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STATE A.Q. PROGRAM

March 8, 2013

Mr. Bill Rogers
Idaho Department of Environmental Quality
1410 N. Hilton
Boise, ID 83706

Subject: Langley Gulch Power Plant
Tier I Air Quality Permit Application

Dear Mr. Rogers:

This letter is being submitted to inform you of the submittal of the initial Tier I permit application for Idaho Power's Langley Gulch Power Plant. The Langley Gulch facility began operations on April 13, 2012 and became commercially available for operations on June 29, 2012. In accordance with IDAPA 58.01.01.313, this application is being submitted within 12 months of commencing operation.

Following the issuance of the Permit-to-Construct (PTC), there were changes to the vendors of the emergency diesel generator and the diesel fire pump. Although the capacity of the generator and the fire pump remained the same, the alternate vendors provided driver engines for the generator and fire pump with slightly different horsepower ratings than those used in the original PTC application. Since the emission estimates for these engines are directly tied to the engine ratings, the emission calculations in this permit application vary slightly from those presented in the PTC.

Idaho Power is not requesting any changes to the PTC permit conditions in this permit application; however, to ensure accuracy the changes to the above mentioned engines has been included. In addition, a request for the provisions of a Permit Shield and Insignificant Activities has been included, which were not in the original PTC.

If you have any questions regarding the contents of this permit application or would like additional information, please contact me at your earliest convenience.

Sincerely,

Trevor Mahlum
Engineer, Power Production

Encl: Tier I Permit Application w/ CD (calculation spreadsheets)

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

Tier 1 Operating Permit Application

Langley Gulch Power Plant
Idaho Power Company

March 2013

Revision History

Submittal	*Date*
Revision 0	3/08/13

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A IDEQ Application Forms
B Detailed Emission Calculation
C Acid Rain Program Permit Application (Copy from Original Application)
D GHG Emission Calculations

1. Introduction

This document presents technical and regulatory compliance information in support of an application for a Tier 1 operating permit from the State of Idaho, Department of Environmental Quality (IDEQ) for the Langley Gulch Power Plant.

Facility:	Langley Gulch Power Plant 3806 Highway 30 South New Plymouth, ID 83655
Owner/Operator:	Idaho Power Company 1221 W. Idaho St. Boise, ID 83702
Responsible Official:	Dale Koger Power Production Manager (208) 388-5820
Facility Contact:	Trevor Mahlum Mechanical Engineer (208) 388-2426

Langley Gulch Power Plant is identified by the following codes and classifications:

- Standard Industrial Classification: 4911
- North American Industry Classification System (NAICS): 221112
- Idaho Department of Environmental Quality Facility ID: 075-00012
- Environmental Protection Agency Facility ID (ORISPL): 57028

Idaho Power Company is submitting this application for an initial Tier 1 operating permit in accordance with IDAPA 58.01.01.313.01(b). Any questions or comments regarding this application should be sent to:

Trevor Mahlum
Mechanical Engineer
Idaho Power Company
1221 W. Idaho St
(208) 388-2426
tmahlum@idahopower.com

Langley Gulch power plant (LGPR) is located in Payette County, approximately 5 miles south of New Plymouth, Idaho; south of Exit 9 on Interstate 84. A map showing the physical location of LGPR is included as Figure 1-1. Payette County has been identified by the Idaho Department of Environmental Quality (IDEQ) as an attainment or unclassifiable area for all regulated criteria pollutants.

In accordance with IDAPA 58.01.01.314, this application submittal includes a project description, process flow diagram, emission rates and control equipment, State and Federal regulatory review, and compliance certifications. IDEQ permit application forms are provided in Appendix A.

LGPR has a nominal capacity of approximately 269 megawatts (MW). The project includes a Siemens SGT6-5000F gas turbine in a one-on-one combined-cycle configuration with a Siemens SST-700 high pressure and SST900RH intermediate pressure steam turbine. The combustion turbine is equipped with a heat recovery steam generator (HRSG) which includes supplemental natural gas firing (duct firing). BACT is incorporated into the design of the facility. Dry low NO_x burners and selective catalytic reduction (SCR) control NO_x emissions. In addition, an oxidation catalyst controls CO and VOC emissions. Good combustion practices and burning pipeline quality natural gas minimize emissions of all remaining pollutants.

In addition to the combustion turbine, other associated emissions equipment for the facility include a diesel-fired emergency generator, a fire pump diesel engine, dry chemical storage silos, and a wet cooling tower. A facility overview drawing is included as Figure 1-2 and a scaled site plan identifying the equipment is provided as Figure 1-3.

Emission rates for each emission source are provided as well as a description of any control equipment.

A process flow diagram of the LGPR Combined Cycle Power Plant is presented in Figure 1-4.

Figure 1-1: Site Location

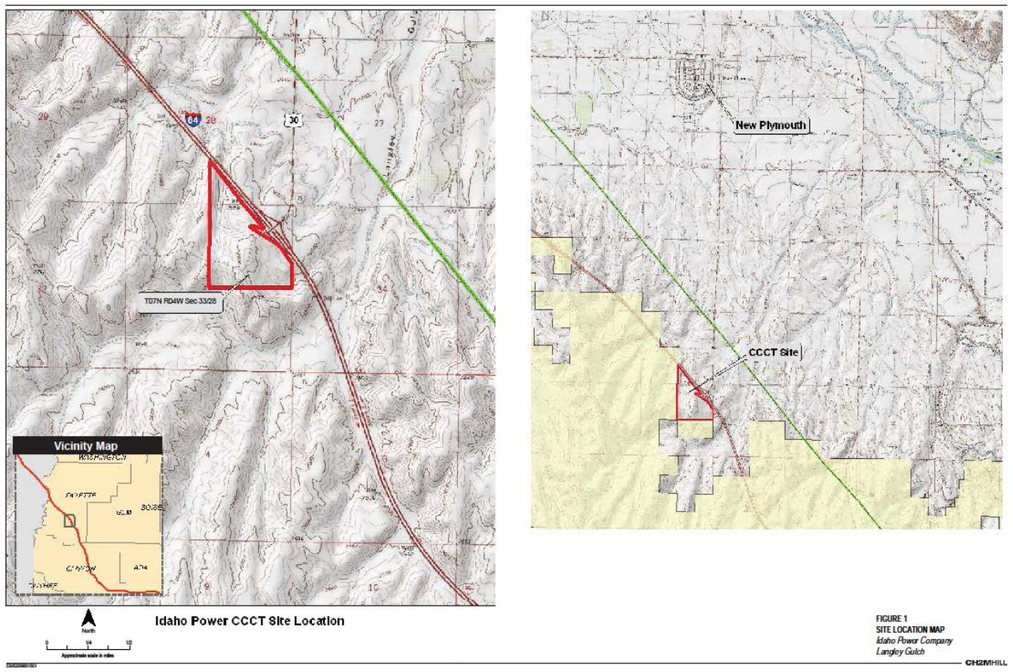


Figure 1-2: Facility Overview

Comment [kmk1]: The text on this map is really hard to read…but looks like DEQ accepted it in the PTC.

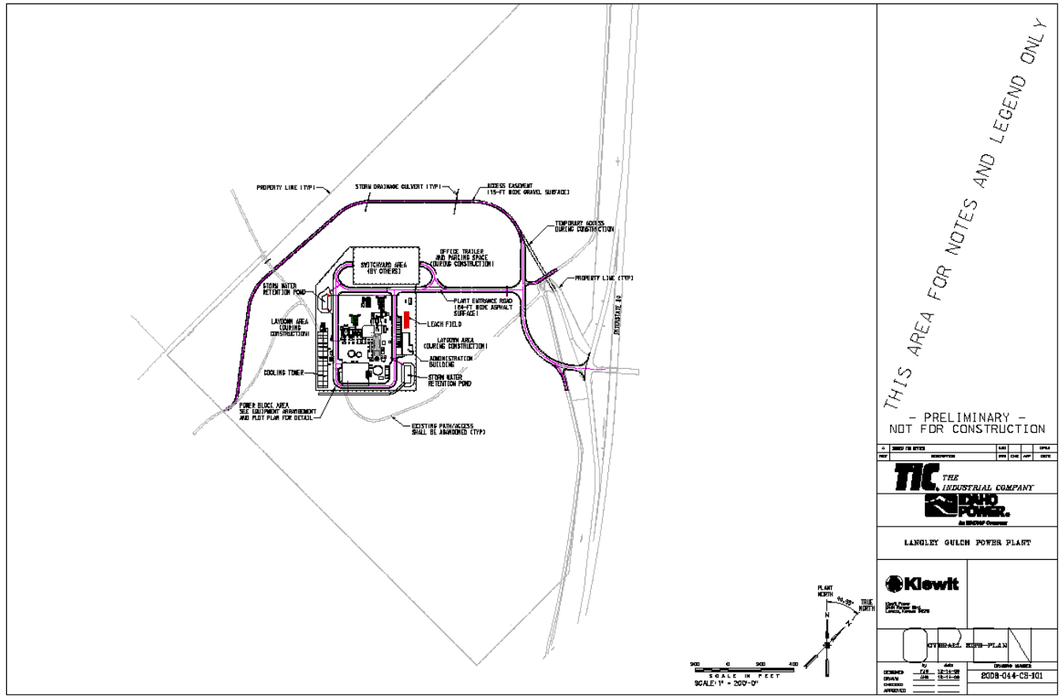


Figure 1-3: Plant Layout

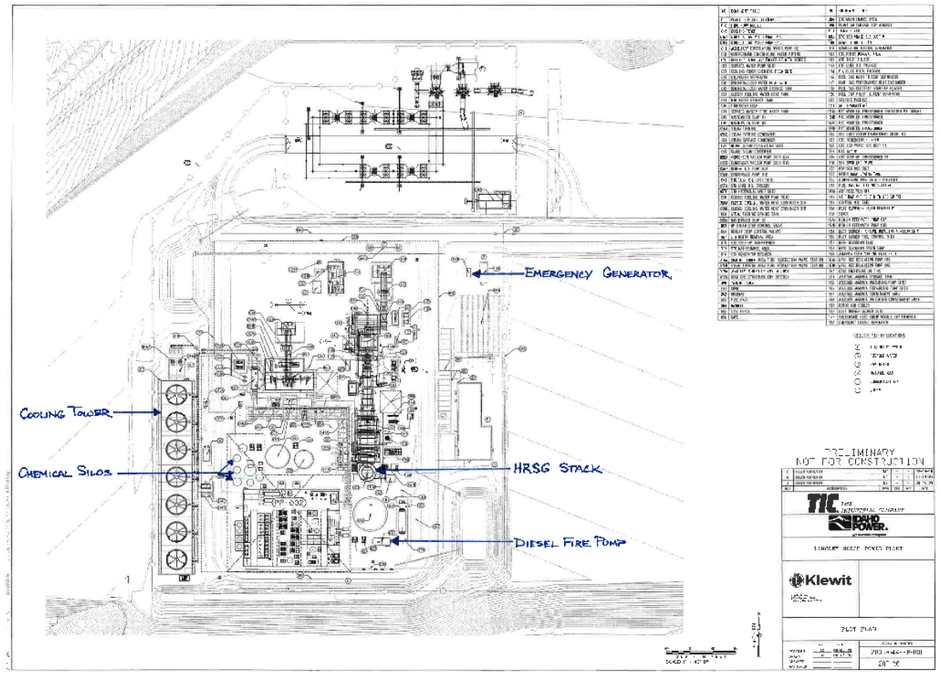
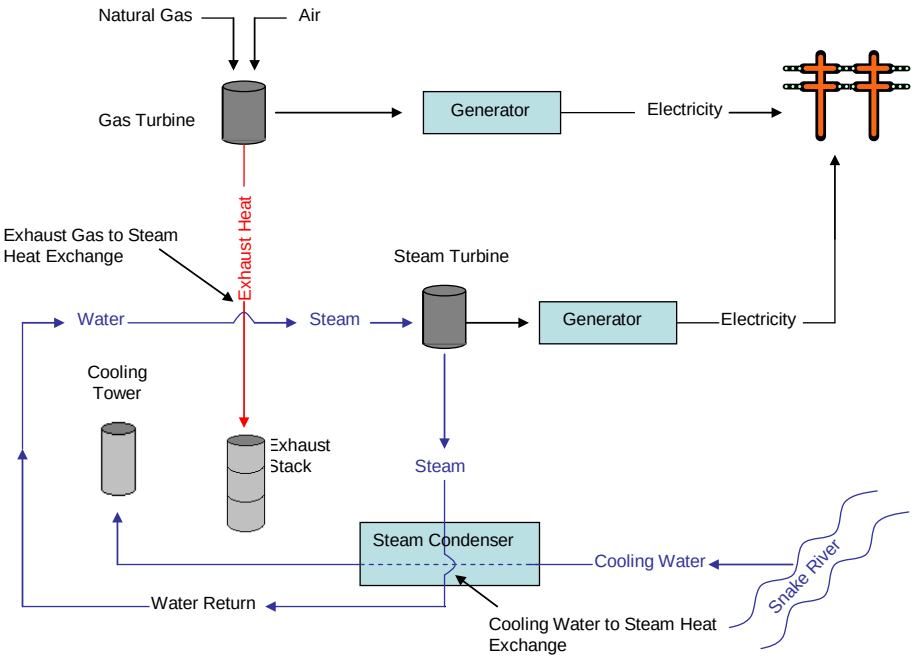


Figure 1-4: Langley Gulch Power Plant - Process Flow Diagram



2. Project Description

Power Block

LGPR 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 HRSG which uses the 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 increase steam production and steam turbine output for peak loads. The maximum heat input for the combustion turbine with duct firing is 2,375 million British thermal units per hour (MMBtu/hr) higher heating value (HHV) (100 percent load at 0ºF).

The HRSG has a 160-foot-tall stack which releases the exhaust gases into the atmosphere. The exhaust stack is equipped with an emission probe for sampling regulated criteria pollutants. The pollutant concentrations of both NOx and CO are continuously monitored using a Continuous Emissions Monitoring System (CEMS).

The F Class combustion turbine uses dry low NO_x (DLN) combustion technology to minimize NO_x formation. SCR and catalytic oxidation systems within the HRSG control emissions of NO_x, CO, and VOCs. Use of pipeline quality natural gas limits the formation of PM_{10}, $PM_{2.5}$, and SO_2 emissions.

With the use of the dry low-NOx (DLN) combustion technology and the SCR, stack emissions of NO_x are limited to 2.0 parts per million by volume, dry (ppmvd), at 15 percent oxygen (O_2). The ammonia slip, or concentration of un-reacted ammonia in the exhaust flue gas, is limited to less than 5.0 ppmvd at 15 percent O_2. There will be onsite storage of 20,000 gallons of 19 percent aqueous ammonia for use with the SCR system. The catalytic oxidation system controls CO and VOC emissions. Stack emissions of both CO and VOCs are limited to 2.0 ppm at 15 percent O_2.

The ammonia storage tank is sealed, resulting in a contained system that releases no fugitive emissions to the environment. The ammonia distribution to the SCR system is through closed piping and is then sprayed into the exhaust gas path in the SCR where the NOx reduction reaction occurs. The only ammonia released to the environment is from the ammonia slip (un-reacted ammonia) discharged through the exhaust stack.

The operational schedule of LGPR is dependent upon many factors including: future load demand, ambient weather, yearly snow pack, and other unpredictable conditions. Due to the varying nature of the operational schedule, LGPR is subject to numerous startup and shutdown events per year. The time period between a shutdown and the subsequent startup defines whether the startup is a cold, warm, or hot start. Startup and shutdown conditions along with expected durations are defined in Table 2-1.

The startup cycle duration begins with the "clock hour" when the turbine first begins to fire fuel and until the "clock hour" when the turbine reaches steady operating load and the SCR reaches normal operating temperatures. The shutdown cycle duration begins with the "clock hour" when the combustion turbine load decreases below 60 percent of full load and

ends with the "clock hour" when fuel flow to the gas turbine is discontinued. On an annual basis, the emissions from the combustion turbine will not exceed the estimates resulting from a maximum of 253 hot starts, 45 warm starts, and 7 cold starts. A maximum of 305 shutdowns are anticipated per year.

Table 2-1: Startup and Shutdown Conditions

Condition	***Time since Shutdown***	***Duration (minutes)***
Hot	Less than 16 hours	125
Warm	More than 16 hours and Less than 64 hours	280
Cold	More than 64 hours	310
Shutdown		41

Ancillary Equipment

The LGPR facility includes: a diesel-fired emergency generator, a diesel fire water pump, a wet cooling tower, dry chemical storage silos, and an electric fuel heater.

Emergency Generator

A 750 kilowatt (kW) Caterpillar diesel fired generator was installed at the facility for operation of emergency systems. This engine driver is rated at 1,214 horsepower (bhp) at full load. The generator is certified to the EPA Tier 2 standards and meets the required emission standards as specified in the BACT analysis. The generator is limited to a maximum of 4 hours per day and 60 hours per year for maintenance and testing activities. Potential emission estimates are based on these self-imposed limits. The generator will operate exclusively on ultra low sulfur diesel fuel.

The emergency generator consists of a 12 cylinder engine with a displacement of 27 liters (L). Therefore, the total displacement per cylinder is equal to 2.25 L/cylinder.

