Statement of Basis

Tier I Operating Permit No. T1-2013.0017
Project ID 61165

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

Facility ID 075-00012

Final

November 8, 2013
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Permit Writer

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

1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BHP	brake horsepower
Btu	British thermal units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CatOx	catalytic oxidation
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
CT	combustion turbine
CT1	combustion turbine and duct burner
DAHS	data acquisition and handling system
DEQ	Idaho Department of Environmental Quality
dscf	dry standard cubic feet
EPA	United States Environmental Protection Agency
g	grams
gal	gallons
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
HP	horsepower
hr	hours
hr/yr	hours per consecutive 12-calendar-month period
HRSG	heat recovery steam generating unit
ICE	internal combustion engines
ID No.	identification number
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
J	Joules
kW	kilowatts
L	liters
lb	pounds
LME	low mass emissions
MACT	Maximum Achievable Control Technology
mg	milligrams
MMBtu	million British thermal units
MM lb/yr	million pounds per consecutive 12-calendar-month period
MRRR	Monitoring, Recordkeeping and Reporting Requirements
MW	megawatts of electrical output
MWh	megawatt-hours
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants

ng	nanograms
NH_3	ammonia
NMHC	non-methane hydrocarbons
No.	number
NO	nitrogen oxide
NO_x	nitrogen oxides
NO_2	nitrogen dioxide
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PAH	polycyclic aromatic hydrocarbons
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppm	parts per million by volume
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
QA	quality assurance
QC	quality control
RATA	relative accuracy test audits
RICE	reciprocating internal combustion engines
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SCR	selective catalytic reduction
SIP	State Implementation Plan
SO_2	sulfur dioxide
TAP	toxic air pollutants
TDS	total dissolved solids
T1	Tier I operating permit
T/yr	tons per consecutive 12-calendar-month period
ULSD	ultra-low-sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compounds

2. INTRODUCTION AND APPLICABILITY

The Idaho Power Company - Langley Gulch Power Plant is classified as a major facility, as defined by IDAPA 58.01.01.008.10:

- Because the facility emits or has the potential to emit carbon monoxide (CO) in an amount greater than or equal to 100 tons per year (T/yr), and
- Because the facility emits or has the potential to emit greenhouse gases (GHG) in an amount greater than or equal to 100 T/yr. Because the facility will emit or have the potential to emit 100,000 T/yr or more of carbon dioxide equivalent (CO_2e) emissions, greenhouse gases are subject to regulation with respect to the Title V program in accordance with 40 CFR 70.2 and IDAPA 58.01.01.006.97.a.

The facility is not classified as a major source of HAP emissions as defined in IDAPA 58.01.01.008.10.a, because it does not have the potential to emit hazardous air pollutants (HAP) above the major source thresholds of 10 T/yr for any single HAP and 25 T/yr for any combination of HAP. As a designated facility defined in IDAPA 58.01.01.006.30, fugitive emissions are required to be included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

As a major facility, the Idaho Power Company - Langley Gulch Power Plant is required to apply for a Tier I operating permit pursuant to IDAPA 58.01.01.301. As part of the review of the Tier I application, IDAPA 58.01.01.362 requires that DEQ prepare a technical memorandum (statement of basis) that sets forth the legal and factual basis for the Tier I operating permit terms and conditions, including reference to the applicable statutory provisions. This document provides the basis for the Tier I operating permit for the Idaho Power Company - Langley Gulch Power Plant. The format of this Statement of Basis generally follows that of the Tier I operating permit, which is organized into the following sections:

Section 1 – Acronyms, Units, and Chemical Nomenclature

This section defines the acronyms, units, and chemical nomenclature used in this permitting action.

Section 2 – Permit Scope

This section describes the scope of this permitting action.

Section 3 – Facility-Wide Conditions

This section contains the applicable requirements that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each applicable requirement typically follow the relevant permit condition.

Sections 4 through 7 – Emissions Unit-Specific Conditions

Each emissions unit-specific section of the permit contains the requirements applicable to each of the specified emissions units. Some requirements that apply to an emissions unit (e.g., opacity limits) may be in the facility-wide conditions section. As with the facility-wide conditions, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each permit condition typically follow the relevant permit condition.

Section 8 – Insignificant Activities

This section lists emissions units and activities determined to be insignificant based on size or production as allowed by IDAPA 58.01.01.317.01.b.

Section 9 – Acid Rain Conditions

This section contains Acid Rain permit requirements pursuant to 40 CFR 72 through 78 (Title IV).

Section 10 – General Provisions

The final section of the permit contains standard terms and conditions that apply to all major facilities subject to IDAPA 58.01.01.300. This section is the same for all Tier I sources. These conditions have been reviewed by EPA and contain requirements from IDAPA 58.01.01 (Rules) and from other air quality laws and regulations. Unless expressly stated, there are no MRRR for the general provisions.

3. FACILITY INFORMATION AND APPLICATION SCOPE

3.1 Facility Description

The Idaho Power Company - Langley Gulch Power Plant operates as a one-on-one, combined-cycle plant, consisting of a natural gas-fired combustion turbine and a steam turbine. The combustion turbine is equipped with a heat recovery steam generator, 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 increases steam production and steam turbine output for peak loads.

Ancillary equipment includes a diesel-fired emergency generator, a diesel-fired fire pump, a wet cooling tower, and three dry chemical storage silos. Dry chemicals for cooling water treatment may include magnesium oxide, soda ash, and lime.

3.2 Facility Permitting History

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

Table 3.1 Summary of Permitting History

Issue Date	Permit Number	Project	Description	Status
June 25, 2010	P-2009.0092	Initial PTC	Initial PSD PTC for a power plant and ancillary equipment.	S
August 14, 2013	P-2009.0092 PROJ 61199	Revised PTC	Revised PTC P-2009.0092 (6/25/10) to revise equipment nameplate information and permit limits, including hours of operation and flow rate limits.	A
November 8, 2013	T1-2013.0017 PROJ 61165	Initial Tier I	Initial Title V Operating Permit.	A

3.3 Application Scope & Chronology

This permit is the initial Tier I operating permit for this facility. This permit incorporates permit to construct, Prevention of Significant Deterioration (PSD), and Acid Rain permit requirements.

Greenhouse gases have been recognized as regulated pollutants with respect to the Title V program in this initial Tier I permitting action.