Diesel Fire Pump

A 305 bhp Cummins diesel fired pump was installed at the facility to supply an emergency fire water system. The fire pump engine is certified to the EPA Tier 3 standards and meets the emission requirements as specified in the BACT analysis. The fire pump use will be limited to a maximum of 1 hour per day and 30 hours per year for maintenance and testing activities. Potential emission estimates are based on these self-imposed limits. The fire pump will operate exclusively on ultra low sulfur diesel fuel.

The emergency fire pump consists of a 6 cylinder engine with a displacement of 9 L. Therefore, the total displacement per cylinder is equal to 1.5 L/cylinder.

Wet Cooling Tower

The power plant produces waste heat as a byproduct of the useful electrical energy produced. A seven cell, forced draft wet cooling tower releases the waste heat to the ambient atmosphere by the evaporation of water. The wet cooling tower is equipped with a drift eliminator with a drift rate of 0.0005 percent.

Dry Chemical Storage Silos

The water treatment process requires the use of lime, magnesium oxide, and soda ash for removing suspended solids in the cooling water. These chemicals are stored onsite in bulk storage silos. During chemical loading operations, estimated to happen once per month, small amounts of PM emissions are expected to occur. The silo vents is equipped with filter media to limit the amount of PM emissions. Emissions from the loading events are included in the facility wide emission calculations

3. Emissions Unit Information

This section provides an emissions summary for the LGPR Project.

Emissions rates for the LGPR project include: a Siemens SGT6-5000F combustion turbine operating in combined-cycle mode with supplemental duct firing, an emergency diesel fired generator, a diesel fire pump, a wet cooling tower, and dry storage silos. Additionally, fugitive road dust from on-site access roads to the facility is provided for informational purposes.

Natural Gas Combustion Turbine with Duct Burners

Emissions

The emission rates for the F Class combustion turbine are shown in Table 3-1. Emissions of NO_x, CO, and VOCs are based on BACT emission rate of 2 ppmvd at 15 percent O_2. Emissions for SO_2 and PM_{10} are based on turbine design data and engineering estimates. Emissions in Table 3-1 are estimated at an ambient temperature of 0ºF, with the combustion turbine operating at base load with duct firing.

Table 3-1: Emissions for F-Class Combustion Turbines with Duct Burners

Pollutant	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
NO_x Emissions	20.1	87.7
CO Emissions	12.2	278.1
SO_2 Emissions	3.41	12.5
PM_{10} Emissions	12.55	48.5
VOC Emissions	7.0	74.9
CO_2 Emissions	277,030	1,092,050
CH_4 Emissions	5.2	20.6
N_2O Emissions	0.5	2.1

Table 3-2 shows the annual LGPR toxic air pollutant (TAP) emissions from the F Class combustion turbine combined with natural gas duct firing. Emissions of TAPs were estimated using natural gas emissions factors from EPA's AP-42, Fifth Edition, Table 3.1-3 and Tables 1.4-3 and 1.4-4 for the combustion turbine and duct firing, respectively. Annual emissions are estimated with 7,884 hours of operation per year. HAP emissions for the F Class combustion turbine and combined with duct firing were estimated at 10.4 tpy. Detailed emission calculations are provided in Appendix B.

Table 3-2: TAP Emission Summary for F-Class Combustion Turbine with Duct Firing

Pollutant	***24-Hr Ave. Emissions (lb/hr)***	***Annual Ave. Emissions (lb/hr)***
3-Methylchloranthrene		3.93E-07
Ammonia	1.86E+01	
Benzene		2.35E-02
Benzo(a)pyrene		2.62E-07
Formaldehyde		1.38E+00
Hexane	4.36E-01	
Naphthalene		2.92E-03
Pentane	6.30E-01	
Toluene	2.78E-01	
Flourene		6.11E-07
Xylenes	1.37E-01	
Acetaldehyde		7.68E-02
Acrolein	1.37E-02	
1,3-Butadiene		8.26E-04
Nitrous Oxide	6.94E+00	
Sulfuric Acid	2.61E-01	
PAH		7.34E-03
POM		2.36E-06
Arsenic		4.36E-05
Barium	1.07E-03	
Beryllium		2.62E-06
Cadmium		2.40E-04
Chromium	3.39E-04	
Cobalt	2.04E-05	
Copper	2.06E-04	
Manganese	9.21E-05	
Mercury	6.30E-05	
Molybdenum	2.67E-04	
Nickel		4.58E-04
Selenium	5.82E-06	
Vanadium	5.58E-04	
Zinc	7.03E-03	

Operating Profile

The combustion turbine can operate at a wide range of electrical output levels while achieving the permitted BACT emission concentrations. The turbine utilizes automatic control logic to adjust fuel fractioning and cooling flows in order to reduce the emission levels at varying output levels. Depending on the ambient conditions, the output can be

turned down to approximately 50% of full load while meeting all permitted emission levels. Real-time CEMS data is used to verify that the turbine is within the permitted emission range. In addition, both the combustion turbine and the duct burners operate exclusively on pipeline quality natural gas which limits the SO_2 and PM emissions by the maximum fuel throughput.

Emissions Control Systems and Monitoring

The combustion turbine has dry low NOx burners as an integral part of the combustion system. The burners are in use any time the combustion turbine is operated and cannot be taken out of service. The burners fraction the fuel into the turbine to optimize the fuel-to-air ratio in order to get a lean burn and limit the production of thermal NOx. Downstream of the turbine exhaust, inside the HRSG, an oxidation catalyst and a selective catalytic reduction system are installed for further emissions reduction. The oxidation catalyst is a dry, precious metal catalyst. The catalyst oxidizes the flue gas as it passes through, reducing the emissions of both CO and VOCs. The catalyst is permanently installed and requires no support systems to be activated; however, the removal efficiency of the catalyst is reduced at low temperature. Therefore, during a startup event, the catalyst efficiency is reduced until flue gas temperatures rise and subsequently heat up the catalyst bed. Through historical observations, the catalyst efficiency begins to increase approximately 20-30 minutes after the combustion turbine starts. The selective catalytic reduction system is immediately downstream of the oxidation catalyst. The blower pulls hot flue gas from the HRSG through an ammonia conditioning skid. The liquid ammonia (19% aqueous) is sprayed into a mixing chamber with the hot flue gas where it vaporizes. The vaporized ammonia is then sent into a grid of injection nozzles upstream of the catalyst bed and mixes with the flue gas. As the flue gas and ammonia contact the catalyst bed, the NOx and NH_3 react and produce nitrogen gas and water vapor as an outlet product. This system relies on the vaporization of the ammonia to work effectively, and therefore, cannot be operated until the temperature of the catalyst and flue gas elevated. During a startup event, the ammonia system is activated when the turbine output is approximately 50-60 percent of full load. Once activated, the ammonia system stays operational throughout the entire range of operations for the combustion turbine. At the stack exit, a CEMS umbilical pulls real-time samples of the flue gas and returns them to the emissions analyzers. The analyzers read the NOx, CO, and O_2 values of the exiting flue gas into the atmosphere. The real-time and calculated hourly averages of the pollutants are sent to the onsite operator to ensure the emissions control systems are operating within the established ranges. The CEMS system is calibrated on a daily basis to ensure accuracy. In addition, the CEMS is subjected to a linearity check quarterly and an annual relative accuracy test audit in accordance with the quality assurance checks required under 40 CFR 75; Continuous Emissions Monitoring.

Equations

The hourly emission rates for the combustion turbine are based upon the guarantee values provided by the turbine vendor and emission control equipment vendors. The annual emissions were based upon the maximum hourly emissions, maximum operating profile and sum of startup and shutdown emissions. The equations for estimating emissions are included in with the emission calculations.

Emergency Generator

LGPR includes a 750 kW diesel fired emergency generator. The emergency generator will be operated no more than 4 hours per day and 60 hours per year for maintenance and testing. Emissions of criteria pollutants are estimated using 40 CFR 89.112 (*Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines*) and emission factors from EPA's AP-42, Fifth Edition, Table 3.4-1. The LGPR emergency generator TAP emissions are estimated using emission factors from EPA's AP-42, Fifth Edition, Table 3.4-3 and Table 3.4-4. Emissions from the emergency generator are summarized in Table 3-5 and Table 3-6. HAP emissions for the emergency generator are negligible. Detailed emission calculations are provided in Appendix B.

Table 3-3: Criteria Pollutant Emissions Summary for 750 kW Emergency Generator

	Generator
Engine Rating (kW)	750
Annual Hours of Operations (hours/year)	60
NO_x Emissions (lb/hr)	12.8
CO Emissions (lb/hr)	7.0
PM_{10} Emissions (lb/hr)	0.4
SO_2 Emissions (lb/hr)	0.01
VOC Emissions (lb/hr)	0.8
NO_x Emissions (tpy)	0.39
CO Emissions (tpy)	0.21
PM_{10} Emissions (tpy)	0.01
SO_2 Emissions (tpy)	0.00
VOC Emissions (tpy)	0.02

Table 3-4: TAP Emissions Summary for 750 kW Emergency Generator

Pollutant	***24-Hour Average Emission (lb/hr)***	***Annual Average Emissions (lb/hr)***
Acenaphtene		2.35E-07
Acenaphthylene		4.64E-07
Acetaldehyde		1.27E-06
Acrolein	9.65E-06	
Anthracene		6.19E-08
Benzene		3.90E-05
Benzo(a)pyrene		1.29E-08
Benz(g,h,l)perylene		2.80E-08
Fluorene		6.44E-07
Formaldehyde		3.97E-06
Naphthalene	1.59E-04	
Phenanthrene		2.05E-06
Propylene Oxide	3.42E-03	
POM (7-PAH Group)		1.95E-07
Pyrene		1.87E-07
Toluene	3.44E-04	
Total PAH		1.07E-05
Xylenes	2.36E-04	

Fire Pump

LGPR includes a 305 bhp diesel fired fire pump. The fire pump will be operated no more than 1 hour per day and 30 hours per year for testing and maintenance. Emissions of criteria pollutants are estimated using 40 CFR 60 Subpart IIII Emission Standards for stationary compression ignition internal combustion engines and emission factors from EPA's AP-42, Fifth Edition, Table 3.3-1. The LGPR fire pump TAP emissions are estimated using emission factors from EPA's AP-42, Fifth Edition, Table 3.3-2. Emissions from the fire pump are summarized in Table 3-7 and Table 3-8. HAP emissions for the fire pump are negligible. Detailed emission calculations are provided in Appendix B.

Table 3-5: Criteria Pollutant Emissions Summary for 305bhp Fire Pump

	Fire Pump
Engine Rating (bhp)	305
Annual Hours of Operations (hours/year)	30
NO_x Emissions (lb/hr)	2.0
CO Emissions (lb/hr)	1.7
PM_{10} Emissions (lb/hr)	0.10
SO_2 Emissions (lb/hr)	0.00
VOC Emissions (lb/hr)	0.10
NO_x Emissions (tpy)	0.03
CO Emissions (tpy)	0.03
PM_{10} Emissions (tpy)	0.00
SO_2 Emissions (tpy)	0.00
VOC Emissions (tpy)	0.00

Table 3-6: TAP Emissions Summary for 305 bhp Fire Pump

Pollutant	***24-Hour Average Emissions (lb/hr)***	***Annual Average Emissions (lb/hr)***
1,3-Butadiene		2.90E-07
Acenaphthene		1.00E-08
Acenaphthylene		3.56E-08
Acetaldehyde		5.40E-06
Acrolein	7.92E-06	
Anthracene		1.32E-08
Benzene		6.57E-06
Benzo(a)pyrene		1.32E-09
Benz(g,h,l)perylene		3.44E-09
Fluoranthene		5.36E-08
Formaldehyde		8.31E-06
Naphthalene		7.26E-06
Phenanthrene		2.07E-07
Propylene Oxide	2.21E-04	
POM (7-PAH Group)		1.23E-08
Pyrene		3.36E-08
Toluene	3.50E-05	
Total PAH		1.18E-06
Xylenes	2.44E-05	

Cooling Tower

LGPR includes a forced draft, wet cooling tower equipped with drift eliminators with a drift rate of 0.0005 percent. The water flow rate is approximately 63,200 gpm with a maximum dissolved solids concentration of 5,000 parts per million by weight at nine cycles of concentration on the tower water. Particulate matter emissions are estimated using emission factors from EPA's AP-42, Fifth Edition, Table 13.4-1 and from a technical paper presented at the 2001 Air and Waste Association Management, *Calculating Realistic PM_{10} Emissions from Cooling Towers, J. Reisman and G. Frisbie.* Emissions from the cooling tower are summarized in Table 3-9. Detailed emission calculations are provided in Appendix B.

Table 3-7: Criteria Pollutant Emissions Summary for Cooling Tower

Pollutant	***Cooling Tower***
PM_{10} Emissions (lb/hr)	0.66
PM_{10} Emissions (tpy)	2.91

Dry Chemical Storage Silos

Three dry chemical storage silos are installed at the facility to house chemicals required in the water treatment process. The silos are enclosed from the environment with a vent installed near the peak of the silo to allow for equalization of pressure during chemical loading. The vents are equipped with bin vent filters which capture airborne particulate matter. The filters have a pulse air system to blast the captured PM off the filter and back into the silo. The silos are designed to hold a 30-day supply of chemicals to reduce loading time to approximately once per month. Loading the silo is expected to take approximately one hour per silo. For modeling purposes, the loading process was conservatively estimated to last 2 hours for each silo, with each silo being loaded twice per month.

Table 3-8: Criteria Pollutant Emissions Summary for Storage Silos

Pollutant	***Storage Silos***
PM_{10} Emissions (lb/hr)	0.13
PM_{10} Emissions (tpy)	0.01

Note: Emission numbers represent total for a maximum of six silos.

Fugitive Emissions

The only source of fugitive dust emissions will be generated from on-site road traffic. The project site has a paved entrance road up to the administration building and around the site perimeter. The maintenance roads surrounding the facility are unpaved, gravel roads.

4. Applicable Requirements & Compliance

Facility Wide Requirements

Fugitive Dust

The facility must comply with the rules to control fugitive dust in accordance with IDAPA 58.01.01.650-651. [PTC Condition]

- The facility complies with the conditions by performing quarterly fugitive dust inspections. In addition, site improvements to minimize fugitive dust include paving of onsite roads and applying washed rock to the grounds.

Odors

The facility must not discharge odorous gases, liquids, or solids in accordance with IDAPA 58.01.01.776. [PTC Condition]

- No odorous substances are emitted from the facility. In the event that odorous substances are discharged, the facility will take immediate actions to mitigate the source and will maintain records if complaints are received.

Visible Emissions

The facility must comply with the rules to prevent visible emissions for each permitted emission source in accordance with IDAPA 58.01.01.625 [PTC Condition]

- The facility complies with the conditions by performing quarterly visible emission inspections for each permitted emission source. A "see" or "no see" evaluation is performed and any "see" evaluations are mitigated and an excess emissions report is submitted.

Process Weight Limitations

The facility must comply with the PM emissions limit in accordance with IDAPA 58.01.01.700-703 for the storage silos and the cooling tower. [PTC Condition]

- The facility complies with the process weight limitations for the storage silos and the cooling tower by utilizing emission control devices and permit limitations.
    - Storage silos are equipped with bin vent filters and are limited to 48 hours of loading time per year. A typical load of dry chemical is 48,000 lbs. In accordance with IDAPA 58.01.01.701.03, the emissions must not exceed 15.56 lb/hr. The silo emissions are calculated to be 0.13 lb/hr.
    - Cooling tower is equipped with drift eliminators and has a TDS limit of 5,000 ppm. The maximum dissolved solids allowable in the cooling tower water are calculated to be 158,126 lbs. In accordance with IDAPA 58.01.01.701.03, the emissions must not exceed 23.26 lb/hr. The cooling tower emissions are calculated to be 0.66 lb/hr.

Fuel Burning Equipment

The facility must comply with the PM emission limit in accordance with IDAPA 58.01.01.676 for the duct burners. [PTC Condition]

- The facility complies with the fuel burning equipment PM emission limit by operating the duct burners exclusively on pipeline quality natural gas. The PM emissions from the duct burners are guaranteed to be 2.4 lb/hr which is equal to 0.0007 gr/dscf @ 3% O_2. The limit for PM grain loading is 0.015 gr/dscf @ 3% O_2.

Fuel Sulfur Content

The facility must comply with the sulfur content limitations in accordance with IDAPA 58.01.01.725. [PTC Condition]

- The facility only purchases diesel fuel that is rated for 15 ppm sulfur content. Fuel receipts are filed onsite.

Excess Emissions

The facility must comply with the rules pertaining to excess emissions in accordance with IDAPA 58.01.01.130-136 for all permitted emission sources. [PTC Condition]

- The facility complies with the excess emissions rules through the use of a CEMS (combustion turbine and duct burner emissions), hourly runtime limits (combustion turbine, duct burner, fire pump, emergency generator, and storage silos), process weight restrictions (storage silos and cooling tower), visible emission observations, and fuel sulfur content (natural gas and diesel fuel).
- In the event of an excess emissions event, the DEQ is notified with 24 hours of the event and a detailed excess emissions report is filed within 15 days of the event.

Test Methods

The facility shall use the approved test methods listed in the PTC or as determined acceptable by the DEQ to determine emissions compliance during any performance testing in accordance with IDAPA 58.01.01.157.02. [PTC Condition]

- The facility complies with the condition by submitting a testing protocol to the DEQ prior to the test date.

Combustion Turbine

Emission Limits

The combustion turbine must comply with the BACT and NSPS emission limits in accordance with PTC conditions 33-40. [PTC Condition]

- The combustion turbine is equipped with a CEMS to monitor and record real time NOx and CO emissions to verify compliance with conditions 33-35 and 37.
- The CEMS calculates the 12-month cumulative emissions of NOx and CO to verify compliance with condition 36.

- The combustion turbine and duct burner are operated exclusively on pipeline quality natural gas which contains less than 0.5 gr/hscf of sulfur. Natural gas has an heat content of approximately 994 btu/scf, therefore, the sulfur content of the pipeline natural gas is 0.0006 lb/MMbtu which is in compliance with condition 38.
- The emissions from the HRSG stack cannot exceed 12.55 lb/hr of PM. An initial emissions compliance performance test was performed. The PM emissions were verified to be less than the limit in condition 39.
- The ammonia slip from the HRSG stack shall not exceed 5 ppm @ 15% O_2 on a 3-hour rolling average. An initial emissions compliance performance test was performed and verified compliance with condition 40.

Operating Requirements

The combustion turbine must comply with the operational and design requirements in accordance with PTC conditions 41-50.

- The HRSG is equipped with an SCR to reduce the NOx emissions. Ammonia flow and a NOx CEMS provides monitoring capability to ensure the SCR is functioning properly.
- The HRSG is equipped with a catalytic oxidation system to reduce CO and VOC emissions. The CO CEMS provides monitoring capability to ensure the catalyst is functioning properly.
- Good combustion practices are integral into the design of the combustion turbine and duct burners. CEMS provides real time monitoring of the pollutants to verify good combustion as well as real time monitoring of the combustion system thermocouples.
- A NOx CEMS is installed and operated in accordance with the requirements of 40 CFR 75. The CEMS was certified to the requirements listed under 40 CFR 75.20.
- A CO CEMS is installed and operated in accordance with the requirements of 40 CFR 75. The CEMS was certified to the requirements listed under 40 CFR 75.20.
- The combustion turbine and pollution control equipment are maintained in accordance with the manufacturer's recommendations. Real time monitoring of the turbine operation and pollutant concentrations provide verification that the equipment is functioning properly.
- The Combustion turbine operates exclusively on pipeline quality natural gas. The natural gas was tested for sulfur content during the certification testing.
- The ammonia injection flow meter is installed an operated in accordance with the manufacturer's recommendations. The meter will be calibrated every 5 years.
- The ammonia injection flow rate is limited to 1.03 gpm on an hourly average. Real time monitoring and recording of the ammonia flow is on the CEMS.

- Operating hours for both the combustion turbine and the duct burners is monitored and recorded by the plant distributed control system (DCS).

Continuous Monitoring and Recordkeeping

The combustion turbine and duct burner operations and emissions are monitored and recorded in accordance with the permit conditions 51-58.

- Each startup, shutdown, and low-load event is monitored and recorded by both the plant DCS and the CEMS.
- The NOx CEMS is installed and operated in accordance with 40 CFR 75. All modes of operation are monitored continuously and any excess emissions or monitor downtimes are recorded. Testing protocols and testing reports are submitted to the DEQ for any required performance testing. All records are maintained for 5 years.
- The NOx CEMS calculates and records the following: 1-hour NOx ppm, 1-hour NOx lb/hr, 3-hour NOx ppm, 12-month NOx tons, 1-hr applicable NOx limit, 3-hour applicable "blended average" limit, and any excess emissions produce an alarm.
- A NOx CEMS is installed.
- The NOx CEMS was certified in accordance with Performance Specification 2 of 40 CFR 60 Appendix B. The CEMS collects adequate data to validate each emissions hour and will automatically substitute data if the hour does not have validated data. The fuel flow meter is calibrated annually. No watt, steam, pressure or temperature devices feed into the CEMS logic, and therefore, no calibrations are required for accurate CEMS readings. The CEMS QA requirements are in accordance with 40 CFR 75 and the manufacturer's recommendations.
- All data collected by the CEMS is reduced to hourly averages. Substitute data is used if the O_2 concentration exceeds 19%. The validated data is used to identify excess emissions and semiannual reports are submitted that detail the CEMS downtime periods. The monthly emissions are verified to be within the limits listed under Table 1 of 40 CFR 60, Subpart KKKK.
- The CO CEMS is installed and operated in accordance with 40 CFR60, Subpart A. All modes of operation are monitored continuously and any excess emissions or monitor downtimes are recorded. Testing protocols and testing reports are submitted to the DEQ for any required performance testing. All records are maintained for 5 years.
- The CO CEMS calculates and records the following: 1-hour CO ppm, 1-hour CO lb/hr, 3-hour CO ppm, 12-month CO tons, 1-hr applicable CO limit, 3-hour applicable "blended average" limit, and any excess emissions produce an alarm.

Monitoring and Recordkeeping

The facility maintains records to verify compliance with the fuel requirements, ammonia injection flow rate, and the hours of operation for the combustion turbine and duct burners.

- The natural gas fired in the combustion turbine is verified to meet the requirements of pipeline natural gas in accordance with 40 CFR 75, Appendix D, Section 2.3.1.4(a)(3). The testing frequency (annually) of the gas is in accordance with 40 CFR 75, Appendix D, Table D-5.
- The CEMS is used to record the ammonia injection flow rate and verified not to exceed the limit.
- The plant DCS monitors and records the operating hours of both the combustion turbine and the duct burners.

Performance Testing

The facility shall comply with the performance testing requirements listed in permit conditions 64 – 68.

- The initial performance testing for the combustion turbine was completed on June 17, 2012. Compliance with each permit limit was verified.
- An fuel sulfur content analysis was performed during the performance testing to verify that the fuel met the definition of pipeline natural gas.
- A nine run RATA was performed to ensure the accuracy of the CEMS.

Reporting

The facility complies with the reporting requirements defined in permit conditions 69-72.

- Excess emission and monitor downtime summary reports are submitted semiannually to the DEQ. Performance test reports are submitted annually.
- Excess emissions and downtime are verified against the 40 CFR 60, Subpart KKKK limits.
- Excess emissions of sulfur are determined to occur if the results of the lab analysis indicate that the sulfur content exceeds 0.5 gr/hscf in accordance with the pipeline natural gas definition in 40 CFR 72.2.
- Semiannual reports, including the CEMS downtime report and any excess emission reports are submitted each 6-month period.

Emergency Diesel Generator and Diesel Fire Pump

Emission Limits

The emergency diesel generator and the diesel fire pump are operated and maintained in order to comply with the permitted emission limits.

- An emergency diesel generator certified to the EPA Tier 2 standards was purchased, installed and operated to ensure compliance with the permitted emission levels.
- A diesel fire pump certified tot the EPA Tier 3 standards was purchased, installed, and operated to ensure compliance with the permitted emission levels.

Operating Requirements

The facility shall comply with the operating requirements listed under permit conditions 77 – 82 to ensure compliance.

- The emergency generator is not operated in excess of 4 hours per day or 60 hours per year for maintenance and testing purposes. The diesel fire pump is not operated in excess of 1 hour per day or 30 hours per year for maintenance and testing purposes.
- The emergency generator and fire pump installed, maintained, and operated in accordance with the manufacturer's instructions.
- The emergency generator and the fire pump are operated and maintained in accordance with the manufacturer's recommendation. In addition, both engines are operated exclusively on ultra low sulfur diesel (ULSD).
- The emergency generator and the fire pump have non-resettable hour meters installed.

Monitoring and Recordkeeping

The facility shall monitor and keep records to ensure compliance with permit conditions 83 – 86.

- An excel spreadsheet log is filled out for both the emergency generator and the fire pump each day that they are operated. The log calculates the monthly and 12-month operating time.

Cooling Tower

Operating Requirements

The facility shall comply with the operating requirements listed in permit conditions 87 – 90 to ensure compliance.

- The cooling tower was designed and constructed with drift eliminators to minimize the PM emissions.
- The drift eliminators are permanently installed in the cooling tower and cannot be taken out of service.
- The cooling tower is operated in accordance with the manufacturer's instructions.
- The total dissolved solids (TDS) limit is maintained below the permitted levels by blowing down concentrated water and making up with clean water. The system flow rate is maintained within the limits by throttling the riser valves.

Monitoring and Recordkeeping

The plant DCS system monitors and records the cooling tower operations continuously.

- Electronic records are available to verify both the conductivity and flow rate of the system.

Dry Chemical Storage Silos

Operating Requirements

The facility shall comply with the operating requirements listed under permit conditions 92-94.

- The dry chemical silos have bin vent filters installed, which capture the PM emissions during loading operations
- The bin vent filter is installed and operated in accordance with the manufacturer's instructions any time material is loaded into the silo.
- An O&M manual has been developed which describes the methods used to ensure the integrity of the bin vent filter is maintained in accordance with the good operating practices.

Permit to Construct General Provisions

General Compliance

The facility must comply with all terms and conditions of the Permit to Construct and with the Rules for the Control of Air Pollution in Idaho.

- The conditions of the permit are verified to be in compliance. Monitoring and recordkeeping terms of the permit are maintained at the facility.

Inspection and Entry

The facility shall comply with the requirement that DEQ employees may enter the facility and review the recordkeeping documents, inspect the facility, and/or sample the substances to ensure compliance.

Construction and Operation Notification

The facility shall comply with the notification requirements under permit condition 99.

- A notification of the date of initiation of construction was submitted on 7/12/10.
    - No delays or suspensions of construction occurred, and therefore, no notification was required.
- A notification of the anticipated date of initial startup was submitted on 3/19/12.
- A notification of the actual date of initial startup was submitted on 4/16/12.
- The facility has not reached the maximum production rate, and therefore, no notification has been submitted.

Performance Testing

The facility will comply with the performance testing conditions under permit conditions 100-102.

- A testing protocol was submitted to the DEQ on 5/17/12 which detailed the intended testing and monitoring that was expected to take place.
- A notification of the upcoming testing was submitted to the DEQ on 5/22/12 to allow a representative to be onsite during the testing.
- A testing report was submitted following the testing, which summarized the results and verified compliance with the permitted emission levels.

Monitoring and Recordkeeping

The records related to the conditions of the Permit to Construct, as well as records which support the control equipment, operating conditions and other air quality related functions are maintained for 5 years.

Certification

All documents and reports submitted to the DEQ in relation to the Permit to Construct are certified to be true, accurate, and complete by the Responsible Official.

False Statements

No knowingly false statements or certifications are made.

Tampering

No monitoring devices or methods for compliance verification are tampered with or purposely made inaccurate.

Insignificant Activities

The following activities are requested to be included under the Tier 1 operating permit.

- Operation, loading and unloading of volatile organic compound storage tanks, ten thousand (10,000) gallons capacity or less, with lids or other appropriate closure, vp not greater than eighty (80) mm Hg at twenty-one (21) degrees C. Operation, loading and unloading of gasoline storage tanks, ten thousand (10,000) gallons capacity or less, with lids or other appropriate closure.
- Welding using not more than one (1) ton per day of welding rod.
- Space heaters and hot water heaters using natural gas, propane or kerosene and generating less than five million (5,000,000) Btu/hr.

5. State and Federal Regulation Applicability

A full state and federal regulatory applicability analysis was included in both the original PTC application and the DEQ issued Statement of Basis. The following federal applicability shows the rules that have been promulgated since the original application was submitted.

40 CFR 52

§52.21(b)(49) (49) Subject to regulation means, for any air pollutant, that the pollutant is subject to either a provision in the Clean Air Act, or a nationally-applicable regulation codified by the Administrator in subchapter C of this chapter, that requires actual control of the quantity of emissions of that pollutant, and that such a control requirement has taken effect and is operative to control, limit or restrict the quantity of emissions of that pollutant released from the regulated activity. Except that:

(i) Greenhouse gases (GHGs), the air pollutant defined in § 86.1818-12(a) of this chapter as the aggregate group of six greenhouse gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, shall not be subject to regulation except as provided in paragraphs (b)(49)(iv) through (v) of this section and shall not be subject to regulation if the stationary source maintains its total source-wide emissions below the GHG PAL level, meets the requirements in paragraphs (aa)(1) through (15) of this section, and complies with the PAL permit containing the GHG PAL.

(ii) For purposes of paragraphs (b)(49)(iii) through (v) of this section, the term tpy CO 2 equivalent emissions (CO 2 e) shall represent an amount of GHGs emitted, and shall be computed as follows:

(a) Multiplying the mass amount of emissions (tpy), for each of the six greenhouse gases in the pollutant GHGs, by the gas's associated global warming potential published at Table A-1 to subpart A of part 98 of this chapter—Global Warming Potentials. For purposes of this paragraph, prior to July 21, 2014, the mass of the greenhouse gas carbon dioxide shall not include carbon dioxide emissions resulting from the combustion or decomposition of non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms (including products, by-products, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material).

(b) Sum the resultant value from paragraph (b)(49)(ii)(a) of this section for each gas to compute a tpy CO2 e.

6. References

EPA. 1990. *New Source Review Workshop Manual, Draft,* Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, October, 1990.

EPA. 1995. SCREEN3, Model User's Guide, EPA 454/B-95-004, September 1995.

EPA. 2004. *User's Guide for the AERMOD Meteorological Preprocessor, AERMET*. Office of Air Quality Planning and Standards. November 2004.

EPA. 2004. *User's Guide for the AMS/EPA Regulatory Model, AERMOD*. Office of Air Quality Planning and Standards. September 2004.

EPA. 2005. Appendix W of 40 CFR Part 51—*Guideline On Air Quality Models (Revised)*, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, November 2005.

EPA. 2009. *AERMOD Implementation Guide.* Office of Air Quality Planning and Standards. March 2009.

FLAG. 2008. Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report. Revised 2008.

IDEQ. 2002. *State of Idaho, Air Quality Modeling Guidelines (AQ-011).* Idaho Department of Environmental Quality. December 2002.

IDEQ. 2010. *Langley Gulch Power Plant, Permit-to-Construct.* Idaho Department of Environmental Quality. June 2010

DEQ AIR QUALITY PROGRAM
1410 N. Hilton, Boise, ID 83706
For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Cover Sheet for Air Permit Application – Tier I **Form CSTI**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

COMPANY NAME, FACILITY NAME, AND FACILITY ID NUMBER

1. Company Name	Idaho Power Company		
2. Facility Name	Langley Gulch Power Plant	3. Facility ID No.	075-00012
4. Brief Project Description - One sentence or less	Combined Cycle Power Plant		

PERMIT APPLICATION TYPE

5. ☒ Initial Tier I ☐ Tier I Administrative Amendment ☐ Tier I Minor Modification ☐ Tier I Significant Modification
☐ Tier I Renewal: Permit No.:_____ Date Issued:_____

FORMS INCLUDED

Included	N/A	Forms		DEQ Verify
☒	☐	Form CSTI – Cover Sheet		☐
☒	☐	Form GI – Facility Information		☐
☒	☐	Form EU0 – Emissions Units General		☐
☒	☐	Form EU1– Industrial Engine Information	Please specify number of EU1s attached: 2	☐
☐	☐	Form EU2– Nonmetallic Mineral Processing Plants	Please specify number of EU2s attached: _____	☐
☐	☐	Form EU3– Spray Paint Booth Information	Please specify number of EU3s attached: _____	☐
☒	☐	Form EU4– Cooling Tower Information	Please specify number of EU4s attached: 1	☐
☐	☐	Form EU5 – Boiler Information	Please specify number of EU5s attached: _____	☐
☐	☐	Form CBP– Concrete Batch Plant	Please Specify number of CBPs attached: _____	☐
☐	☐	Form HMAP – Hot Mix Asphalt Plant	Please specify number of HMAPs attached:	☐
☐	☐	PERF – Portable Equipment Relocation Form		☐
☐	☐	Form BCE– Baghouses Control Equipment		☐
☐	☐	Form SCE– Scrubbers Control Equipment		☐
☐	☐	Form VSCE – Venturi Scrubber Control Equipment		☐
☐	☐	Form ESP – Electrostatic Precipitator		☐
☒	☐	Form AO – Afterburner/Oxidizer		☐
☐	☐	Form CYS – Cyclone Separator		☐
☐	☐	Form CA – Carbon Adsorber		☐
☒	☐	Forms EI-CP1 - EI-CP4– Emissions Inventory-- criteria pollutants	(Excel workbook, all 4 worksheets)	☐
☒	☐	Form CAM – Compliance Assurance Monitoring		☐
☒	☐	Form FRA – Federal Regulation Applicability		☐

DEQ AIR QUALITY PROGRAM
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General Information **Form GI**
Revision 7
6/29/12

Please see instructions on back page before filling out the form. All information is required. If information is missing, the application will not be processed.