Table 3.2 Summary of Application Chronology

Date	Description
January 11, 2010	DEQ received an Acid Rain permit application (2010AAG111).
December 20, 2010	DEQ received CEMS methodology and QA/QC plans (2010AAI2393).
April 9 & 16, 2012	DEQ received notification that commercial operation of the combustion turbine and the duct burner commenced on April 13, 2012 (2012AAI771, 2012AAI776).
April 16, 2012	DEQ received notification initial startup of the combustion turbine occurred on April 11, 2012 (2012AAI772).
June 10, 2012	DEQ received a copy of the O&M manual (2012AAI1383).
March 11, 2013	DEQ received a Tier I permit application, which included revisions to equipment information and the emissions inventory (2013AAG289).
March 20, 2013	DEQ determined that the Tier I application was incomplete (2013AAG294). Additional information was requested to address equipment vendor changes.
April 3, 2013	DEQ received supplemental information, which included a preliminary applicability analysis concerning equipment vendor changes, and provided a schedule for submitting the remaining information requested in the incompleteness letter (2013AAG453).
April 9, 2013	DEQ determined that the Tier I application was complete (2013AAG295).
April 25, 2013	DEQ received supplemental information addressing CAM applicability (2013AAG636).
April 30, 2013	DEQ received supplemental information, including a complete applicability analysis addressing equipment vendor changes and a request (application) to revise PTC limits, along with copies of CEMS methodology, QA/QC plans, and the O&M manual (2013AAG702, 2013AAG700).
May 8, 2013	DEQ received a PTC application fee.
May 15, 2013	DEQ made available the draft PTC and supporting documents for peer and regional office review.
May 20, 2013	DEQ made available the draft PTC and supporting documents for applicant review (2013AAG712[v1], 2013AAG711[v1]).
May 30, 2013	DEQ received comments from the applicant regarding the draft PTC and supporting documents (2013AAG847).
June 5, 2013	DEQ determined that the PTC application was incomplete (2013AAG858). Estimates of ambient concentrations were requested to verify compliance with applicable ambient air quality standards.
June 21, 2013	DEQ received supplemental information, including an ambient air quality compliance demonstration (2013AAG1038).
June 26 – July 11, 2013	DEQ provided an opportunity to request a public comment period on the PTC application and proposed PTC permitting action.
July 10, 2013	DEQ made available the revised draft PTC and supporting documents for peer and regional office review.
July 26, 2013	DEQ made available the revised draft PTC and supporting documents for applicant review (2013AAG712[v2], 2013AAG711[v2]).
August 7 – 12, 2013	DEQ received comments from the applicant regarding the draft PTC and supporting documents (2013AAG1404).
August 14, 2013	DEQ issued the final PTC permit (2013AAG712[v3], 2013AAG711[v3]).
July 22 – 24, 2013	DEQ made available the draft Tier I and supporting documents for peer and regional office review.
July 26, 2013	DEQ made available the draft Tier I and supporting documents for applicant review (2013AAG297[v1], 2013AAG296[v1]).
July 29 – August 12, 2013	DEQ received comments from the applicant regarding the draft Tier I and supporting documents (2013AAG1303, 2013AAG1404).
August 21, 2013	DEQ provided notification of the public comment period on the proposed action to EPA, affected states, and interested parties (2013AAG1438, 2013AAG1439, 2013AAG1392).
August 21 – September 20, 2013	DEQ provided a public comment period on the draft Tier I permit, statement of basis, and application.
September 23 – November 7, 2013	DEQ provided a review and comment period to EPA on the proposed Tier I permit, statement of basis, and application (2013AAG297[v3], 2013AAG296[v3], 2013AAG289).
November 8, 2013	DEQ issued the final T1 permit (2013AAG297[v4], 2013AAG296[v4]).

4. EMISSIONS UNITS AND EMISSION INVENTORIES

4.1 Emissions Units and Control Equipment

Table 4.1 lists the emissions units and control equipment associated with the Idaho Power Company - Langley Gulch Power Plant.

Table 4.1 Emissions Units and Control Equipment

Emissions Unit		Control Equipment
Combustion turbine and duct burner (CT1)		
Combustion turbine (CT)		
Manufacturer:	Siemens	
Model:	SGT6-5000F	
Configuration:	1x1 combined cycle	
Manufacture date:	2010	
Maximum capacity:	2,134 MMBtu/hr [(a)]	Dry low NO_x combustors
Maximum energy output:	≥190 MW	Selective catalytic reduction system
Fuel:	natural gas	Catalytic oxidation system
Fuel consumption:	2,146,600 scf/hr 793.1 MM lb/yr [(b)]	Good combustion practices
Duct burner		
Manufacturer:	Hamworthy Peabody	
Manufacture date:	2010	
Maximum capacity:	241.28 MMBtu/hr [(a)]	
Fuel:	natural gas	
Fuel consumption:	242,739 scf/hr 793.1 MM lb/yr [(b)]	
Emergency generator engine		
Manufacturer:	Caterpillar	
Model:	C27	
Manufacture date:	2011	
Maximum capacity:	1,214 BHP (750 kW) 2.25 L/cylinder	EPA Tier 2 technologies Good combustion practices
Maximum operation:	4 hr/day and 60 hr/yr [(c)]	
Fuel:	ultra-low sulfur diesel	
Fuel consumption:	53.6 gph	
Fire pump engine		
Manufacturer:	Cummins	
Model:	CFP9E-F30	
Manufacture date:	2010	
Maximum capacity:	305 BHP (235 kW) 1.48 L/cylinder	EPA Tier 3 technologies Good combustion practices
Maximum operation:	2 hr/day and 40 hr/yr [(c)]	
Fuel:	ultra-low sulfur diesel	
Fuel consumption:	15.8 gph	
Cooling tower		
Manufacturer:	GEA	
Model:	7-cell, counterflow wet	Drift eliminators
Manufacture date:	2010	Good operating practices
Maximum water flow:	76,151 gpm	
Maximum TDS:	5,000 mg/L	
Dry chemical storage silos (3)		
Manufacturer:	Silosafe	
Manufacture date:	2010	Bin vent filters
Maximum capacities:	6500, 2200, and 2090 ft^3	Good operating practices
Maximum loading operation:	2 hr/day and 48 hr/yr per silo	
Above-ground fuel storage tanks (2)		
Manufacture date:	2013	Lids or other appropriate closure
Maximum capacity:	250 gal each (diesel/gasoline)	

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

4.2 Insignificant Emissions Units Based on Size or Production Rate

No emissions unit or activity that is subject to an applicable requirement may qualify as an insignificant emissions unit or activity. As required by IDAPA 58.01.01.317.01.b, emissions units or activities determined to be insignificant based on size or production rate were listed in the permit application and identified in Section 8 of the permit, with applicable regulatory citations.

4.3 Emission Inventories

Table 4.2 and Table 4.3 summarize the emission inventories of federally regulated criteria pollutant, hazardous air pollutant (HAP) pollutant, and greenhouse gas (GHG) pollutant emissions. Emissions are in tons per year (T/yr) and represent the facility-wide potential to emit.

Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design (IDAPA 58.01.01.006.86). Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. The use of the control equipment, fuels, and operational schedules listed in Table 4.1 were used in the development of the emission inventories. Refer to Appendix B – Emission Inventories for the emission estimates provided in the application.