Identification

1. Facility name Langley Gulch Power Plant

2. Existing facility identification number 075-00012

☐ **Check if new facility (not yet operating)**

3. Brief project description Combined Cycle Power Plant

Facility Information

4. Primary facility permitting contact name Trevor Mahlum **Contact type** Facility permitting contact

Telephone number 208-388-2426 **E-mail** tmahlum@idahopower.com

5. Alternate facility permitting contact name Dale Koger **Alternate contact type** Responsible official

Telephone number 208-388-5820 **E-mail** dkoger@idahopower.com

6. Mailing address where permit will be sent (street/city/county/state/zip code) 1221 W. Idaho St / Boise / Ada / Idaho / 83702

7. Physical address of permitted facility (if different than mailing address) (street/city/county/state/zip code) 3806 Highway 30 South / New Plymouth / Payette / Idaho / 83655

8. Is the equipment portable? ☐ **Yes*** ☒ **No** ***If yes, complete and attach PERF; see instructions.**

9. NAICS codes: Primary NAICS 221112 **Secondary NAICS**

10. Brief business description and principal product produced Electric Generating Facility

11. Identify any adjacent or contiguous facility this company owns and/or operates N/A

12. Specify type of application ☐ **Permit to construct (PTC); application fee of $1,000 required. See instructions.**

☒ **Tier I permit** ☐ **Tier II permit** ☐ **Tier II/Permit to construct**

For Tier I permitted facilities only: If you are applying for a PTC then you must also specify how the PTC will be incorporated into the Tier I permit.

☐ **Co-process Tier I modification and PTC** ☐ **Incorporate PTC at the time of Tier I renewal** ☐ **Administratively amend the Tier I permit to incorporate the PTC upon applicant's request (IDAPA 58.01.01.209.05.a, b, or c)**

Certification

In accordance with IDAPA 58.01.01.123 (Rules for the Control of Air Pollution in Idaho), I certify based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

13. Responsible official's name Dale Koger **Official's title** Power Production Manager

Official's address 1221 W. Idaho St / Boise / Ada / Idaho / 83702

Telephone number 208-388-5820 **E-mail** dkoger@idahopower.com

Official's signature Dale Koger **Date** 3-11-13

☒ **14. Check here to indicate that you want to review the draft permit before final issuance.**

DEQ AIR QUALITY PROGRAM
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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Idaho Power Company	Langley Gulch Power Plant	075-00012

4. Brief Project Description: Combined Cycle Power Plant

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	HRSG STACK
6.	EU ID Number:	HRSG
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #: Date Issued:
8.	Manufacturer:	SIEMENS
9.	Model:	SGT6-5000F4
10..	Maximum Capacity:	2134 MMBtu/hr (Turbine); 241 MMBtu/hr (Duct Burner
11.	Date of Construction:	2010
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Selective Catalytic Reduction (SCR1) and Oxidation Catalyst (CAT1)
15. Date of Installation:	2010 16. Date of Modification (if any): N/A
17. Manufacturer and Model Number:	SCR1 - Haldor Topsoe, CAT1 - Johnson Matthey
18. ID(s) of Emission Unit Controlled:	SCR1, CAT1
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency				2 ppm	2 ppm	2 ppm

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	7,884 HR/YR
23.	Maximum Operation:	7,884 HR/YR

REQUESTED LIMITS

24. Are you requesting any permit limits? ☐ Yes ☒ No (If Yes, indicate all that apply below)

- ☐ Operation Hour Limit(s):
- ☐ Production Limit(s):
- ☐ Material Usage Limit(s):
- ☐ Limits Based on Stack Testing: Please attach all relevant stack testing summary reports
- ☐ Other:

25. Rationale for Requesting the Limit(s): N/A

DEQ AIR QUALITY PROGRAM
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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Idaho Power Company	Langley Gulch Power Plant	075-00012

4. Brief Project Description: Combined Cycle Power Plant

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STORAGE SILOS
6.	EU ID Number:	SILO1
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #:P-2009.0092 Date Issued: 6/25/10
8.	Manufacturer:	PITTSBURGH TANK CORPORATION
9.	Model:	63'
10..	Maximum Capacity:	6,500 CU FT
11.	Date of Construction:	2010
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Bin Vent Filter
15. Date of Installation:	2010 16. Date of Modification (if any): N/A
17. Manufacturer and Model Number:	Dantherm - Silosafe 24
18. ID(s) of Emission Unit Controlled:	SILO1
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	0.01					

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	
23.	Maximum Operation:	2 HR/DAY, 48 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	2 HR/DAY, 48 HR/YR
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	MAXIMUM MODELED EMISSIONS

DEQ AIR QUALITY PROGRAM
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Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Idaho Power Company	Langley Gulch Power Plant	075-00012

4. Brief Project Description: Combined Cycle Power Plant

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5.	Emissions Unit (EU) Name:	STORAGE SILO
6.	EU ID Number:	SILO2
7.	EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source – Previous Permit #:P-2009.0092 Date Issued: 6/25/10
8.	Manufacturer:	PITTSBURGH TANK CORPORATION
9.	Model:	36'
10..	Maximum Capacity:	2,090 CU FT
11.	Date of Construction:	2010
12.	Date of Modification (if any):	N/A
13.	Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Bin Vent Filter
15. Date of Installation:	2010 16. Date of Modification (if any): N/A
17. Manufacturer and Model Number:	Dantherm - Silosafe 24
18. ID(s) of Emission Unit Controlled:	SILO2
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	0.01					

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22.	Actual Operation:	
23.	Maximum Operation:	2 HR/DAY, 48 HR/YR

REQUESTED LIMITS

24.	Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
	☒ Operation Hour Limit(s):	2 HR/DAY, 48 HR/YR
	☐ Production Limit(s):	
	☐ Material Usage Limit(s):	
	☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
	☐ Other:	
25.	Rationale for Requesting the Limit(s):	MAXIMUM MODELED EMISSIONS

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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Unit - General **Form EU0**
Revision 4
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Idaho Power Company	Langley Gulch Power Plant	075-00012

4. Brief Project Description: Combined Cycle Power Plant

EMISSIONS UNIT (PROCESS) IDENTIFICATION & DESCRIPTION

5. Emissions Unit (EU) Name:	STORAGE SILO
6. EU ID Number:	SILO3
7. EU Type:	☐ New Source ☐ Unpermitted Existing Source ☒ Modification to a Permitted Source -- Previous Permit #:P-2009.0092 Date Issued: 6/25/10
8. Manufacturer:	PITTSBURGH TANK CORPORATION
9. Model:	39'
10.. Maximum Capacity:	2,200 CU FT
11. Date of Construction:	2010
12. Date of Modification (if any):	N/A
13. Is this a Controlled Emission Unit?	☐ No ☒ Yes If Yes, complete the following section. If No, go to line 22.

EMISSIONS CONTROL EQUIPMENT

14. Control Equipment Name and ID:	Bin Vent Filter
15. Date of Installation:	2010 16. Date of Modification (if any): N/A
17. Manufacturer and Model Number:	Dantherm - Silosafe 24
18. ID(s) of Emission Unit Controlled:	SILO3
19. Is operating schedule different than emission units(s) involved?	☐ Yes ☒ No
20. Does the manufacturer guarantee the control efficiency of the control equipment?	☒ Yes ☐ No (If Yes, attach and label manufacturer guarantee)

	Pollutant Controlled					
	PM	PM10	SO_2	NOx	VOC	CO
Control Efficiency	0.01					

21. If manufacturer's data is not available, attach a separate sheet of paper to provide the control equipment design specifications and performance data to support the above mentioned control efficiency.

EMISSION UNIT OPERATING SCHEDULE (hours/day, hours/year, or other)

22. Actual Operation:	
23. Maximum Operation:	2 HR/DAY, 48 HR/YR

REQUESTED LIMITS

24. Are you requesting any permit limits?	☒ Yes ☐ No (If Yes, indicate all that apply below)
☒ Operation Hour Limit(s):	2 HR/DAY, 48 HR/YR
☐ Production Limit(s):	
☐ Material Usage Limit(s):	
☐ Limits Based on Stack Testing:	Please attach all relevant stack testing summary reports
☐ Other:	
25. Rationale for Requesting the Limit(s):	MAXIMUM MODELED EMISSIONS

DEQ AIR QUALITY PROGRAM
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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Industrial Engine Information **Form EU1**
Revision 8
1/15/10

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name: Idaho Power Company	2. Facility Name: Langley Gulch Power Plant	075-00012
3 Brief Project Description:	Combined Cycle Power Plant	

ENGINE (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

4. Type of Unit:	☐ New Unit ☐ Unpermitted Existing Unit ☒ Modification to a Unit with Permit #:P-2009.0092 Date Issued: 06/25/2010		
5. Engine Displacement:	2.25 (liters per cylinder)	6. Ignition Type:	☒ Compression ☐ Spark
7. Use	☒ Emergency ☐ Non-Emergency		
8. Engine ID Number: EG1	9. Maximum Rated Engine Power: _____ Brake Horsepower (bhp)		
10. Construction Date: 2011	11. Manufacturer: Caterpillar	12. Model: C27	13. Model Year: 2011
14. Date of Modification (if applicable): N/A	15. Serial Number (if available): MJE02809	16. Control Device (if any): N/A	

FUEL DESCRIPTION AND SPECIFICATIONS

17. Fuel Type	☒ Diesel Fuel (#2) (gal/hr)	☐ Gasoline Fuel (gal/hr)	☐ Natural Gas (cf/hr)	☐ Other Fuels (unit:)
18. Full Load Consumption Rate	53.6			
19. Actual Consumption Rate	53.6			
20. Sulfur Content wt%	0.0015	N/A	N/A	

OPERATING LIMITS & SCHEDULE

21. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):
4 hr/day, 60 hr/yr

22. Operating Schedule (hours/day, months/year, etc.):
4 hr/day, 1-2 days/month, 12 months/yr

DEQ AIR QUALITY PROGRAM
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Emissions Units - Industrial Engine Information **Form EU1**
Revision 8
1/15/10

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name: Idaho Power Company	2. Facility Name: Langley Gulch Power Plant	075-00012
3 Brief Project Description:	Combined Cycle Power Plant	

ENGINE (EMISSION UNIT) DESCRIPTION AND SPECIFICATIONS

4. Type of Unit:	☐ New Unit ☐ Unpermitted Existing Unit ☒ Modification to a Unit with Permit #:P-2009.0092 Date Issued: 06/25/2010		
5. Engine Displacement:	1.5 (liters per cylinder)	6. Ignition Type:	☒ Compression ☐ Spark
7. Use	☒ Emergency ☐ Non-Emergency		
8. Engine ID Number: FP1	9. Maximum Rated Engine Power: _____ Brake Horsepower (bhp)		
10. Construction Date: 2010	11. Manufacturer: Cummins	12. Model: CFP9E-F30	13. Model Year: 2010
14. Date of Modification (if applicable): N/A	15. Serial Number (if available): 73161742	16. Control Device (if any): N/A	

FUEL DESCRIPTION AND SPECIFICATIONS

17. Fuel Type	☒ Diesel Fuel (#2) (gal/hr)	☐ Gasoline Fuel (gal/hr)	☐ Natural Gas (cf/hr)	☐ Other Fuels (unit:)
18. Full Load Consumption Rate	15.8			
19. Actual Consumption Rate	15.8			
20. Sulfur Content wt%	0.0015	N/A	N/A	

OPERATING LIMITS & SCHEDULE

21. Imposed Operating Limits (hours/year, or gallons fuel/year, etc.):
1 hr/day, 30 hr/yr

22. Operating Schedule (hours/day, months/year, etc.):
1 hr/day, 30 hr/yr

DEQ AIR QUALITY PROGRAM
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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Emissions Units - Cooling Towers Information **Form EU4**
Revision 5
08/28/08

Please see instructions on page 2 before filling out the form.

IDENTIFICATION

1. Company Name:	2. Facility Name:	3. Facility ID No:
Idaho Power Company	Langley Gulch Power Plant	075-00012

4. Brief Project Description: Combined Cycle Power Plant

COOLING TOWER IDENTIFICATION AND DESCRIPTION

	Tower 1	Tower 2	Tower 3	Tower 4
5. Emission Unit Name	Cooling Tower			
6. Emission Unit ID Number	Tower1			
7. Stack/Vent ID Number	Tower1			
8. Tower Type (N: New, U: Unpermitted, M: Modification)	☒ N, ☐ U, ☐ M	☐ N, ☐ U, ☐ M	☐ N, ☐ U, ☐ M	☐ N, ☐ U, ☐ M
9. Current Permit Number	P-2009.0092			
10. Tower Construction Date	2010			
11. Tower Manufacturer	GEA			
12. Tower Model Number	485436-7I-33-FCF			
13. Number of Cells in Tower	7			
14. Tower Maximum Water Flow Rate	63,200 gpm			
15. Measured TDS Content (if known)	5,000			
16. Do you use additives in the water? If Yes, provide an MSDS form for each additive	☐ No ☒ Yes	☐ No ☐ Yes	☐ No ☐ Yes	☐ No ☐ Yes

CONTROL EQUIPMENT INFORMATION

17. Control Equipment	☐ No ☒ Yes	☐ No ☐ Yes	☐ No ☐ Yes	☐ No ☐ Yes
18. Control Equipment ID Number	Drift Eliminator			
19. Control Equipment Efficiency	0.0005%			

OPERATING SCHEDULE

20. Actual Operation (hours per year)	8,760			
21. Maximum Operation (hours per year)	8,760			

REQUEST FOR PERMIT LIMITATIONS

22 Are you requesting any permit limits? ☐ No ☒ Yes. If Yes, fill in all that apply below.

Tower Served	Operation Hour Limits:	TDS Limits (ppm):	Material Usage Limits:	Other:
Tower 1		5,000		
Tower 2				
Tower 3				
Tower 4				

23. Rationale for Requesting the Limit(s): Maximum Modeled Concentration

DEQ AIR QUALITY PROGRAM
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For assistance, call the
Air Permit Hotline – 1-877-5PERMIT

Afterburner/Oxidizer - **Form AO**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

1. Company Name: Idaho Power Company	2. Facility Name: Langley Gulch Power Plant	3. Facility ID No.: 075-00012
4. Brief Project Description: Combined Cycle Power Plant		

AFTERBURNER/OXIDIZER INFORMATION

Equipment Description

5. Manufacturer: Haldor Topsoe	6. Model Number: DeNOx DNX-929	
7. Type	☐ Catalytic oxidizer ☐ Recuperative oxidizer ☐ Thermal (direct fired) oxidizer ☐ Regenerative thermal oxidizer (RTO) Number of chambers: Is a rotoconcentrator for VOC part of the design? ☐ Yes ☐ No	Media type for regenerative oxidizer: ☐ Saddles ☐ Monolith ☐ Other: For recuperative oxidizer, type of heat exchanger: ☐ Shell and tube ☐ Plate ☐ Other:
8. Type of Burner	☒ Gas fired Btu rating: 2,375,000,000 ☐ Electric KW rating: ☐ Oil fired Btu rating:	Blower scfm: Blower hp: Manufacturer's emission guarantee for burners for: NOx: 2 ppm @15 % O_2 CO: ppm @ % O_2
9. Design Criteria	Retention time at normal operating temperature: seconds at degrees F Combustion chamber volume: cubic feet (ft^3) Design gas flow: 856,816 scfm	
10. Pre-Treatment	Is a pre-treatment device for particulate removal present? ☐ Yes ☒ No If yes, indicate type: ☐ Cyclone ☐ Precooler ☐ Preheater ☐ Knock-out chamber ☐ Baghouse ☐ Other:	
11. Auxiliary Fuel Data	Auxiliary fuel available? ☐ Yes ☒ No If yes, indicate type:	Fuel usage (check one): Maximum Minimum Average ☐ Cubic feet (ft^3)/hour ☐ Gallons/hour
12. For Catalytic Oxidizer	Catalyst manufacturer:	
	Type of catalyst: ☐ Low temperature catalyst ☐ Commercial noble metal ☒ Other: V205 Honeycomb Estimated catalyst life:3 years Catalyst cleaning frequency:As Necessary months Method of cleaning:Vacuuming	Does the process emit any of the following potential catalyst masking agents or deactivators? ☒ Yes (if yes, check type[s] below) ☐ No ☐ Halogen ☐ Heavy metal ☐ Silicone ☒ Sulfur compounds ☐ Phosphorus compound ☒ Particulate matter
13. Process Blower	Blower: 100 hp Design flow rate: 3500 scfm Draft: ☒ Forced ☐ Induced	

Process Stream Characteristics

14. Brief Description of Process

Selective Catalytic Reduction System (SCR). The SCR system resides in the same duct as the CO catalyst and is used to reduce levels of NOx from the flue gas. The NOx reduction is achieved by reacting NOx with ammonia to form elemental nitrogen and water vapor. The ammonia is injected into the flue gas stream and passing the mixture over a honeycomb style Vanadium catalyst. The SCR system consists of the three primary components: the Ammonia Flow Control Unit Skid (AFCU), the Ammonia Injection Grid (AIG) and the SCR catalyst. The AFCU (blower information shown in line item 13) takes aqueous ammonia and vaporizes the ammonia before forwarding it to the AIG. The AIG is a series of gas sparging lances running through the duct work to allow for even distribution of the ammonia into the flue gas. The ammonia/flue gas mixture passes through the catalyst where the reduction reaction takes place. A small amount of the injected ammonia passes through the catalyst unreacted and exits through the stack as ammonia slip.

15. Emission Data

Air contaminant	Concentration ppmv	Destruction efficiency %
NOx	2 ppm vdc @ 15% O2	93% at guarantee case
Ammonia Slip	5 ppm vdc @ 15% O2	n/a

16. Instrumentation Data

Temperature is measured in the duct both upstream of the SCR catalyst and at the exit of the boiler stack.
Temperature measurements on the AFCU skid are taken at the inlet and outlet of the ammonia vaporizer.
Pressure drop across the SCR catalyst is measured by DP transmitters.
Flow measurement of ammonia is made on the AFCU skid before the vaporizer.
Outlet NOx is measured through CEMS equipment installed in the outlet stack.

17. Bakeout Process

Is bakeout a feature of the process? ☐ Yes ☒ No

18. Operating Conditions

	Maximum	Minimum	Average
Operating temperature (degrees F):	693	400	590
Exit gas temperature (degrees F):	693	400	590
Pressure inches (H_2O):	15.67	6	10.99
Moisture content (%):	18.02	6.02	9
Gas volume (scfm):	856,816	526,168	720,539
Gas velocity (duct-ft/min):	603	370	507

19. Operating Schedule

Normal:	hours/day	days/week	47 weeks/year
Maximum:	hours/day	days/week	52 weeks/year

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Afterburner/Oxidizer - **Form AO**
Revision 2
08/28/08

Please see instructions on page 3 before filling out the form.

IDENTIFICATION

1. Company Name: Idaho Power Company	2. Facility Name: Langley Gulch Power Plant	3. Facility ID No.: 075-00012
4. Brief Project Description: Combined Cycle Power Plant		

AFTERBURNER/OXIDIZER INFORMATION

Equipment Description

5. Manufacturer: Johnson Matthey	6. Model Number: K11535	
7. Type	☒ Catalytic oxidizer ☐ Recuperative oxidizer ☐ Thermal (direct fired) oxidizer ☐ Regenerative thermal oxidizer (RTO) Number of chambers: Is a rotoconcentrator for VOC part of the design? ☐ Yes ☐ No	Media type for regenerative oxidizer: ☐ Saddles ☐ Monolith ☐ Other: For recuperative oxidizer, type of heat exchanger: ☐ Shell and tube ☐ Plate ☐ Other:
8. Type of Burner	☒ Gas fired Btu rating: 2,375,000,000 ☐ Electric KW rating: ☐ Oil fired Btu rating:	Blower scfm: Blower hp: Manufacturer's emission guarantee for burners for: NOx: ppm @ % O_2 CO: 2 ppm @ 15 % O_2
9. Design Criteria	Retention time at normal operating temperature: seconds at degrees F Combustion chamber volume: cubic feet (ft^3) Design gas flow: 856,816 scfm	
10. Pre-Treatment	Is a pre-treatment device for particulate removal present? ☐ Yes ☒ No If yes, indicate type: ☐ Cyclone ☐ Precooler ☐ Preheater ☐ Knock-out chamber ☐ Baghouse ☐ Other:	
11. Auxiliary Fuel Data	Auxiliary fuel available? ☐ Yes ☒ No If yes, indicate type:	Fuel usage (check one): Maximum Minimum Average ☐ Cubic feet (ft^3)/hour ☐ Gallons/hour
12. For Catalytic Oxidizer	Catalyst manufacturer: Johnson Matthey Type of catalyst: ☐ Low temperature catalyst ☒ Commercial noble metal ☐ Other: Estimated catalyst life:3 years Catalyst cleaning frequency:As Necessary months Method of cleaning:Vacuuming	Does the process emit any of the following potential catalyst masking agents or deactivators? ☒ Yes (if yes, check type[s] below) ☐ No ☐ Halogen ☐ Heavy metal ☐ Silicone ☒ Sulfur compounds ☐ Phosphorus compound ☒ Particulate matter
13. Process Blower	Blower: hp Design flow rate: scfm Draft: ☐ Forced ☐ Induced	

Process Stream Characteristics

14. Brief Description of Process	CO Oxidizing Catalyst. The CO removal systems consists of a noble metal catalyst (Pt or Pd active material) which oxidizes CO and VOCs to CO2. The catalyst resides in the boiler duct and requires no auxiliary equipment to operate.

15. Emission Data

Air contaminant	Concentration ppmv	Destruction efficiency %
CO	2 ppm vdc @15% O2	50% at guarantee case

16. Instrumentation Data	Pressure drop across the CO catalyst is measured by DP transmitters. Outlet CO is measured through CEMS equipment installed in the outlet stack.
17. Bakeout Process	Is bakeout a feature of the process? ☐ Yes ☒ No

18. Operating Conditions

	Maximum	Minimum	Average
Operating temperature (degrees F):	693	400	641
Exit gas temperature (degrees F):	693	400	641
Pressure inches (H_2O):	15.67	6	10.99
Moisture content (%):	18.02	6.02	9
Gas volume (scfm):	856,816	526,168	720,539
Gas velocity (duct-ft/min):	603	370	507

19. Operating Schedule

Normal:	hours/day	days/week	47 weeks/year
Maximum:	hours/day	days/week	52 weeks/year

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Version 1, August 2010

Facility Wide Potential to Emit Emission Inventory

Application Template and Instructions

For new stationary sources provide the facility's potential to emit for all NSR Regulated Air Pollutants. The potential to emit provided here must match the emissions rates which are requested to be permitted.

For modifications to existing facilities (including the addition of new emissions units), if the existing facility classification is in question an existing facility wide potential to emit emission inventory will be required to be submitted[1]. Contact DEQ to determine if a facility wide emission inventory for the existing facility is required.

All emissions inventories must be submitted with thorough documentation. The emission inventories will be subjected to technical review. Therefore, prepare your application with sufficient documentation so that the public and DEQ can verify the validity of the emission estimates. **Applications submitted without sufficient documentation are incomplete. Follow the instructions provided on page 2; do not proceed until you have read the instructions.**

Applicants must use the Potential to Emit Summary table provided below.

Table 1. POTENTIAL TO EMIT FOR NSR REGULATED POLLUTANTS

Emissions Unit	PM-10	CO	NOx	VOC	SO2	CO2e
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Point Sources						
HRSG	48.1	278.1	87.7	74.9	12.5	1,092,050
Fire Pump (FP1)	.00	.03	.03	.00	.00	8.9
Emergency Generator (EG1)	.01	.19	.35	.02	.00	36.2
Cooling Tower (CELL1-CELL7)	2.9					
Chemical Silos (SILO1 – SILO3)	.01					
Fugitive Sources *{For listed source categories only, see item 3 below in the instructions}*						
Paved Roads	.001					
Unpaved Roads	.002					
Totals	**51.0**	**278.3**	**88.1**	**74.9**	**12.5**	**1,093,129.8**

a) NSR Regulated air Pollutants are defined[2] as: Particulate Matter (PM, PM-10, PM-2.5), Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone (VOC), Sulfur Dioxide, CO_2e[3], Green House Gases (GHG) mass, all pollutants regulated by

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[1] The applicant must determine if the existing facility is a major facility. If the facility is an existing PSD major facility and changes are being made to the facility the major modification test must be conducted.

[2] 40 CFR 52.21(b)(50), as incorporated by reference at IDAPA 58.01.01.107.03.d

[3] Multiply each green house gas (GHG) by the global warming potential (GWP) listed at 40 CFR 98, Table A- 1 of Subpart A then sum all values to determine CO_2e (GHGs are carbon dioxide, nitrous oxide, methane, hydrofluorcarbons, perfluorcarbons, sulfur hexafluoride). Be sure to show all calculations as described in the instructions.

NSPS (40 CFR 60)(i.e. TRS, fluoride, sulfuric acid mist) & Class I & Class II Ozone Depleting Substances (40 CFR 82)(i.e. CFC, HCFC, Halon, etc.)

Applicants are encouraged to call DEQ's Air Quality Permit Hotline (1-877-573-7648) to ask questions as they prepare the application.**Emission Inventory Instructions:**

1. Use the same emission unit name throughout the application (i.e. in air pollution control equipment forms and for modeling purposes).

2. The application must **show in detail all calculations** used to develop the PTE summary and include:

   - Electronic copies of any spreadsheets used to estimate emissions. If a spreadsheet is used submit an electronic copy of the spread sheet (i.e. Excel File).
   - Documentation of all calculations conducted by hand (i.e. show all calculations).
   - Clear statements on all assumptions relied upon in estimating emissions.
   - Documentation of the emissions factors used to estimate emissions. If the emissions factor documentation is readily available to DEQ, such as an EPA AP-42 emissions factor, a simple reference to the emissions factor suffices. If the emissions factor documentation is not readily available to DEQ the applicant must submit the documentation with the application; ask DEQ if you are uncertain. **Applications without sufficient documentation are incomplete.** Documentation may consist of manufacturer guarantees, research conducted by trade organizations, published emission factors, and source test results. **If there are multiple factors for a given operation, note why the factor used is the most representative.**
   - Copies of manufacturer guarantees upon which emission inventories are based.
   - The best available emission information (see DEQ's Guidance on Emission Data Hierarchy).
   - If source tests are used as the basis for emissions estimates the source test report must be submitted. If the source test report is on file with DEQ provide the date of the source test was submitted along with the name of the facility and the emission unit that was tested. Source data from similar emissions units may be considered reliable provided it is clearly described why the sources are similar. Similar sources are those that the applicant has shown serve a similar function, use similar raw materials, and have similar processing rates.

3. Fugitive emissions of NSR regulated air pollutants from the source categories listed below must be included in the emission inventory.

Listed Source Categories for Inclusion of Fugitive Emissions

- Coal cleaning plants (with thermal dryers)
- Kraft pulp mills
- Portland cement plants
- Primary zinc smelters
- Iron and steel mills
- Primary aluminum ore reduction plants
- Primary copper smelters
- Municipal incinerators -250 T/day of refuse
- Hydrofluoric, sulfuric, or nitric acid plants
- Petroleum refineries
- Lime plants
- Phosphate rock processing plants
- Coke oven batteries
- Sulfur recovery plants
- Carbon black plants (furnace process)
- Primary lead smelters
- Fuel conversion plants
- Sintering plants
- Secondary metal production plants
- Chemical process plants (excluding ethanol plants by natural fermentation).
- Fossil-fuel fired boilers totaling more than 250 MMBtu/hr
- Petroleum storage and transfer units with total capacity of 300,000 barrels
- Taconite ore processing plants
- Glass fiber processing plants
- Charcoal production plants
- Fossil fuel-fired steam electric plants greater than 250 MMBtu/hr)
- Categories regulated by NSPS or NESHAP prior to 8/7/80

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

Version 1, August 2010

Facility Wide Hazardous Air Pollutant Potential to Emit
Application Template and Instructions

Provide the facility wide potential to emit for all Hazardous Air Pollutants (HAPs). **The potential to emit provided here must match the emissions rates which are requested to be permitted.**

HAPs are pollutants that are required to be regulated under the Clean Air Act. A list of the HAPs may be found by following this link: HAP list; review the list carefully to be sure you have included all listed HAPs.

All emissions inventories must be submitted with thorough documentation. The emission inventories will be subjected to technical review; prepare your application with sufficient documentation so that either the public or DEQ can verify the validity of the emission estimates. **Applications submitted without sufficient documentation are incomplete. Follow the instructions provided on the following page; do not proceed until you have read the instructions.**

Applicants must use the Potential to Emit Summary table provided below. Identify the individual HAP with the highest emissions and total HAP emissions. The potential to emit provided here must match the emissions rates which are requested to be permitted. **All fugitive emissions of HAPs must be included.**

Table X HAP POTENTIAL TO EMIT EMISSIONS SUMMARY

HAP Pollutants	PTE (T/yr)
1,3-Butadiene	**3.62e-3**
Acetaldehyde	**3.37e-1**
Acrolein	**5.38e-2**
Arsenic	**1.85e-4**
Benzene	**1.03e-1**
Beryllium	**1.11e-5**
Cadmium	**1.02e-3**
Chromium	**1.29e-3**
Cobalt	**7.76e-5**
Dichlorobenzene	**1.11e-3**
Ethyl Benzene	**2.69e-1**
Formaldehyde*	**6.04**
Hexane	**1.66**
Manganese	**3.51e-4**
Mercury	**2.40e-4**
Naphthalene	**1.15e-2**
Nickel	**1.94e-3**
Propylene Oxide	**2.44e-1**
POM	**1.56e-5**
Selenium	**2.22e-5**
Toluene	**1.10**
Xylenes	**5.38e-1**
Total	**10.37**

* Maximum Individual HAP

Applicants are encouraged to call DEQ's Air Quality Permit Hotline (1-877-573-7648) to ask questions as they prepare the application.

Emission Inventory Instructions:

1. Use the same emission unit name throughout the application (i.e. in air pollution control equipment forms and for modeling purposes).

2. The application must **show in detail all calculations** used to develop the PTE summary and include:

   - Electronic copies of any spreadsheets used to estimate emissions. If a spreadsheet is used submit an electronic copy of the spread sheet (i.e. Excel File).
   - Documentation of all calculations conducted by hand (i.e. show all calculations).
   - Clear statements on all assumptions relied upon in estimating emissions.
   - Documentation of the emissions factors used to estimate emissions. If the emissions factor documentation is readily available to DEQ, such as an EPA AP-42 emissions factor, a simple reference to the emissions factor suffices. If the emissions factor documentation is not readily available to DEQ the applicant must submit the documentation with the application; ask DEQ if you are uncertain. **Applications without sufficient documentation are incomplete.** Documentation may consist of manufacturer guarantees, research conducted by trade organizations, published emission factors, and source test results. **If there are multiple factors for a given operation, note why the factor used is the most representative.**
   - Copies of manufacturer guarantees upon which emission inventories are based.

- The best available emission information (see DEQ's Guidance on Emissions Data Hierarchy).
- If source tests are used as the basis for emissions estimates the source test report must be submitted. If the source test report is on file with DEQ provide the date of the source test was submitted along with the name of the facility and the emission unit that was tested. Source data from similar emissions units may be considered reliable provided it is clearly described why the sources are similar. Similar sources are those that the applicant has shown serve a similar function, use similar raw materials, and have similar processing rates.

2. **All fugitive emissions of HAPs must be included[1].**

[1] November 27, 2001 (66 FR 59161), EPA published a rule, "Change to Definition of Major Source," that requires the fugitive emissions of all hazardous air pollutants ("HAPs") listed under section 112(b) of the Act in determining whether the source is a major source.

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For assistance, call the
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Compliance Assurance Monitoring - **Form CAM**
Revision 2
08/28/08

Please see instructions on pages 3-8 before filling out the form.

IDENTIFICATION

1. Company Name: Idaho Power Company	2. Facility Name: Langley Gulch Power Plant	3. Facility ID No.: 075-00012
4. Brief Project Description: Combined Cycle Power Plant		

MONITORING APPROACH SUBMITTAL

Background

5. Emissions Unit	Description (type of emission point): Combustion Turbine with Heat Recovery Steam Generator	Identification (emission point number): HRSG
6. Applicable Regulation, Emission Limits, and Monitoring Requirements	Applicable regulation citation: 40 CFR 51.21; Prevention of Significant Deterioration 40 CFR 75; Continuous Emissions Monitoring	Pollutant: NOx Emission limit: 2 ppm @ 15% O2 Pollutant: CO Emission limit: 2 ppm @ 15% O2 Pollutant: Emission limit: Monitoring requirements: Continuous Emissions Monitoring System (CEMS); 40 CFR 75
7. Control Technology	Brief description: Dry Low NOx Burners, Selective Catalytic Reduction, Oxidation Catalyst	

Table 1. Monitoring Approach

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator Description	See Justification		
Measurement Approach			
II. Indicator Range (Quality improvement plan threshold optional)			
III. Performance Criteria	—	—	—
A. Data Representativeness			
B. Verification of Operational Status			
C. QA/QC Practices and Criteria			
D. Monitoring Frequency			
Data Collection Procedures			
Averaging Period			

Justification	Present justification for selection of monitoring approach(es) and indicator range(s): Justification for Indicator 1: In accordance with 40 CFR 64.3(d), the CEMS satifies the requirements of 40 CFR 64. No further measurement necessary under CAM. Justification for Indicator 2: Justification for Indicator 3:

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AIR PERMIT APPLICATION

Revision 6
10/7/09

For each box in the table below, CTRL+click on the blue underlined text for instructions and information.

IDENTIFICATION	
1. Company Name: Idaho Power Company	2. Facility Name: Langley Gulch Power Plant
3. Brief Project Description: Combined Cycle Power Plant	

APPLICABILITY DETERMINATION	
4. List applicable subparts of the New Source Performance Standards (NSPS) (40 CFR part 60). Examples of NSPS affected emissions units include internal combustion engines, boilers, turbines, etc. The applicant must thoroughly review the list of affected emissions units.	List of applicable subpart(s): 40 CFR 60, Subpart A 40 CFR 60, Subpart IIII 40 CFR 60, Subpart KKKK ☐ Not Applicable
5. List applicable subpart(s) of the National Emission Standards for Hazardous Air Pollutants (NESHAP) found in 40 CFR part 61 and 40 CFR part 63. Examples of affected emission units include solvent cleaning operations, industrial cooling towers, paint stripping and miscellaneous surface coating. EPA has a web page dedicated to NESHAP that should be useful to applicants.	List of applicable subpart(s): 40 CFR 63, Subpart A 40 CFR 63, Subpart ZZZZ ☐ Not Applicable
6. For each subpart identified above, conduct a complete a regulatory analysis using the instructions and referencing the example provided on the following pages. **Note** - Regulatory reviews must be submitted with sufficient detail so that DEQ can verify applicability and document in legal terms why the regulation applies. Regulatory reviews that are submitted with insufficient detail will be determined incomplete.	☑ A detailed regulatory review is provided (Follow instructions and example). ☑ DEQ has already been provided a detailed regulatory review. Give a reference to the document including the date.