Table 4.2 Potential to Emit Criteria Pollutants [a]

Emissions Units		NO_x		CO		VOC		$PM_{2.5}$[b]/PM_{10}[c]		SO_2		Pb		GHG CO_2e
		lb/hr	T/yr[d]	lb/hr	T/yr[d]	lb/hr	T/yr[d]	lb/hr	T/yr[d]	lb/hr	T/yr[d]	lb/hr	T/yr[d]	T/yr[d]
CT and duct burner[e]	peak[f]	20.10	88.0	12.24	278.10	7.01	74.90	12.55	49.46	3.41	13.44	0.02	0.05	1,055,941
	LL[g]	452.78		70.35		18.91								
	SU/SD[h]	304.56		2510.00		186.60								
Emergency generator[i]		12.80	0.39	7.00	0.21	0.80	0.02	0.40	0.01	0.01	0.01			42
Fire pump[j]		2.00	0.03	1.70	0.03	0.10	0.00	0.10	0.00	0.00	0.01			7
Cooling tower[k]								0.81	3.50					
Dry chemical storage silos[l]								0.13	0.01					
Above-ground fuel storage tanks						0.03	0.15							
Paved roads[m]								0.20	0.01					
Unpaved roads[m]								0.27	0.01					
Facility Totals		**467.58**	**88.42**	**2518.70**	**278.35**	**187.53**	**75.07**	**14.46**	**53.00**	**3.42**	**13.47**	**0.02**	**0.05**	**1,055,990**

a) Short-term (lb/hr) and annual (T/yr) emission estimates assumed the use of BACT and were based on daily and annual limits. Emission estimates were derived from the application and statement of basis for PTC No. P-2009.0092, issued June 25, 2010, and from updated estimates provided in the Tier I application.
b) Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
c) Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers, including condensable particulate as defined in IDAPA 58.01.01.006.
d) Tons per any consecutive 12-calendar-month period.
e) Annual totals assume a maximum fuel usage of 793.1 MM lb/yr, which accounts for continuous duct-firing under full-load for 6,902 hours, 253 hot startups, 45 warm startups, 7 cold startups, and 305 shutdowns annually.
f) At steady-state and ≥ 60% of full-load operating conditions.
g) At steady-state and < 60% of full-load operating conditions; defined as low-load (LL) operating condition.
h) At startup or shutdown (SU/SD) operating conditions. Emissions were estimated as the total emissions divided by the duration of each event. Annual totals include 253 hot startup, 45 warm startup, 7 cold startup, and 305 shutdown events per year (equivalent to 982 hr/yr of operation).
i) Limited to 4 hr/day and 60 hr/yr operation for maintenance and testing purposes.
j) Limited to 2 hr/day and 40 hr/yr operation for maintenance and testing purposes.
k) Assumes total dissolved solids (TDS) of blowdown of less than or equal to 5,000 mg/L and a circulating flow rate of 76,151 gpm.
l) Total emissions from the dry chemical storage silos. Annual totals assume each silo is loaded up to 48 hours per year.
m) Fugitive emission sources.

Table 4.3 Potential to Emit Hazardous Air Pollutants and Toxic Air Pollutants

Pollutant	Category TAP/HAP	PTE lb/hr[(a)]	HAP PTE T/yr[(d)]
1,3-Butadiene	HAP, 586 TAP[(c)]	8.26E-04	3.62E-03
2-Methylnaphthalene	HAP, 586 TAP[(c)(e)]	5.24E-06	
3-Methylcholanthrene	HAP, 586 TAP[(c)(e)]	3.93E-07	
7,12-Dimethylbenz(a)anthracene	HAP, 586 TAP[(c)(e)]	3.50E-06	
Acenaphthene	HAP, 586 TAP[(c)(e)]	6.46E-07	
Acenaphthylene	HAP, 586 TAP[(c)(e)]	9.08E-07	
Acetaldehyde	HAP, 586 TAP[(c)]	7.68E-02	3.36E-01
Acrolein	HAP, 585 TAP[(b)]	1.39E-02	5.38E-02
Ammonia	585 TAP[(b)]	1.86E+01	
Anthracene	HAP, 586 TAP[(c)(e)]	6.02E-07	
Arsenic	HAP, 586 TAP[(c)]	4.37E-05	1.91E-04
Barium	585 TAP[(b)]	1.07E-03	
Benzene	HAP, 586 TAP[(c)]	2.39E-02	1.05E-01
Benzo(a)pyrene	HAP, 586 TAP[(c)(e)]	2.77E-07	
Benzo(g,h,i)perylene	HAP, 586 TAP[(c)(e)]	2.94E-07	
Beryllium	HAP, 586 TAP[(c)]	2.62E-06	1.15E-05
Cadmium	HAP, 586 TAP[(c)]	2.40E-04	1.05E-03
Chromium	HAP, 585 TAP[(b)]	3.40E-04	3.06E-04
Cobalt	HAP, 585 TAP[(b)]	2.04E-05	8.04E-05
Copper	585 TAP[(b)]	2.06E-04	
Cyclohexane	585 TAP[(b)]	4.57E-05	
Dichlorobenzene (o- and 1,4-)	HAP, 585 TAP[(b)]	2.91E-04	1.15E-03
Ethyl alcohol	585 TAP[(b)]	5.48E-04	
Ethyl benzene	HAP, 585 TAP[(b)]	6.83E-02	2.69E-01
Fluoranthene	HAP, 586 TAP[(c)(e)]	9.12E-07	
Fluorene	HAP, 586 TAP[(c)(e)]	1.49E-06	
Formaldehyde	HAP, 586 TAP[(c)]	1.38E+00	6.04E+00
Hexane	HAP, 585 TAP[(b)]	4.37E-01	1.72E+00
Manganese	HAP, 585 TAP[(b)]	9.22E-05	3.64E-04
Mercury	HAP, 585 TAP[(b)]	6.31E-05	2.49E-04
Molybdenum	585 TAP[(b)]	2.67E-04	
Naphthalene	585 TAP[(b)]	4.03E-03	
Naphthalene (as PAH)	HAP, 586 TAP[(c)(e)]	2.94E-03	
Nickel	HAP, 586 TAP[(c)]	4.59E-04	2.01E-03
Nitrous oxide	585 TAP[(b)]	6.93E+00	
Pentane	585 TAP[(b)]	6.31E-01	
Phenanthrene	HAP, 586 TAP[(c)(e)]	6.04E-06	
Propylene oxide	HAP, 585 TAP[(b)]	6.21E-02	2.72E-01
POM (7-PAH Group)[(e)]	HAP, 586 TAP[(c)(e)]	2.74E-06	
Pyrene	HAP, 586 TAP[(c)(e)]	1.32E-06	
Selenium	HAP, 585 TAP[(b)]	5.83E-06	2.30E-05
Sulfuric acid mist	585 TAP[(b)]	2.61E-01	
Toluene	HAP, 585 TAP[(b)]	2.81E-01	1.10E+00
1,2,4-Trimethylbenzene	585 TAP[(b)]	1.03E-05	
Vanadium	585 TAP[(b)]	5.71E-04	
Xylenes	HAP, 585 TAP[(b)]	1.39E-01	5.38E-01
Zinc	585 TAP[(b)]	7.04E-03	
Total POM	HAP	6.89E-03	3.02E-02
Individual HAP			6.04
Total HAP			12.28

a) Short-term (lb/hr) and annual (T/yr) emission estimates were based on daily and annual limits. Emission estimates were derived from the application and statement of basis for PTC No. P-2009.0092, issued June 25, 2010, and from updated estimates provided in the Tier I application.
b) Non-carcinogenic substance listed in IDAPA 58.01.01.585.
c) Carcinogenic substance listed in IDAPA 58.01.01.586.
d) Tons per consecutive 12-calendar-month period.
e) Polyaromatic hydrocarbons (PAH) and polycyclic organic matter (POM) are defined in IDAPA 58.01.01.586.

Facility-wide uncontrolled and potential pre-control device emissions of NO_x and CO were estimated to exceed 100 tons per year. Uncontrolled emissions are defined as emissions that have not been treated by control equipment (IDAPA 58.01.01.006.129). Potential pre-control device emissions are defined as potential to emit, except that emission reductions achieved by the applicable control device shall not be taken into account (40 CFR 64.2(a)(3)).

The emission inventories were reviewed by DEQ and appear to accurately reflect the potential emissions from the facility. Greenhouse gases have been recognized as regulated pollutants with respect to the Title V program in this initial Tier I permitting action.

5. EMISSION LIMITS AND MRRR

This section contains requirements applicable to this facility. Monitoring, recordkeeping and reporting requirements typically follow each applicable requirement, and state how compliance is to be demonstrated.

This section is divided into several subsections:

- Facility-wide conditions
- Combustion turbine (CT) and duct burner conditions
- Emergency generator engine and fire pump engine conditions
- Cooling tower conditions
- Dry chemical storage silo conditions
- Insignificant activities
- Acid Rain conditions
- General provisions

The first subsection lists the requirements that apply facility-wide. Subsequent subsections list the requirements that apply to specific emissions units and pollutant-emitting activities. The final subsections identify insignificant activities, incorporate acid rain program requirements, and contain general provisions that apply to all facilities subject to Tier I operating permit requirements.

MRRR

Typically following each applicable requirement (permit condition) is a periodic monitoring regime for demonstrating compliance with the applicable requirement. A periodic monitoring regime consists of monitoring, recordkeeping and/or reporting requirements (MRRR). If an applicable requirement does not include sufficient MRRR to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate MRRR sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit in accordance with 40 CFR 70.6(a)(3)(i)(B). This is referred to as "gap filling". In addition to the specific MRRR described under each permit condition, generally applicable facility-wide conditions and general provisions are also required.

To minimize the length of this document, the permit condition and MRRR summaries that follow have been paraphrased. Refer to the permit for the complete requirements. Copies of O&M manuals, monitoring plans, and protocols are provided for reference in Appendix D – Operation and Maintenance Manual and in Appendix E – Monitoring Plans & Protocols.[2]

State Enforceability

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

Federal Enforceability

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

Section 1 – Acronyms, Units, and Chemical Nomenclature

This permit section describes the acronyms and nomenclature used in this permit.

Section 2 – Permit Scope

Permit Conditions 2.1 – 2.2

These permit conditions describe the purpose of the permit, the underlying permits incorporated into the permit, and the emission sources and control equipment regulated by the permit.

Section 3 – Facility-Wide Conditions

Permit Conditions 3.1 – 3.4

Permit Condition 3.1 incorporates fugitive dust emission limits in accordance with IDAPA 58.01.01.650-651.

MRRR include the following (Permit Conditions 3.2 – 3.4):

- Inspect sources of fugitive emissions quarterly.
- Monitor and record the frequency and methods used to control fugitive dust emissions.
- Conduct facility-wide inspections and take corrective action when appropriate.
- Record fugitive dust complaints received, fugitive dust inspections, and corrective actions.

Permit Conditions 3.5 – 3.6

Permit Condition 3.5 incorporates "state-only" requirements for the control of odors in accordance with IDAPA 58.01.01.776.01.

MRRR include the following (Permit Condition 3.6):

- Maintain records of all odor complaints received and the corrective action taken in response to the complaint.
- Take appropriate corrective action when appropriate.
- Record corrective actions.

Permit Conditions 3.7 – 3.9

Permit Condition 3.7 incorporates visible emissions limits in accordance with IDAPA 58.01.01.625.

MRRR include the following (Permit Conditions 3.8 – 3.9):

- Inspect potential sources of visible emissions quarterly.
- Conduct facility-wide inspections and take corrective action when appropriate (and/or complete Method 9).
- Maintain records of inspection, opacity tests, and corrective actions.
- Report exceedances.

Permit Condition 3.10

Permit Condition 3.10 incorporates process weight-based PM standards for process equipment in accordance with IDAPA 58.01.01.700-703. Process equipment (as defined in IDAPA 58.01.01.006) includes the cooling tower and dry chemical storage silos. Compliance with design and operational requirements for this equipment was considered adequate to ensure compliance with the minimum allowable process weight-based PM emission limitation specified in IDAPA 58.01.01.700.02 of 1 lb/hr (PM emissions were estimated to be 0.81 lb/hr for the cooling tower and 0.13 lb/hr per silo loaded).

MRRR include the following:

- Use drift eliminators (Permit Condition 6.1 – 6.3).
- Monitor cooling water solids content and flow rate (Permit Conditions 6.4 – 6.5).
- Use of bin vent filters (Permit Conditions 7.1 – 7.3).

Permit Condition 3.11

This permit condition incorporates PM emission limits from fuel-burning equipment as defined in IDAPA 58.01.01.006, in accordance with IDAPA 58.01.01.676. The duct burner is used for the primary purpose of producing heat and power by indirect heat transfer when operating as a combined cycle. Compliance with the PM_{10} emission limit was deemed adequate to ensure compliance with this limit; the PM_{10} emission limit for the CT and the duct burner (combined) was previously determined to be the more stringent limitation.[1] A copy of the limit stringency evaluation is provided in Appendix C – Limit Stringency Evaluation. Refer to discussion concerning MRRR for Permit Condition 4.8 for relevant MRRR. (Although compliance with the PM_{10} emission limit was deemed adequate to ensure compliance with this limit, Permit Conditions 3.11 and 4.8 were not requested to be streamlined into a single permit condition.)