IF YOU ARE UNSURE HOW TO ANSWER ANY OF THESE QUESTIONS, CALL THE AIR PERMIT HOTLINE AT 1-877-5PERMIT

It is emphasized that it is the applicant's responsibility to satisfy all technical and regulatory requirements, and that DEQ will help the applicant understand what those requirements are prior to the application being submitted but that DEQ will not perform the required technical or regulatory analysis on the applicant's behalf.

Appendix B

Detailed Emission Calculations

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Combustion Turbine & Duct Burner (Maximum Emission Case)

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	2,375	Vendor Information
Fuel Heating Value	[Btu/ft^3]	994	PTC Application
F-Factor	[dscf/MMBtu]	8,710	40 CFR 75, Appendix F, Table 1
Ideal Gas Density	[scf/lb-mol]	335.6	

NOx

NOx Concentration	[ppm]	2	PTC Limit, BACT
NOx Molecular Weight	[lb/lb-mol]	46.01	
NOx Startup & Shutdown	[tons/yr]	18.4	PTC Application

$$NOx[\frac{lb}{hr}] = \frac{NOx[ppm] * NOx[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

NOx Emission Rate	[lb/hr]	20.1

$$NOx\left[\frac{ton}{yr}\right] = \frac{NOx\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + NOx\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

NOx Emissions	[ton/yr]	87.7

CO

CO Concentration	[ppm]	2	PTC Limit, BACT
CO Molecular Weight	[lb/lb-mol]	28.01	
CO Startup & Shutdown	[tons/yr]	235.9	PTC Application

$$CO[\frac{lb}{hr}] = \frac{CO[ppm] * CO[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

CO Emission Rate	[lb/hr]	12.2

$$CO\left[\frac{ton}{yr}\right] = \frac{CO\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + CO\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

CO Emissions	[ton/yr]	278.1

VOC

VOC Concentration	[ppm]	2	PTC Limit, BACT
VOC Molecular Weight	[lb/lb-mol]	16.04	
VOC Startup & Shutdown	[tons/yr]	50.7	PTC Application

$$VOC[\frac{lb}{hr}] = \frac{VOC[ppm] * VOC[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

VOC Emission Rate	[lb/hr]	7.0

$$VOC\left[\frac{ton}{yr}\right] = \frac{VOC\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + VOC\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

VOC Emissions	[ton/yr]	74.9

SO2

SO2 Concentration	[gr/hscf]	0.5	40 CFR 72.2; "Pipeline Natural Gas" Definition
SO2 Molecular Weight	[lb/lb-mol]	64.04	
S Molecular Weight	[lb/lb-mol]	32.07	
SO2 Startup & Shutdown	[tons/yr]	0.7	PTC Application

$$SO2\left[\frac{lb}{hr}\right] = \frac{Fuel\ Flow\left[\frac{100scf}{hr}\right] * Sulfur\ Content\left[\frac{gr}{100scf}\right]}{7000[\frac{gr}{lb}]} * \frac{SO2[MW]}{S[MW]}$$

SO2 Emission Rate	[lb/hr]	3.4

$$SO2\left[\frac{ton}{yr}\right] = \frac{SO2\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + SO2\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

SO2 Emissions	[ton/yr]	12.5

PM-10

PM-10 Concentration	[lb/hr]	12.55	PTC Limit; Vendor Guarantee
PM-10 Startup & Shutdowr	[tons/yr]	5.2	PTC Application

PM-10 Emission Rate	[lb/hr]	12.6

$$PM10\left[\frac{ton}{yr}\right] = \frac{PM10\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + PM10\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

PM-10 Emissions	[ton/yr]	48.5

CO2

CO2 Emission Factor [kg/MMBtu] 53.02 40 CFR 98, Table C-1

$$CO_2\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	277,030

$$CO_2\left[\frac{ton}{yr}\right] = \frac{CO_2\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	1,092,050

CH4

CH4 Emission Factor [kg/MMBtu] 1.00E-03 40 CFR 98, Table C-1

$$CH_4\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	5.2

$$CH_4\left[\frac{ton}{yr}\right] = \frac{CH_4\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	20.6

N2O

N2O Emission Factor [kg/MMBtu] 1.00E-04 40 CFR 98, Table C-1

$$N_2O\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	0.5

$$N_2O\left[\frac{ton}{yr}\right] = \frac{N_2O\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	2.1

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Combustion Turbine & Duct Burner (Maximum Emission Case)

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	2,375	Vendor Information
Fuel Heating Value	[Btu/ft^3]	994	PTC Application
F-Factor	[dscf/MMBtu]	8,710	40 CFR 75, Appendix F, Table 1
Ideal Gas Density	[scf/lb-mol]	335.6	

NOx

NOx Concentration	[ppm]	2	PTC Limit, BACT
NOx Molecular Weight	[lb/lb-mol]	46.01	
NOx Startup & Shutdown	[tons/yr]	18.4	PTC Application

$$NOx\left[\frac{lb}{hr}\right] = \frac{NOx[ppm] * NOx[MW] * FFactor\left[\frac{dscf}{MMBtu}\right] * Fuel\ Flow\left[\frac{MMBtu}{hr}\right]}{10^6 * 335.6} * \left(\frac{20.9}{20.9 - 15}\right)$$

NOx Emission Rate	[lb/hr]	20.1

$$NOx\left[\frac{ton}{yr}\right] = \frac{NOx\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + NOx\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

NOx Emissions	[ton/yr]	87.7

CO

CO Concentration	[ppm]	2	PTC Limit, BACT
CO Molecular Weight	[lb/lb-mol]	28.01	
CO Startup & Shutdown	[tons/yr]	235.9	PTC Application

$$CO\left[\frac{lb}{hr}\right] = \frac{CO[ppm] * CO[MW] * FFactor\left[\frac{dscf}{MMBtu}\right] * Fuel\ Flow\left[\frac{MMBtu}{hr}\right]}{10^6 * 335.6} * \left(\frac{20.9}{20.9 - 15}\right)$$

CO Emission Rate	[lb/hr]	12.2

$$CO\left[\frac{ton}{yr}\right] = \frac{CO\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + CO\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

CO Emissions	[ton/yr]	278.1

VOC

VOC Concentration	[ppm]	2	PTC Limit, BACT
VOC Molecular Weight	[lb/lb-mol]	16.04	
VOC Startup & Shutdown	[tons/yr]	50.7	PTC Application

$$VOC[\frac{lb}{hr}] = \frac{VOC[ppm] * VOC[MW] * FFactor[\frac{dscf}{MMBtu}] * Fuel\ Flow[\frac{MMBtu}{hr}]}{10^6 * 335.6} * (\frac{20.9}{20.9 - 15})$$

VOC Emission Rate	[lb/hr]	7.0

$$VOC\left[\frac{ton}{yr}\right] = \frac{VOC\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + VOC\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

VOC Emissions	[ton/yr]	74.9

SO2

SO2 Concentration	[gr/hscf]	0.5	40 CFR 72.2; "Pipeline Natural Gas" Definition
SO2 Molecular Weight	[lb/lb-mol]	64.04	
S Molecular Weight	[lb/lb-mol]	32.07	
SO2 Startup & Shutdown	[tons/yr]	0.7	PTC Application

$$SO2\left[\frac{lb}{hr}\right] = \frac{Fuel\ Flow\left[\frac{100scf}{hr}\right] * Sulfur\ Content\left[\frac{gr}{100scf}\right]}{7000[\frac{gr}{lb}]} * \frac{SO2[MW]}{S[MW]}$$

SO2 Emission Rate	[lb/hr]	3.4

$$SO2\left[\frac{ton}{yr}\right] = \frac{SO2\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + SO2\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

SO2 Emissions	[ton/yr]	12.5

PM-10

PM-10 Concentration	[lb/hr]	12.55	PTC Limit; Vendor Guarantee
PM-10 Startup & Shutdowr	[tons/yr]	5.2	PTC Application

PM-10 Emission Rate	[lb/hr]	12.6

$$PM10\left[\frac{ton}{yr}\right] = \frac{PM10\left[\frac{lb}{hr}\right] * 6{,}902\left[\frac{hr}{yr}\right]}{2000\frac{lb}{ton}} + PM10\left[\frac{tons}{Startup\ \&\ Shutdown}\right]$$

PM-10 Emissions	[ton/yr]	48.5

CO2

CO2 Emission Factor [kg/MMBtu] 53.02 40 CFR 98, Table C-1

$$CO_2\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	277,030

$$CO_2\left[\frac{ton}{yr}\right] = \frac{CO_2\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	1,092,050

CH4

CH4 Emission Factor [kg/MMBtu] 1.00E-03 40 CFR 98, Table C-1

$$CH_4\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	5.2

$$CH_4\left[\frac{ton}{yr}\right] = \frac{CH_4\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	20.6

N2O

N2O Emission Factor [kg/MMBtu] 1.00E-04 40 CFR 98, Table C-1

$$N_2O\left[\frac{lb}{hr}\right] = Fuel\ Flow\left[\frac{MMBtu}{hr}\right] * Emission\ Factor\left[\frac{kg}{MMBtu}\right] * 2.2\left[\frac{lb}{kg}\right]$$

CO Emission Rate	[lb/hr]	0.5

$$N_2O\left[\frac{ton}{yr}\right] = \frac{N_2O\left[\frac{lb}{hr}\right] * \left(6{,}902\left[\frac{hr}{yr}\right] + 982\left[\frac{hr}{yr}\right]\right)}{2000\frac{lb}{ton}}$$

CO Emissions	[ton/yr]	2.1

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Emergency Generator

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Engine Rating	[bhp]	1214	Vendor Advertised Maximum hp Rating
Annual Operation	[hrs]	60	PTC Application
Daily Operation	[hrs]	4	PTC Application
Heat Input	[gal/hr]	53.6	Vendor Information
Fuel Heating Value	[Btu/gal]	137,030	AP-42; Chapter 3
Fuel Sulfur Content	[% by weight]	0.0015	Ultra Low Sulfur Diesel (ULSD)

NOx

NOx Emission Factor	[g/hr-hr]	4.8	EPA Tier 2 Standard

$$NOx\left[\frac{lb}{hr}\right] = Rating[hp] * NOx\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

NOx Emission Rate	[lb/hr]	12.8

$$NOx\left[\frac{ton}{yr}\right] = NOx\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

NOx Emissions	[ton/yr]	0.39

CO

CO Emission Factor	[g/hr-hr]	2.6	EPA Tier 2 Standard

$$CO\left[\frac{lb}{hr}\right] = Rating[hp] * CO\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

CO Emission Rate	[lb/hr]	7.0

$$CO\left[\frac{ton}{yr}\right] = CO\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

CO Emissions	[ton/yr]	0.21

VOC

VOC Emission Factor [g/hp-hr] 0.3 EPA Tier 2 Standard (HC Emission Factor)

$$VOC\left[\frac{lb}{hr}\right] = Rating[hp] * VOC\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

VOC Emission Rate	[lb/hr]	0.8

$$VOC\left[\frac{ton}{yr}\right] = VOC\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

VOC Emissions	[ton/yr]	0.02

SO2

SO2 Emission Factor [lb/hp-hr] 0.000012 EPA AP-42, Table 3.4-1

$$SO2\left[\frac{lb}{hr}\right] = Rating[hp] * SO2\ EF\left[\frac{lb}{hp * hr}\right]$$

SO2 Emission Rate	[lb/hr]	0.01

$$SO2\left[\frac{ton}{yr}\right] = SO2\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

SO2 Emissions	[ton/yr]	0.00

PM-10

PM-10 Emission Factor [g/hp-hr] 0.15 EPA Tier 2 Standard

$$PM10\left[\frac{lb}{hr}\right] = Rating[hp] * PM10\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

PM-10 Emission Rate	[lb/hr]	0.4

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

PM-10 Emissions	[ton/yr]	0.01

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Fire Pump Engine

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Engine Rating	[bhp]	305	Vendor Advertised Maximum hp Rating
Annual Operation	[hrs]	30	PTC Application
Daily Operation	[hrs]	1	PTC Application
Heat Input	[gal/hr]	15.8	Vendor Information
Fuel Heating Value	[Btu/gal]	137,030	AP-42; Chapter 3
Fuel Sulfur Content	[% by weight]	0.0015	Ultra Low Sulfur Diesel (ULSD)

NOx

NOx Emission Factor	[g/hr-hr]	3.0	EPA Tier 3 Standard

$$NOx\left[\frac{lb}{hr}\right] = Rating[hp] * NOx\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

NOx Emission Rate	[lb/hr]	2.0

$$NOx\left[\frac{ton}{yr}\right] = NOx\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

NOx Emissions	[ton/yr]	0.03

CO

CO Emission Factor	[g/hr-hr]	2.6	EPA Tier 3 Standard

$$CO\left[\frac{lb}{hr}\right] = Rating[hp] * CO\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

CO Emission Rate	[lb/hr]	1.7

$$CO\left[\frac{ton}{yr}\right] = CO\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

CO Emissions	[ton/yr]	0.03

VOC

VOC Emission Factor [g/hp-hr] 0.14 EPA Tier 3 Standard (HC Emission Factor)

$$VOC\left[\frac{lb}{hr}\right] = Rating[hp] * VOC\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

VOC Emission Rate	[lb/hr]	0.1

$$VOC\left[\frac{ton}{yr}\right] = VOC\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

VOC Emissions	[ton/yr]	0.00

SO2

SO2 Emission Factor [lb/hp-hr] 0.000003 EPA AP-42, Table 3.4-1

$$SO2\left[\frac{lb}{hr}\right] = Rating[hp] * SO2\ EF\left[\frac{lb}{hp * hr}\right]$$

SO2 Emission Rate	[lb/hr]	0.00

$$SO2\left[\frac{ton}{yr}\right] = SO2\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

SO2 Emissions	[ton/yr]	0.00

PM-10

PM-10 Emission Factor [g/hp-hr] 0.15 EPA Tier 3 Standard

$$PM10\left[\frac{lb}{hr}\right] = Rating[hp] * PM10\ EF\left[\frac{g}{hp * hr}\right] * \frac{[lb]}{453.6[g]}$$

PM-10 Emission Rate	[lb/hr]	0.1

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

PM-10 Emissions	[ton/yr]	0.00

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Cooling Tower

Criteria Pollutants

Inputs (Constants)	Units	Value	Source
Annual Operation	[hr]	8,760	PTC Application
Flow Rate	[gpm]	63,200	Equipment Design Parameter
TDS Concentration	[ppm]	5,000	PTC Application
TDS Flow	[lb/hr]	158,126	Calculation
Flow Producing PM-10	[%]	84%	"Calculating Realistic PM-10 Emissions from Cooling Towers"
Drift Eliminator Efficiency	[%]	0.0005%	Vendor Guarantee

PM-10 (Cooling Tower)

$$PM10\left[\frac{lb}{hr}\right] = TDS\ Flow\left[\frac{lb}{hr}\right] * Control\ Eff[\%] * PM10\ Factor[\%]$$

PM-10 Emission Rate	[lb/hr]	0.66

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops[hr] * \frac{[ton]}{2000[lb]}$$

PM-10 Emissions	[ton/yr]	2.91

Dry Chemical Storage Silos

Inputs (Constants)	Units	Value	Source
Annual Operation	[hr/silo]	48	PTC Application
Daily Operation	[hr/silo]	2	PTC Application
Blower Flowrate	[cfm]	1,500	Equipment Design Parameter
Loading Emissions	[gr/scf]	0.01	Vendor Guarantee
Number of Silos		3	Contractor Design

PM-10 (Storage Silos)

$$PM10\left[\frac{lb}{hr}\right] = Blower\ Flow[cfm] * Loading\ Emissions[gr/scf] * \left[\frac{60min}{hr}\right] * \left[\frac{lb}{7000gr}\right]$$

PM-10 Emission Rate	[lb/hr]	0.13

$$PM10\left[\frac{ton}{yr}\right] = PM10\left[\frac{lb}{hr}\right] * Annual\ Ops\left[\frac{hr}{silo}\right] * 6[silos] * \frac{[ton]}{2000[lb]}$$

PM-10 Emissions	[ton/yr]	0.01

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Hazardous Air Pollutants

Pollutant	Facility Wide Ton/yr
1,3-Butadiene	3.62E-03
Acetaldehyde	3.37E-01
Acrolein	5.38E-02
Arsenic	1.91E-04
Benzene	1.03E-01
Beryllium	1.15E-05
Cadmium	1.05E-03
Chromium	1.34E-03
Cobalt	8.03E-05
Dichlorobenzene	1.15E-03
Ethyl Benzene	2.69E-01
Formaldehyde	6.04E+00
Hexane	1.72E+00
Manganese	3.63E-04
Mercury	2.48E-04
Naphthalene	1.15E-02
Nickel	2.01E-03
Propylene Oxide	2.44E-01
POM	1.61E-05
Selenium	2.29E-05
Toluene	1.10E+00
Xylenes	5.38E-01
Total	**10.4**

Combustion Turbine

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	2,134	Vendor Information
HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.1-3