MRRR include the following:

- Comply with the PM_{10} emission limit (Permit Condition 4.8).

Permit Condition 3.12 – 3.13

Permit Condition 3.12 incorporates sulfur content limits for distillate fuel oil, in accordance with IDAPA 58.01.01.725.

MRRR include the following:

- Record fuel oil sulfur content (Permit Condition 3.13).
- Use ultra-low-sulfur diesel (ULSD) fuels (Permit Condition 5.10); the NSPS ULSD sulfur content limit of 15 ppm (0.0015% by weight) is more stringent than the limits under IDAPA 58.01.01.725.

Permit Conditions 3.14 – 3.16

These permit conditions require MRRR to ensure compliance with BACT emission limits (Permit Conditions 4.2 – 4.4), BACT work practices (Permit Conditions 4.12, 5.7, 6.3, and 7.3), the ammonia injection flow rate limit (Permit Conditions 4.19 and 4.32), and manufacturer's specifications (Permit Conditions 5.6 and 5.8). Copies of O&M manuals are provided in Appendix D – Operation and Maintenance Manual.[2]

Permit Conditions 3.17 – 3.22

These permit conditions incorporate excess emission procedures and requirements in accordance with IDAPA 58.01.01.130-136.

MRRR include the following (Permit Conditions 3.17 – 3.22):

- Record, notify, and report excess emission events, including any assessed during monitoring (Permit Conditions 4.20 – 4.30, 4.32, 4.36 – 4.39, 6.4 – 6.5, and 9.5 – 9.18) or during testing (Permit Conditions 3.8, 4.33 – 4.35, and 5.13).

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1 Additional regulatory review concerning these permit conditions and applicable requirements is provided in the Statement of Basis for PTC No. P-2009.0092, Idaho DEQ, June 25, 2010 (2009AAG5203[v4]).

2 Copies of O&M manuals, monitoring plans, and monitoring protocols are provided in Appendix D – Operation and Maintenance Manual and in Appendix E – Monitoring Plans & Protocols, referenced from "Tier I Permit Application Supplemental Information," Idaho Power, April 30, 2013 (2013AAG700).

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

Permit Condition 3.23 – 3.26

These permit conditions specify performance test methodology in accordance with IDAPA 58.01.01.157.

The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing (Permit Condition 3.25).

MRRR include the following (Permit Conditions 3.23 – 3.26, 3.27, 4.33 – 4.35, and 5.13):

- Notify, record, and report performance testing results.

Permit Condition 3.27

This permit condition incorporates NSPS general provisions in accordance with 40 CFR 60, Subpart A, as required by Subparts KKKK and IIII.[1]

Permit Condition 3.28

This permit condition incorporates federal requirements by reference in accordance with IDAPA 58.01.01.107.

No specific MRRR were required for this facility-wide condition beyond the requirements explicitly incorporated into the permit.

Permit Conditions 3.29 – 3.32

These permit conditions establish generally applicable MRRR for monitoring, recordkeeping, and reporting.

Permit Condition 3.33

This permit condition incorporates open burning requirements, in accordance with IDAPA 58.01.01.600-623.

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

Permit Condition 3.34

This permit condition incorporates National Emission Standards for Asbestos in accordance with 40 CFR 61, Subpart M.

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

Permit Condition 3.35

This permit condition incorporates accidental release prevention requirements in accordance with 40 CFR 68.

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

Permit Condition 3.36

This permit condition incorporates standards for refrigerants and their substitutes in accordance with 40 CFR 82.

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

Section 4 – Combustion Turbine and Duct Burner

Permit Conditions 4.1, 4.2 – 4.4, 4.5, 4.10 – 4.14, 4.20 – 4.22, 4.26 – 4.27, 4.33 – 4.34

Permit Condition 4.1 defines startup, shutdown, and low-load events, in terms of percent load and event duration, for the purposes of determining the applicable BACT emission limit (Permit Conditions 4.2 – 4.4) for the CT and duct burner over each averaging period, and for blending BACT emission limits when appropriate. A maximum duration was not defined for low-load events; operation at low-load is inherently limited by the annual NO_x and CO emission limits (Permit Condition 4.5) and the annual fuel usage limit (Permit Condition 4.17).

Permit Conditions 4.2 – 4.4 establish BACT emission limits for the CT and the duct burner (combined).[1]

Permit Condition 4.5 establishes annual emission limits for the CT and the duct burner. These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations.[1]

MRRR include the following:

- Monitor and record startup, shutdown, and low-load events (Permit Condition 4.20).
- Install, operate, and maintain SCR and CatOx control equipment (Permit Conditions 4.10 – 4.11).
- Install, certify, operate, and maintain NO_x and CO CEMS (Permit Conditions 4.13 – 4.14).
- Continuously monitor and record NO_x and CO CEMS data, and assess and report excess emissions (Permit Conditions 4.20 – 4.22, 4.26 – 4.27, and 3.17 – 3.22).
- Comply with O&M manual requirements (Permit Conditions 4.12, and 3.14 – 3.16), and with monitoring protocols and methodologies (Permit Conditions 4.21, 4.24, 4.26, 9.14, and 9.17).[2]
- Perform compliance testing (Permit Conditions 4.33 – 4.34, and 3.23 – 3.26).

Permit Condition 4.6

This permit condition incorporates NO_x emission limits for the CT and the duct burner from NSPS Subpart KKKK.[1]

Permit Condition 4.7

This permit condition incorporates SO_2 emission limits from NSPS Subpart KKKK.[1]

Permit Condition 4.8

This permit condition establishes a PM_{10} emission limit for the CT and the duct burner (combined). This limit corresponds to the potential emission rate (PTE) used in preconstruction modeling compliance demonstrations.[1]

MRRR include the following:

- Perform compliance testing (Permit Conditions 4.33 – 4.34, and 3.23 – 3.26).

Permit Conditions 4.9, 4.18, 4.19, and 4.32

This permit condition incorporates an ammonia emission limit for the CT and the duct burner, based on the manufacturer's emission guarantee for ammonia slip and to ensure proper SCR control equipment maintenance and operation (Permit Condition 3.14).

MRRR include the following:

- Monitor and record the ammonia injection flow rate (Permit Conditions 4.18, 4.19, and 4.32).
- Comply with O&M manual requirements (Permit Conditions 3.14 – 3.16), and with monitoring protocols and methodologies (Permit Condition 4.32) for ammonia injection flow rate monitoring.[2]
- Perform compliance testing (Permit Conditions 4.33 – 4.34, and 3.23 – 3.26).

Permit Condition 4.15

This permit condition incorporates general compliance requirements from NSPS Subpart KKKK.[1]

Permit Condition 4.16 and 4.30

Permit Condition specifies the fuel to be used in the CT and the duct burner and limits the fuel sulfur content.

MRRR include the following:

- Monitor fuel sulfur content (Permit Condition 4.30).

Permit Condition 4.17 and 4.31

Permit Condition 4.17 incorporates annual limits on fuel usage for the CT and the duct burner. These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations.[1]

MRRR include the following:

- Monitor and record fuel usage (Permit Condition 4.31).

Permit Conditions 4.23 – 4.25

These permit conditions incorporate NO_x CEMS monitoring requirements from NSPS Subpart KKKK.[1,2]

Permit Conditions 4.28 – 4.29

These permit conditions incorporate sulfur content monitoring requirements from NSPS Subpart KKKK.[1]

Permit Conditions 4.33 – 4.34

These permit conditions require performance testing to demonstrate compliance with BACT emission limits (Permit Condition 4.2 - 4.4), the PM_{10} emission limit (Permit Condition 4.8), the ammonia emission limit (Permit Condition 4.9), and the visible emission limit (Permit Condition 3.7), in accordance with IDAPA 58.01.01.211.04.

Test conditions are specified and test methods are referenced (Permit Conditions 4.33 – 4.34, and 3.23 – 3.26). Alternative test conditions or methods may be approved by DEQ in accordance with IDAPA 58.01.01.157. The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing (Permit Condition 3.25).

Permit Condition 4.35

This permit condition incorporates SO_2 performance test requirements from NSPS Subpart KKKK.[1]

Permit Condition 4.36 – 4.39

These permit conditions incorporate reporting requirements from NSPS Subpart KKKK.[1]

Section 5 – Emergency Generator Engine and Fire Pump Engine

Permit Conditions 5.1 – 5.2, 5.7

These permit conditions incorporate BACT emission limits and work practices for the emergency generator engine and the fire pump engine. These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations.[1]

MRRR include the following:

- Comply with the monitoring, recordkeeping, and other requirements set forth in NSPS Subpart IIII[1] (Permit Conditions 5.3 – 5.4, 5.6, 5.8 – 5.9, and 5.13).
- Comply with O&M manual requirements for minimizing emissions (Permit Conditions 5.7, 3.14 – 3.16).[2]

Permit Condition 5.3

This permit condition incorporates emission standards for the emergency generator engine from NSPS Subpart IIII.[1]

Permit Condition 5.4

This permit condition incorporates emission standards for the fire pump engine from NSPS Subpart IIII.[1]

Permit Condition 5.5, 5.11 – 5.12

Permit Condition 5.5 incorporates limits on hours of operation for the emergency generator engine and fire pump engine for purposes of maintenance and testing. These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations.[1]

MRRR include the following:

- Monitor and record hours of operation (Permit Conditions 5.6, 5.9, 5.11 – 5.12).

Permit Condition 5.6

This permit condition incorporates compliance requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII.[1]

Permit Condition 5.8

This permit condition incorporates operating and maintenance requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII.[1]

Permit Condition 5.9

This permit condition incorporates monitoring requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII.[1]

Permit Condition 5.10

This permit condition incorporates fuel specifications for the emergency generator engine and fire pump engine from NSPS Subpart IIII.[1]

BACT determinations assumed the use of fuel meeting these specifications. These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations.[1]

Permit Condition 5.13

This permit condition incorporates testing requirements for the emergency generator engine and fire pump engine from NSPS Subpart IIII.[1]

The permittee is encouraged to submit performance test protocol to DEQ for approval prior to any performance testing (Permit Condition 3.25).

Section 6 – Cooling Tower

Permit Conditions 6.1 – 6.5

Permit Conditions 6.1 and 6.3 incorporate BACT requirements for minimizing emissions from the cooling tower.[1]

Permit Condition 6.2 requires operation of the drift eliminators to ensure compliance with BACT and process weight rate emission limits (Permit Conditions 3.10, 6.1, and 6.3).

MRRR include the following:

- Operate the control equipment (Permit Conditions 6.1 – 6.2).
- Comply with manufacturer's recommendations and O&M manual requirements (Permit Conditions 6.1, 6.3, and 3.14 – 3.16).[2]
- Monitor cooling water solids content and flow rate (Permit Conditions 6.4 – 6.5). These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations. BACT determinations assumed the use of cooling tower water meeting these specifications.

Section 7 – Dry Chemical Storage Silos

Permit Conditions 7.1 – 7.3

Permit Conditions 7.1 and 7.3 incorporate BACT requirements for minimizing emissions from the dry chemical storage silos.[1]

Permit Condition 7.2 requires operation of the bin vent filters to ensure compliance with BACT and process weight rate emission limits (Permit Conditions 3.10, 7.1, and 7.3).

MRRR include the following:

- Operate the control equipment (Permit Conditions 7.1 – 7.2).
- Comply with manufacturer's recommendations and O&M manual requirements (Permit Conditions 7.1, 7.3, and 3.14 – 3.16).[2]

Section 8 – Insignificant Activities

This section lists emissions units and pollutant-emitting activities determined to be insignificant activities based on size or production, in accordance with IDAPA 58.01.01.317.01.b. Refer to the Insignificant Emissions Units Based on Size or Production Rate section for information concerning these determinations.

Section 9 – Acid Rain

Permit Conditions 9.1 – 9.3

These permit conditions incorporate SO_2 requirements and allowance requirements under the Acid Rain Program and in accordance with IDAPA 58.01.01.322.12 for the CT and the duct burner. Refer to the Acid Rain Permit (40 CFR 72-75) section for information concerning Acid Rain Program regulatory review and MRRR.

Permit Condition 9.4

This permit condition incorporates NO_x requirements under the Acid Rain Program. Refer to the Acid Rain Permit (40 CFR 72-75) section for information concerning Acid Rain Program regulatory review and MRRR.

Permit Conditions 9.5 – 9.6

These permit conditions incorporate operating and maintenance requirements under the Acid Rain Program. Refer to the Acid Rain Permit (40 CFR 72-75) section for information concerning Acid Rain Program regulatory review and MRRR.

Permit Conditions 9.7 – 9.18

These permit conditions incorporate monitoring, recordkeeping, and reporting requirements under the Acid Rain Program. Refer to the Acid Rain Permit (40 CFR 72-75) section for information concerning Acid Rain Program regulatory review and MRRR.

Permit Condition 9.19 – 9.20

These permit conditions incorporate general liability and prohibition provisions under the Acid Rain program. Refer to the Acid Rain Permit (40 CFR 72-75) section for information concerning Acid Rain Program regulatory review and MRRR.

Section 10 – General Provisions

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

Permit Conditions 10.1 – 10.3

These permit conditions incorporate general compliance provisions as follows:

- Duty to comply with permit terms and conditions.
- Duty to halt or reduce an activity.
- Duty to supplement or correct application, upon becoming aware of omissions or incorrect information.