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{MMBtu}\right] * Heat\ Input\left[\frac{MMBtu}{hr}\right] * AnnualOps\left[\frac{hr}{yr}\right] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
1,3-Butadiene	4.30E-07	3.62E-03
Acetaldehye	4.00E-05	3.36E-01
Acrolein	6.40E-06	5.38E-02
Benzene	1.20E-05	1.01E-01
Ethylbenzene	3.20E-05	2.69E-01
Formaldehyde	7.10E-04	5.97E+00
Naphthalene	1.30E-06	1.09E-02
Propylene Oxide	2.90E-05	2.44E-01
Toluene	1.30E-04	1.09E+00
Xylenes	6.40E-05	5.38E-01

Duct Burners

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Heat Input	[MMBtu/hr]	241	Vendor Information
Fuel Heating Value	[Btu/scf]	994	40 CFR 98, Table C-1
Organic HAP Emission Factors	[lb/10^6 scf]	See Below	EPA AP-42; Table 1.4-3
Metal HAP Emission Factors	[lb/10^6 scf]	See Below	EPA AP-42; Table 1.4-4

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{10^6 scf}\right] * HI\left[\frac{MMBtu}{hr}\right] * \left[\frac{10^6 scf}{994\ MMBtu}\right] * AnnualOps\left[\frac{hr}{yr}\right] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
Arsenic	2.00E-04	1.91E-04
Benzene	2.10E-03	2.01E-03
Beryllium	1.20E-05	1.15E-05
Cadmium	1.10E-03	1.05E-03
Chromium	1.40E-03	1.34E-03
Cobalt	8.40E-05	8.03E-05
Dichlorobenzene	1.20E-03	1.15E-03
Formaldehyde	7.50E-02	7.17E-02
Hexane	1.80E+00	1.72E+00
Manganese	3.80E-04	3.63E-04
Mercury	2.60E-04	2.48E-04
Naphthalene	6.10E-04	5.83E-04
Nickel	2.10E-03	2.01E-03
POM*	1.14E-05	1.09E-05
Selenium	2.40E-05	2.29E-05
Toluene	3.40E-03	3.25E-03
Xylenes		

* POM Emission Factor is the sum of 7-PAH Group emission factors

Emergency Generator

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	60	PTC Application
Fuel Use	[gal/hr]	53.6	Vendor Information
Fuel Heating Value	[MMBtu/gal]	0.137	AP-42; Chapter 3
Organic HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-3
PAH HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-4

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{MMBtu}\right] * Fuel\left[\frac{gal}{hr}\right] * \left[.137\frac{MMBtu}{gal}\right] * AnnualOps\left[\frac{hr}{yr}\right] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
Acetaldehye	2.52E-05	5.55E-06
Acrolein	7.88E-06	1.74E-06
Benzene	7.76E-04	1.71E-04
Formaldehyde	7.89E-05	1.74E-05
POM	4.50E-06	9.92E-07
Toluene	2.81E-04	6.19E-05
Xylenes	1.93E-04	4.25E-05

Fire Pump

Inputs (Constants)	Units	Value	Source
Full Load Operation	[hrs]	30	PTC Application
Fuel Use	[gal/hr]	15.8	Vendor Information
Fuel Heating Value	[MMBtu/gal]	0.137	AP-42, Chapter 3
Organic HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-3
PAH HAP Emission Factors	[lb/MMBtu]	See Below	EPA AP-42; Table 3.4-4

$$HAP\left[\frac{ton}{yr}\right] = EF\left[\frac{lb}{MMBtu}\right] * Fuel\left[\frac{gal}{hr}\right] * \left[.137\frac{MMBtu}{gal}\right] * AnnualOps\left[\frac{hr}{yr}\right] * \frac{[ton]}{2000[lb]}$$

HAP Pollutant	Emission Factors	Emissions [ton/yr]
1,3-Butadiene	3.91E-05	1.27E-06
Acetaldehye	7.67E-04	2.49E-05
Acrolein	9.25E-05	3.00E-06
Benzene	9.33E-04	3.03E-05
Formaldehyde	1.18E-03	3.83E-05
Naphthalene	8.48E-05	2.75E-06
POM	1.30E-04	4.22E-06
Toluene	4.09E-04	1.33E-05
Xylenes	2.85E-04	9.26E-06

Langley Gulch Power Plant
Tier 1 Operating Permit
Emission Calculation Worksheet

Toxic Air Pollutants

Pollutant	Category	Averaging Period	Screening Level [lb/hr]	Annual Average	24-Hour Average
1,3-Butadiene	HAP / TAP-586	Annual	2.40E-05	8.26E-04	9.21E-04
2-Methylnaphthalene	HAP / TAP-586	Annual	9.10E-05	5.24E-06	5.82E-06
3-Methylcholanthrene	HAP / TAP-586	Annual	2.50E-06	3.93E-07	4.36E-07
7,12-Dimethylbenz(a)anthracene	HAP / TAP-586	Annual	9.10E-05	3.49E-06	3.88E-06
Acenaphthene	HAP / TAP-586	Annual	9.10E-05	6.38E-07	6.29E-06
Acenaphthylene	HAP / TAP-586	Annual	9.10E-05	8.93E-07	1.22E-05
Acetaldehyde	HAP / TAP-586	Annual	3.00E-03	7.68E-02	8.55E-02
Acrolein	HAP / TAP-585	24-hour	1.70E-02	1.23E-02	1.37E-02
Ammonia	TAP-585	24-hour	1.20E+00	1.67E+01	1.86E+01
Anthracene	HAP / TAP-586	Annual	9.10E-05	5.99E-07	2.25E-06
Arsenic	HAP / TAP-586	Annual	1.50E-06	4.36E-05	4.85E-05
Barium	TAP-585	24-hour	3.30E-02	9.60E-04	1.07E-03
Benz(a)anthracene	TAP-586			4.36E-07	1.34E-06
Benzene	HAP / TAP-586	Annual	8.00E-04	2.36E-02	2.71E-02
Benzo(a)pyrene	HAP / TAP-586	Annual	2.00E-06	2.76E-07	6.22E-07
Benzo(b)fluoranthene				4.49E-07	1.80E-06
Benzo(g,h,l)perylene	HAP / TAP-586	Annual	9.10E-05	2.93E-07	1.01E-06
Benzo(k)fluoranthene				4.05E-07	7.17E-07
Beryllium	HAP / TAP-586	Annual	2.80E-05	2.62E-06	2.91E-06
Cadmium	HAP / TAP-586	Annual	3.70E-06	2.40E-04	2.67E-04
Chromium	HAP / TAP-585	24-hour	3.30E-02	3.05E-04	3.39E-04
Chrysene				4.72E-07	2.34E-06
Cobalt	HAP / TAP-585	24-hour	3.30E-03	1.83E-05	2.04E-05
Copper	TAP-585	24-hour	1.30E-02	1.85E-04	2.06E-04
Dibenzo(a,h)anthracene				2.83E-07	7.64E-07
Dichlorobenzene (o-and 1,4-)	HAP / TAP-585	24-hour	2.00E+01	2.62E-04	2.91E-04
Ethyl benzene	HAP / TAP-585	24-hour	2.90E+01	6.15E-02	6.83E-02
Fluoranthene	HAP / TAP-586	Annual	9.10E-05	7.08E-07	1.38E-06
Fluorene	HAP / TAP-586	Annual	9.10E-05	1.46E-06	1.88E-05
Formaldehyde	HAP / TAP-586	Annual	5.10E-04	1.38E+00	1.53E+00
Hexane	HAP / TAP-585	24-hour	1.20E+01	3.93E-01	4.36E-01
Indenol(1,2,3,-cd)pyrene				4.16E-07	9.75E-07
Manganese	HAP / TAP-585	24-hour	6.70E-02	8.29E-05	9.21E-05
Mercury	HAP / TAP-585	24-hour	1.00E-03	5.67E-05	6.30E-05
Molybdenum	TAP-585	24-hour	3.33E-01	2.40E-04	2.67E-04
Naphthalene	TAP-585	24-hour	3.33E+00	2.64E-03	3.09E-03
Naphthalene (as PAH)	HAP / TAP-586	Annual	9.10E-05	0.00E+00	0.00E+00
Nickel	HAP / TAP-586	Annual	2.75E-05	4.58E-04	5.09E-04
Nitrous oxide	TAP-585	24-hour	6.00E+00	6.24E+00	6.94E+00
Pentane	TAP-585	24-hour	1.18E+02	5.67E-01	6.30E-01
Phenanthrene	HAP / TAP-586	Annual	9.10E-05	5.97E-06	5.66E-05
Propylene oxide	HAP / TAP-585	24-hour	3.20E+00	5.59E-02	6.55E-02
POM (7-PAH Group)	HAP / TAP-586	Annual	2.00E-06	2.56E-06	7.51E-06
Pyrene	HAP / TAP-586	Annual	9.10E-05	1.31E-06	6.16E-06
Selenium	HAP / TAP-585	24-hour	1.30E-02	5.24E-06	5.82E-06
Sulfuric acid mist	TAP-585	24-hour	6.70E-02	2.35E-01	2.61E-01
Toluene	HAP / TAP-585	24-hour	2.50E+01	2.50E-01	2.79E-01
Total PAH			2.60E+01	7.34E-03	7.64E-03
Vanadium	TAP-585	24-hour	2.70E+01	5.14E-04	8.32E-04
Xylenes	HAP / TAP-585	24-hour	2.80E+01	1.23E-01	1.37E-01
Zinc	TAP-585	24-hour	2.90E+01	6.33E-03	7.03E-03

Emission Source	Units	Value	Source
Combustion Turbine & Duct Burners			
Full Load Operation	[hrs]	6,902	PTC Application
Startup & Shutdown	[hrs]	982	PTC Application
Turbine Heat Input	[MMBtu/hr]	2,134	Vendor Information
Duct Burner Heat Input	[MMBtu/hr]	241	Vendor Information

TAP-585/586 Equation

$$TAP\left[\frac{lb}{hr}\right] = CT\ EF\left[\frac{lb}{MMBtu}\right] * CT\ Fuel\ Use\left[\frac{MMBtu}{hr}\right] + \frac{DB\ EF\left[\frac{lb}{10^6 scf}\right] * DB\ Fuel\ Use\left[\frac{MMBtu}{hr}\right]}{Heating\ Value\left[994\ \frac{Btu}{scf}\right]}$$

Ammonia Equation

$$NH_3\left[\frac{lb}{hr}\right] = \frac{NH_3[ppm] * NH_3[MW] * FFactor\left[\frac{dscf}{MMBtu}\right] * Fuel\ Flow\left[\frac{MMBtu}{hr}\right]}{10^6 * 385.6} * \left(\frac{20.9}{20.9 - 15}\right)$$

Sulfuric Acid Equation

$$H_2SO_4\left[\frac{lb}{hr}\right] = \frac{\left(0.5\left[\frac{gr}{100scf}\right] * 5\%\right) * HI\left[\frac{MMBtu}{hr}\right] * \left[\frac{100scf}{.0994\ MMBtu}\right] * \frac{H_2SO_4[MW]}{S[MW]}}{7000\left[\frac{gr}{lb}\right]}$$

Pollutant	Category	Averaging Period	Combustion Turbine Emission Factor	Duct Burner Emission Factor	Maximum Rate [lb/hr]	Annual Average [lb/hr]	24-Hour Average [lb/hr]	Annual Emissions [tpy]
1,3-Butadiene	HAP / TAP-586	Annual	4.30E-07		9.18E-04	**8.26E-04**	9.18E-04	3.62E-03
2-Methylnaphthalene	HAP / TAP-586	Annual		2.40E-05	5.82E-06	**5.24E-06**	5.82E-06	2.29E-05
3-Methylcholanthrene	HAP / TAP-586	Annual		1.80E-06	4.36E-07	**3.93E-07**	4.36E-07	1.72E-06
7,12-Dimethylbenz(a)anthracene	HAP / TAP-586	Annual		1.60E-05	3.88E-06	**3.49E-06**	3.88E-06	1.53E-05
Acenaphthene	HAP / TAP-586	Annual		1.80E-06	4.36E-07	**3.93E-07**	4.36E-07	1.72E-06
Acenaphthylene	HAP / TAP-586	Annual		1.80E-06	4.36E-07	**3.93E-07**	4.36E-07	1.72E-06
Acetaldehyde	HAP / TAP-586	Annual	4.00E-05	2.52E-05	8.54E-02	**7.68E-02**	8.54E-02	3.37E-01
Acrolein	HAP / TAP-585	24-hour	6.40E-06	7.88E-06	1.37E-02	1.23E-02	**1.37E-02**	5.38E-02
Ammonia	TAP-585	24-hour	5.0 [ppm]		1.86E+01	1.67E+01	**1.86E+01**	7.32E+01
Anthracene	HAP / TAP-586	Annual		2.40E-06	5.82E-07	**5.24E-07**	5.82E-07	2.29E-06
Arsenic	HAP / TAP-586	Annual		2.00E-04	4.85E-05	**4.36E-05**	4.85E-05	1.91E-04
Barium	TAP-585	24-hour		4.40E-03	1.07E-03	9.60E-04	**1.07E-03**	4.21E-03
Benz(a)anthracene	TAP-586			1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Benzene	HAP / TAP-586	Annual	1.20E-05	2.10E-03	2.61E-02	**2.35E-02**	2.61E-02	1.03E-01
Benzo(a)pyrene	HAP / TAP-586	Annual		1.20E-06	2.91E-07	**2.62E-07**	2.91E-07	1.15E-06
Benzo(b)fluoranthene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Benzo(g,h,I)perylene	HAP / TAP-586	Annual		1.20E-06	2.91E-07	**2.62E-07**	2.91E-07	1.15E-06
Benzo(k)fluoranthene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Beryllium	HAP / TAP-586	Annual		1.20E-05	2.91E-06	**2.62E-06**	2.91E-06	1.15E-05
Cadmium	HAP / TAP-586	Annual		1.10E-03	2.67E-04	**2.40E-04**	2.67E-04	1.05E-03
Chromium	HAP / TAP-585	24-hour		1.40E-03	3.39E-04	3.05E-04	**3.39E-04**	1.34E-03
Chrysene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Cobalt	HAP / TAP-585	24-hour		8.40E-05	2.04E-05	1.83E-05	**2.04E-05**	8.03E-05
Copper	TAP-585	24-hour		8.50E-04	2.06E-04	1.85E-04	**2.06E-04**	8.12E-04
Dibenzo(a,h)anthracene				1.20E-06	2.91E-07	2.62E-07	2.91E-07	1.15E-06
Dichlorobenzene (o-and 1,4-)	HAP / TAP-585	24-hour		1.20E-03	2.91E-04	2.62E-04	**2.91E-04**	1.15E-03
Ethyl benzene	HAP / TAP-585	24-hour	3.20E-05		6.83E-02	6.15E-02	**6.83E-02**	2.69E-01
Fluoranthene	HAP / TAP-586	Annual		3.00E-06	7.27E-07	**6.55E-07**	7.27E-07	2.87E-06
Fluorene	HAP / TAP-586	Annual		2.80E-06	6.79E-07	**6.11E-07**	6.79E-07	2.68E-06
Formaldehyde	HAP / TAP-586	Annual	7.10E-04	7.50E-02	1.53E+00	**1.38E+00**	1.53E+00	6.04E+00
Hexane	HAP / TAP-585	24-hour		1.80E+00	4.36E-01	3.93E-01	**4.36E-01**	1.72E+00
Indenol(1,2,3,-cd)pyrene				1.80E-06	4.36E-07	3.93E-07	4.36E-07	1.72E-06
Manganese	HAP / TAP-585	24-hour		3.80E-04	9.21E-05	8.29E-05	**9.21E-05**	3.63E-04
Mercury	HAP / TAP-585	24-hour		2.60E-04	6.30E-05	5.67E-05	**6.30E-05**	2.48E-04
Molybdenum	TAP-585	24-hour		1.10E-03	2.67E-04	2.40E-04	**2.67E-04**	1.05E-03
Naphthalene	TAP-585	24-hour	1.30E-06	6.10E-04	2.92E-03	2.63E-03	**2.92E-03**	1.15E-02
Nickel	HAP / TAP-586	Annual		2.10E-03	5.09E-04	**4.58E-04**	5.09E-04	2.01E-03
Nitrous oxide	TAP-585	24-hour	3.00E-03	2.20E+00	6.94E+00	6.24E+00	**6.94E+00**	2.73E+01
Pentane	TAP-585	24-hour		2.60E+00	6.30E-01	5.67E-01	**6.30E-01**	2.48E+00
Phenanthrene	HAP / TAP-586	Annual		1.70E-05	4.12E-06	**3.71E-06**	4.12E-06	1.62E-05
Propylene oxide	HAP / TAP-585	24-hour	2.90E-05		6.19E-02	5.57E-02	**6.19E-02**	2.44E-01
POM (7-PAH Group)	HAP / TAP-586	Annual			2.62E-06	**2.36E-06**	2.62E-06	1.03E-05
Pyrene	HAP / TAP-586	Annual		5.00E-06	1.21E-06	**1.09E-06**	1.21E-06	4.78E-06
Selenium	HAP / TAP-585	24-hour		2.40E-05	5.82E-06	5.24E-06	**5.82E-06**	2.29E-05
Sulfuric acid mist	TAP-585	24-hour	5% of Fuel S Content		2.61E-01	2.35E-01	**2.61E-01**	1.03E+00
Toluene	HAP / TAP-585	24-hour	1.30E-04	3.40E-03	2.78E-01	2.50E-01	**2.78E-01**	1.10E+00
Total PAH			2.20E-06		7.64E-03	**7.34E-03**	7.64E-03	1.63E-02
Vanadium	TAP-585	24-hour		2.30E-03	5.58E-04	5.02E-04	**5.58E-04**	2.20E-03
Xylenes	HAP / TAP-585	24-hour	6.40E-05		1.37E-01	1.23E-01	**1.37E-01**	5.38E-01
Zinc	TAP-585	24-hour		2.90E-02	7.03E-03	6.33E-03	**7.03E-03**	2.77E-02

Emission Source	Units	Value	Source
Emergency Diesel Generator			
Annual Operation	[hrs]	60	PTC Application
Daily Operations	[hrs]	4	PTC Application
Fuel Usage	[gph]	53.6	Vendor Information
Engine Rating	[bhp]	1214	Vendor Information
Fuel Heating Value	[btu/gal]	137030	AP-42; Chapter 3

TAP-585/586 Equation

$$TAP\left[\frac{lb}{hr}\right] = \frac{EF\left[\frac{lb}{MMBtu}\right] * Fuel\ Use\left[\frac{gal}{hr}\right] * Heating\ Value\left[\frac{Btu}{gal}\right]}{1e6\left[\frac{Btu}{MMBtu}\right]}$$

Pollutant	Category	Averaging Period	EDG Emission Factor	Maximum Rate [lb/hr]	Annual Average [lb/hr]	24-Hour Average [lb/hr]	Annual Emissions [tpy]
Acenaphthene	HAP / TAP-586	Annual	4.68E-06	3.44E-05	**2.35E-07**	5.73E-06	1.03E-06
Acenaphthylene	HAP / TAP-586	Annual	9.23E-06	6.78E-05	**4.64E-07**	1.13E-05	2.03E-06
Acetaldehyde	HAP / TAP-586	Annual	2.52E-05	1.85E-04	**1.27E-06**	3.08E-05	5.55E-06
Acrolein	HAP / TAP-585	24-hour	7.88E-06	5.79E-05	3.96E-07	**9.65E-06**	1.74E-06
Anthracene	HAP / TAP-586	Annual	1.23E-06	9.03E-06	**6.19E-08**	1.51E-06	2.71E-07
Benz(a)anthracene	TAP-586		6.22E-07	4.57E-06	3.13E-08	7.61E-07	1.37E-07
Benzene	HAP / TAP-586	Annual	7.76E-04	5.70E-03	**3.90E-05**	9.50E-04	1.71E-04
Benzo(a)pyrene	HAP / TAP-586	Annual	2.57E-07	1.89E-06	**1.29E-08**	3.15E-07	5.66E-08
Benzo(b)fluoranthene			1.11E-06	8.15E-06	5.58E-08	1.36E-06	2.45E-07
Benzo(g,h,I)perylene	HAP / TAP-586	Annual	5.56E-07	4.08E-06	**2.80E-08**	6.81E-07	1.23E-07
Benzo(k)fluoranthene			2.18E-07	1.60E-06	1.10E-08	2.67E-07	4.80E-08
Chrysene			1.53E-06	1.12E-05	7.70E-08	1.87E-06	3.37E-07
Dibenzo(a,h)anthracene			3.46E-07	2.54E-06	1.74E-08	4.24E-07	7.62E-08
Fluorene	HAP / TAP-586	Annual	1.28E-05	9.40E-05	**6.44E-07**	1.57E-05	2.82E-06
Formaldehyde	HAP / TAP-586	Annual	7.89E-05	5.80E-04	**3.97E-06**	9.66E-05	1.74E-05
Indenol(1,2,3,-cd)pyrene			4.14E-07	3.04E-06	2.08E-08	5.07E-07	9.12E-08
Naphthalene	TAP-585	24-hour	1.30E-04	9.55E-04	6.54E-06	**1.59E-04**	2.86E-05
Phenanthrene	HAP / TAP-586	Annual	4.08E-05	3.00E-04	**2.05E-06**	4.99E-05	8.99E-06
Propylene oxide	HAP / TAP-585	24-hour	2.79E-03	2.05E-02	1.40E-04	**3.42E-03**	6.15E-04
POM (7-PAH Group)	HAP / TAP-586	Annual		2.85E-05	**1.95E-07**	4.74E-06	8.54E-07
Pyrene	HAP / TAP-586	Annual	3.71E-06	2.72E-05	**1.87E-07**	4.54E-06	8.17E-07
Toluene	HAP / TAP-585	24-hour	2.81E-04	2.06E-03	1.41E-05	**3.44E-04**	6.19E-05
Total PAH			2.12E-04	1.56E-03	**1.07E-05**	2.60E-04	4.67E-05
Xylenes	HAP / TAP-585	24-hour	1.93E-04	1.42E-03	9.71E-06	**2.36E-04**	4.25E-05

Emission Source	Units	Value	Source
Fire Pump Engine			
Annual Operation	[hrs]	30	PTC Application
Daily Operations	[hrs]	1	PTC Application
Fuel Usage	[gph]	15	Vendor Information
Engine Rating	[bhp]	305	Vendor Information
Fuel Heating Value	[btu/gal]	137030	AP-42; Chapter 3

TAP-585/586 Equation

$$TAP\left[\frac{lb}{hr}\right] = \frac{EF\left[\frac{lb}{MMBtu}\right] * Fuel\ Use\left[\frac{gal}{hr}\right] * Heating\ Value\left[\frac{Btu}{gal}\right]}{1e6\left[\frac{Btu}{MMBtu}\right]}$$

Pollutant	Category	Averaging Period	FP Emission Factor	Maximum Rate [lb/hr]	Annual Average [lb/hr]	24-Hour Average [lb/hr]	Annual Emissions [tpy]
1,3-Butadiene	HAP / TAP-586	Annual	3.91E-05	8.04E-05	**2.75E-07**	3.35E-06	1.21E-06
Acenaphthene	HAP / TAP-586	Annual	1.42E-06	2.92E-06	**1.00E-08**	1.22E-07	4.38E-08
Acenaphthylene	HAP / TAP-586	Annual	5.06E-06	1.04E-05	**3.56E-08**	4.33E-07	1.56E-07
Acetaldehyde	HAP / TAP-586	Annual	7.67E-04	1.58E-03	**5.40E-06**	6.57E-05	2.36E-05
Acrolein	HAP / TAP-585	24-hour	9.25E-05	1.90E-04	6.51E-07	**7.92E-06**	2.85E-06
Anthracene	HAP / TAP-586	Annual	1.87E-06	3.84E-06	**1.32E-08**	1.60E-07	5.77E-08
Benz(a)anthracene	TAP-586		1.68E-06	3.45E-06	1.18E-08	1.44E-07	5.18E-08
Benzene	HAP / TAP-586	Annual	9.33E-04	1.92E-03	**6.57E-06**	7.99E-05	2.88E-05
Benzo(a)pyrene	HAP / TAP-586	Annual	1.88E-07	3.86E-07	**1.32E-09**	1.61E-08	5.80E-09
Benzo(b)fluoranthene			9.91E-08	2.04E-07	6.98E-10	8.49E-09	3.06E-09
Benzo(g,h,I)perylene	HAP / TAP-586	Annual	4.89E-07	1.01E-06	**3.44E-09**	4.19E-08	1.51E-08
Benzo(k)fluoranthene			1.55E-07	3.19E-07	1.09E-09	1.33E-08	4.78E-09
Chrysene			3.53E-07	7.26E-07	2.48E-09	3.02E-08	1.09E-08
Dibenzo(a,h)anthracene			5.83E-07	1.20E-06	4.10E-09	4.99E-08	1.80E-08
Fluoranthene	HAP / TAP-586	Annual	7.61E-06	1.56E-05	**5.36E-08**	6.52E-07	2.35E-07
Fluorene	HAP / TAP-586	Annual	2.92E-05	6.00E-05	**2.06E-07**	2.50E-06	9.00E-07
Formaldehyde	HAP / TAP-586	Annual	1.18E-03	2.43E-03	**8.31E-06**	1.01E-04	3.64E-05
Indenol(1,2,3,-cd)pyrene			3.75E-07	7.71E-07	2.64E-09	3.21E-08	1.16E-08
Naphthalene	TAP-585	24-hour	8.48E-05	1.74E-04	5.97E-07	**7.26E-06**	2.61E-06
Phenanthrene	HAP / TAP-586	Annual	2.94E-05	6.04E-05	**2.07E-07**	2.52E-06	9.06E-07
Propylene oxide	HAP / TAP-585	24-hour	2.58E-03	5.30E-03	1.82E-05	**2.21E-04**	7.95E-05
POM (7-PAH Group)	HAP / TAP-586	Annual		3.60E-06	**1.23E-08**	1.50E-07	5.41E-08
Pyrene	HAP / TAP-586	Annual	4.78E-06	9.83E-06	**3.36E-08**	4.09E-07	1.47E-07
Toluene	HAP / TAP-585	24-hour	4.09E-04	8.41E-04	2.88E-06	**3.50E-05**	1.26E-05
Total PAH			1.68E-04	3.45E-04	**1.18E-06**	1.44E-05	5.18E-06
Xylenes	HAP / TAP-585	24-hour	2.85E-04	5.86E-04	2.01E-06	**2.44E-05**	8.79E-06

Appendix C

Acid Rain Program Permit Application

IDAHO POWER®
An IDACORP Company

January 11, 2010

Morrie Lewis
Permit Writer
Idaho Department of Environmental Quality
Air Quality Division
1410 N. Hilton
Boise, ID 83706

Subject: Idaho Power Company – Langley Gulch Power Plant
Acid Rain Permit Application

Dear Mr. Lewis:

I am submitting this Acid Rain permit application in accordance with the requirements of 40 CFR 72.30 and 31. As stated in the above rule, the deadline for submittal of the application is at least 24 months before the date on which the unit commences operation. Langley Gulch is anticipated to commence commercial operation (CCO) on June 1, 2012. The monitor certification deadline will be the earlier of 90 unit operating days or 180 calendar days after the CCO date in accordance with 40 CFR 75.4(b)(2).

Langley Gulch will be subject to the permitting requirements of 40 CFR 72 through 40 CFR 75. The combustion turbine will be equipped with a continuous emissions monitoring system (CEMS) to monitor nitrogen oxide (NO_x) emissions from the exhaust stack to ensure compliance with 40 CFR 75. In addition, to ensure compliance with 40 CFR 72.9(c), the facility will hold sulfur dioxide (SO_2) allowances in excess of the total annual emissions of SO_2 for the previous calendar year. SO_2 allowances shall be tracked using the EPA's Clean Air Markets Division (CAMD) Business System. Langley Gulch is not subject to the requirements of 40 CFR 76 since it does not meet the applicability requirements of §76.1 as a "coal-fired utility unit".

If you have any questions regarding the Acid Rain Permit Application for the Langley Gulch Power Plant, please feel free to contact me at (208) 388-2426.

Sincerely,

Trevor Mahlum
Engineer – Power Production

Encl: Acid Rain Permit Application

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ~ new ~ revised ~ for Acid Rain permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

Facility (Source) Name	State	Plant Code
Langley Gulch Power Plant	Idaho	57028

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
CT1	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit;

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:

(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

Sulfur Dioxide Requirements, Cont'd.

STEP 3, Cont'd.

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:
(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the

submission of a new certificate of representation changing the designated representative;

STEP 3, Cont'd.

Recordkeeping and Reporting Requirements, Cont'd.

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,
(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.
(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

Langley Gulch Power Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating

Effect on Other Authorities, Cont'd.

to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements
under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Dale Koger	
Signature Dale Koger	Date 1/11/10

Appendix D

GHG Emission Calculations

The Langley Gulch facility has four (4) fuel burning emission sources onsite. The combustion turbine and duct burners, which emit through the HRSG stack, the diesel fired emergency generator, and the emergency diesel fire pump engine. The combustion turbine and duct burners are subject to the greenhouse gas (GHG) reporting requirements under 40 CFR 98 as a Source Category listed under Table A-3; Electricity generation unit that report CO_2 mass emissions year round through 40 CFR part 75. The emergency generator and the emergency diesel fire pump engine are exempt from the reporting requirements of 40 CFR 98 in accordance with 40 CFR 98.30(a)(2).

Combustion Turbine GHG Emission Calculations

$$\mathbf{CO2[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 2,134 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 53.02 kg/MMBtu [40 CFR 98; Subpart C, Table C-1]*
- *Global Warming Potential = 1 [40 CFR 98; Subpart A, Table A-1]*

*CO_2 [lb/hr] = 2,134 [MMBtu/hr] * 53.02 [kg/MMbtu[* 2.2 [lb/kg] = 248,918.3 [lb/hr]*

*CO_2 [ton/yr] = (248,918.3 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 981,235.9 [ton/yr]*

*CO_2 [metric ton/yr] = 981,235.9 [ton/yr] * 0.91 [metric ton/ton] = **922,361.8 [metric ton/yr]***

$$\mathbf{CH4[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 2,134 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-3 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 21 [40 CFR 98; Subpart A, Table A-1*

*CH_4 [lb/hr] = 2,134 [MMBtu/hr] * 1.0e-3 [kg/MMbtu[* 2.2 [lb/kg] = 4.695 [lb/hr]*

*CH_4 [ton/yr] = (4.695 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 18.51 [ton/yr]*

*CH_4 [metric ton/yr] = 18.51 [ton/yr] * 0.91 [metric ton/ton] = **16.84 [metric ton/yr]***

$$\mathbf{N2O[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]}$$

- *Fuel Flow = 2,134 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-4 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 310 [40 CFR 98; Subpart A, Table A-1]*

*N_2O [lb/hr] = 2,134 [MMBtu/hr] * 1.0e-4 [kg/MMbtu[* 2.2 [lb/kg] = 0.4695 [lb/hr]*

*N_2O [ton/yr] = (.4695 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 1.851 [ton/yr]*

*N_2O [metric ton/yr] = 1.851 [ton/yr] * 0.91 [metric ton/ton] = **1.684 [metric ton/yr]***

$$CO2e[ton/yr] = CO2[metric\ ton/yr] + CH4[metric\ ton/yr] * 21[GWP] + N2O[metric\ ton/yr] * 310[GWP]$$

*CO_2e [metric ton/yr] = 922,361.8[metric ton CO_2/yr] + (16.84 [metric ton CH_4/yr] * 21 [CH_4 GWP]) + (1.684 [metric ton N_2O] * 310 [N_2O GWP])*

CO_2e = 923,237.5 [metric ton/yr]

<u>Duct Burner GHG Emission Calculations</u>

$$CO2[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]$$

- *Fuel Flow = 241MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 53.02 kg/MMBtu [40 CFR 98; Subpart C, Table C-1]*
- *Global Warming Potential = 1 [40 CFR 98; Subpart A, Table A-1]*

*CO_2 [lb/hr] = 241 [MMBtu/hr] * 53.02 [kg/MMbtu[* 2.2 [lb/kg] = 28,111.2 [lb/hr]*

*CO_2 [ton/yr] = (28,111.2 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 110,814.4 [ton/yr]*

*CO_2 [metric ton/yr] = 110,814.4 [ton/yr] * 0.91 [metric ton/ton] = **100,841.1 [metric ton/yr]***

$$CH4[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]$$

- *Fuel Flow = 241 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-3 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 21 [40 CFR 98; Subpart A, Table A-1*

*CH_4 [lb/hr] = 241 [MMBtu/hr] * 1.0e-3 [kg/MMbtu[* 2.2 [lb/kg] = 0.53 [lb/hr]*

*CH_4 [ton/yr] = (0.53 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 2.09 [ton/yr]*

*CH_4 [metric ton/yr] = 2.09 [ton/yr] * 0.91 [metric ton/ton] = **1.90 [metric ton/yr]***

$$N2O[lb/hr] = Fuel\ Flow[MMBtu/hr] * Emission\ Factor[kg/MMBtu] * 2.2[lb/kg]$$

- *Fuel Flow = 241 MMBtu/hr [Max fuel flow through combustion turbine]*
- *Emission Factor = 1.0e-4 kg/MMBtu [40 CFR 98; Subpart C, Table C-2]*
- *Global Warming Potential = 310 [40 CFR 98; Subpart A, Table A-1]*

*N_2O [lb/hr] = 241 [MMBtu/hr] * 1.0e-4 [kg/MMbtu[* 2.2 [lb/kg] = 0.05 [lb/hr]*

*N_2O [ton/yr] = (0.05 [lb/hr] * 7,884 [hr/yr]) / 2,000 [lb/ton] = 0.21 [ton/yr]*

*N_2O [metric ton/yr] = 0.21 [ton/yr] * 0.91 [metric ton/ton] = **0.19 [metric ton/yr]***

$$CO2e[ton/yr] = CO2[metric\ ton/yr] + CH4[metric\ ton/yr] * 21[GWP] + N2O[metric\ ton/yr] * 310[GWP]$$

*CO_2e [metric ton/yr] = 100,841 [metric ton CO_2/yr] + 1.90 [metric ton CH_4/yr] * 21 [CH_4 GWP] + 0.19 [metric ton N_2O] * 310 [N_2O GWP]*

CO_2e = 100,940 [metric ton/yr]

<u>Facility GHG Emissions Subject to 40 CFR 98</u>

$$CO2e[metric\ ton/yr] = CO2e[Turbine] + CO2e[Duct\ Burners]$$

CO_2e = 923,237.5 [metric tons/yr] + 100,940 [metric tons/yr]

CO_2e = 1,024,177.5 [metric tons/yr]