Permit Conditions 10.4 – 10.5

These permit conditions incorporate provisions for permit reopening as follows:

- Permits may be revised, reopened, revoked, reissued, or terminated for cause.
- Permit conditions are not stayed if a request for permit action or notification of noncompliance is filed.

Permit Condition 10.6

This permit condition incorporates the provision that property rights and exclusive privileges are not conveyed by the permit.

Permit Conditions 10.7 – 10.8

These permit conditions incorporate provisions for information requests as follows:

- Duty to provide information and records upon request.

Permit Condition 10.9

This permit condition incorporates the provision that permit requirements are severable.

Permit Conditions 10.10 – 10.11

These permit conditions incorporate provisions for changes requiring permit revision or notice as follows:

- Permits must be obtained before construction or modification of a stationary source, facility, major facility, or major modification.
- Changes not addressed or prohibited require permit revision if such changes are subject to any of the specified requirements.

Permit Conditions 10.12 – 10.13

These permit conditions incorporate provisions for federal and state enforceability of permit conditions as follows:

- All permit conditions are federally enforceable unless specified in the permit as "state-only".
- "State-only" permit conditions are enforceable in accordance with state law.

Permit Condition 10.14

This permit condition incorporates provisions allowing for DEQ access to the facility for inspection.

Permit Condition 10.15

This permit condition incorporates a provision requiring compliance with applicable requirements that become effective after permit issuance.

Permit Condition 10.16

This permit condition incorporates a provision requiring payment of Tier I/Title V annual registration fees.

Permit Condition 10.17

This permit condition incorporates a provision requiring certification of documents submitted to DEQ by a responsible official.

Permit Conditions 10.18 – 10.19

These permit conditions incorporate provisions for permit renewal and permit continuation as follows:

- Renewal applications are required 6-18 months before permit expiration.
- The permit remains in effect until a renewal permit has been issued or denied.

Permit Condition 10.20

This permit condition incorporates a permit shield provision.

Permit Condition 10.21

This permit condition incorporates a provision for compliance schedules and progress reports as follows:

- For each applicable requirement for which the source is not in compliance, the permittee shall comply with a compliance schedule.
- For each applicable requirement that will become effective during the permit term, the permittee shall comply with the required compliance schedule (if applicable).
- For each applicable requirement that will become effective during the permit term without a required compliance schedule, the permittee shall meet such requirements on a timely basis.
- For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.

Permit Condition 10.22

This permit condition incorporates a provision for periodic compliance certification as follows:

- Compliance certification forms for all emissions units shall be submitted at least annually, or more frequently if applicable.
- Compliance certifications shall be submitted to DEQ, and a copy submitted to EPA.

Permit Condition 10.23

This permit condition incorporates a provision for no false statements.

Permit Condition 10.24

This permit condition incorporates a provision for no tampering with monitoring devices or methods.

Permit Condition 10.25

This permit condition incorporates a provision for semiannual monitoring reports as follows:

- Reports shall be submitted at least every six months.

Permit Condition 10.26

This permit condition incorporates a provision for prompt reporting of deviations and excess emissions.

Permit Condition 10.27

This permit condition incorporates an exception from permit revision for approved programs and process changes when provided for in the permit.

Permit Condition 10.28

This permit condition incorporates an exception from noncompliance for emergencies under the conditions specified in IDAPA 58.01.01.332.02.

6. REGULATORY REVIEW

6.1 Attainment Designation (40 CFR 81.313)

The facility is located in Payette County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and ozone, and is located within Air Quality Control Region 63. There are no Class I areas within 10 kilometers of the facility. Refer to 40 CFR 81.313 for additional information.

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

The facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because it has the potential to emit 100 tons per year or more of CO (278.35 T/yr).

Because the facility is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr, it is a designated facility as defined in IDAPA 58.01.01.006, and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

In accordance with IDAPA 58.01.01.313.01.b, a complete application was submitted to DEQ for an initial Tier I operating permit within 12 months of commencing operation. Refer to the Application Scope & Chronology section for a listing of relevant dates.

6.3 PSD Classification (40 CFR 52.21)

Because the facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input (designated facility) which has the potential to emit 100 tons per year or more of CO (278.35 T/yr), it is classified as an existing major stationary source as defined in §52.21(b)(1)(i)(a) and in accordance with IDAPA 58.01.01.205.01.

Because the facility is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr, it is a designated facility as defined in IDAPA 58.01.01.006, and fugitive emissions were included when determining the major facility classification in accordance with IDAPA 58.01.01.008.10.c.i.

6.4 NSPS Applicability (40 CFR 60)

The facility is subject to 40 CFR 60, Subpart KKKK – Standards of Performance for Stationary Combustion Turbines, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and Subpart A – General Provisions.[1]

In accordance with 40 CFR 60.4305(a), the CT, HRSG, and duct burner are affected sources subject to Subpart KKKK, because the CT has a heat input at peak load greater than 10 MMBtu/hr (HHV), and because the construction date was after February 18, 2005.

In accordance with 40 CFR 60.4200(a)(2), the emergency generator and fire pump are affected sources subject to 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, because the construction dates were after July 1, 2006.

In accordance with 40 CFR 60.4305(b), the CT is exempt from the requirements of Subpart GG, and the HRSG and duct burner are exempt from the requirements of 40 CFR 60, Subparts Da, Db, and Dc – Standards of Performance for Steam Generating Units, because the CT, HRSG, and duct burner are regulated under Subpart KKKK.

Refer to Table 4.1 for the manufacture dates of each emissions unit.

6.5 NESHAP Applicability (40 CFR 61)

The facility and emission sources are not subject to NESHAP requirements in 40 CFR 61.

6.6 MACT Applicability (40 CFR 63)

The emergency generator and fire pump are new stationary reciprocating internal combustion engines (RICE) sources subject to 40 CFR 63, Subpart ZZZZ.

In accordance with 40 CFR 63.6590(c)(1), because these sources are subject to regulation under 40 CFR 60, Subpart IIII, and they commenced construction after June 12, 2006, no further requirements are applicable under 40 CFR 63, Subpart ZZZZ. Refer to Table 4.1 for the manufacture dates of each emissions unit.

The facility is not subject to 40 CFR 63, Subpart Q – NESHAP for Industrial Process Cooling Towers or to 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines, because the facility is not a major source of HAP emissions.

6.7 CAM Applicability (40 CFR 64)

Although pre-control device emissions of NO_x and CO could potentially exceed major source thresholds, the CT and duct burner are exempt from CAM requirements because applicable NSPS emission limits were established after November 15, 1990, and because applicable BACT and annual emission limits require continuous compliance monitoring (CEMS).

40 CFR 64 .... Compliance Assurance Monitoring

40 CFR 64.2 .... Applicability.

(a) General applicability. *Except for backup utility units that are exempt under paragraph (b)(2) of this section, the requirements of this part shall apply to a pollutant-specific emissions unit at a major source that is required to obtain a part 70 or 71 permit if the unit satisfies all of the following criteria:*

(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof), other than an emission limitation or standard that is exempt under paragraph (b)(1) of this section;

(2) The unit uses a control device to achieve compliance with any such emission limitation or standard; and

(3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source. For purposes of this paragraph, "potential pre-control device emissions" shall have the same meaning as "potential to emit," as defined in §64.1, except that emission reductions achieved by the applicable control device shall not be taken into account.

(b) Exemptions —

(1) Exempt emission limitations or standards. *The requirements of this part shall not apply to any of the following emission limitations or standards:*

(i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act.

(ii) Stratospheric ozone protection requirements under title VI of the Act.

(iii) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.

(iv) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources.

(v) An emissions cap that meets the requirements specified in §70.4(b)(12) or §71.6(a)(13)(iii) of this chapter.

(vi) Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1. The exemption provided in this paragraph (b)(1)(vi) shall not apply if the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device (such as a surface coating line controlled by an incinerator for which continuous compliance is determined by calculating emissions on the basis of coating records and an assumed control device efficiency factor based on an initial performance test; in this example, this part would apply to the control device and capture system, but not to the remaining elements of the coating line, such as raw material usage).

...

The facility is a major source that is required to obtain a Part 70 permit (Tier I operating permit); refer to the Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70) and PSD Classification (40 CFR 52.21) sections for additional information.

As shown in Table 6.1, the CT and duct burner emissions units share potentially-applicable emission limitations and standards for regulated air pollutants (i.e., NO_x and CO emission limits), use control devices to achieve compliance with these limitations and standards (SCR for NO_x and CatOx for CO), and have pre-control device emissions (NO_x and CO) equal to or greater than 100 percent of the amount required for a source to be classified as a major source. However, each of these emission limits and standards have been determined to be exempt from Compliance Assurance Monitoring (CAM) for one or more of the following reasons:

- they are Section 111 limits or standards established after November 15, 1990 (i.e., NSPS Subpart KKKK), and/or
- they are emissions limits or standards for which continuous compliance is required in the Tier I operating permit (40 CFR 70).

Therefore, in accordance with 40 CFR 64.2(b)(1), the CT and duct burner are exempt from CAM requirements.

Table 6.1 CT and Duct Burner Compliance Assurance Monitoring Applicability

Description	Parameters	Potentially-Applicable Limits / Standards	Exemption	Continuous Compliance Determination Method
BACT (40 CFR 52.21)	NO_x	2.0 ppm, except 96 ppm during low-load/startup/shutdown	40 CFR 64.2(b)(1)(vi)	NO_x CEMS
	CO	2.0 ppm, except 24.5 ppm during low-load and 2,510 lb/hr during startup/shutdown		CO CEMS
Annual	NO_x	88 T/yr	40 CFR 64.2(b)(1)(vi)	NO_x CEMS
	CO	278.1 T/yr		CO CEMS
NSPS (Section 111)	NO_x	15 ppm, except 96 ppm during low-load	40 CFR 64.2(b)(1)(i); 40 CFR 64.2(b)(1)(vi)	NO_x CEMS

It is noted that the CatOx control device is also used to achieve compliance with VOC BACT emission limits. Because pre-control device emissions of VOC were estimated below the major source threshold (100 T/yr), CAM requirements were not applicable.[3] VOC and CO emissions are primarily attributed to incomplete combustion, and although direct continuous monitoring of VOC emissions is not required, continuous monitoring of CO and NO_x emissions (CO and NO_x CEMS) serve as indicators of compliance with VOC BACT (Permit Conditions 4.2 – 4.3), combustion (Permit Condition 4.12), and CatOx operation (Permit Condition 4.11) requirements.

3 "Source Emissions Testing Report, Idaho Power Company," Air Pollution Testing Inc., received July 31, 2012 (2012AAI1607, 2013AAG636). Based on upstream and low-load VOC concentrations measured during performance testing, uncontrolled (pre-CatOx) VOC emissions were not estimated to exceed 100 T/yr. Refer to summary Tables 4.5 and 4.9 and supporting information.

6.8 Acid Rain Permit (40 CFR 72-75)

Because the combustion turbine and the duct burner are new units which commenced commercial operation after November 15, 1990, these units are subject to Acid Rain Program requirements. The combustion turbine and the duct burner (CT1) qualify as an affected source, as a facility, as utility units, and as new units as defined under 40 CFR 72.2. Applicable requirements from the Acid Rain permit application[4] and from 40 CFR 72-75 have been incorporated into Section 9 – Acid Rain of the permit.

40 CFR 72 ....PERMITS REGULATION

40 CFR 72, Subpart A ....Acid Rain Program General Provisions

40 CFR 72.2 ....Definitions.

...

Acid Rain emissions limitation *means:*

(1) For purposes of sulfur dioxide emissions:

(i) The tonnage equivalent of the allowances authorized to be allocated to the affected units at a source for use in a calendar year under section 404(a)(1), (a)(3), and (h) of the Act, or the basic Phase II allowance allocations authorized to be allocated to an affected unit for use in a calendar year, or the allowances authorized to be allocated to an opt-in source under section 410 of the Act for use in a calendar year;

(ii) As adjusted:

(A) By allowances allocated by the Administrator pursuant to section 403, section 405 (a)(2), (a)(3), (b)(2), (c)(4), (d)(3), and (h)(2), and section 406 of the Act;

(B) By allowances allocated by the Administrator pursuant to subpart D of this part; and thereafter

(C) By allowance transfers to or from the compliance account for that source that were recorded or properly submitted for recordation by the allowance transfer deadline as provided in §73.35 of this chapter, after deductions and other adjustments are made pursuant to §73.34(c) of this chapter; and

(2) For purposes of nitrogen oxides emissions, the applicable limitation under part 76 of this chapter.

...

Acid Rain permit or permit *means the legally binding written document or portion of such document, including any permit revisions, that is issued by a permitting authority under this part and specifies the Acid Rain Program requirements applicable to an affected source and to the owners and operators and the designated representative of the affected source or the affected unit.*

Acid Rain Program *means the national sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established in accordance with title IV of the Act, this part, and parts 73, 74, 75, 76, 77, and 78 of this chapter.*

...

Administrator *means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.*

...

Affected source *means a source that includes one or more affected units.*

...

Affected unit *means a unit that is subject to any Acid Rain emissions reduction requirement or Acid Rain emissions limitation under §72.6 or part 74 of this chapter.*

...

---

[4] A copy of the Acid Rain Permit application (2010AAG111) is provided in Attachment A to the Statement of Basis.

Allowance *means an authorization by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during or after a specified calendar year.*

Allowance deduction, or deduct *when referring to allowances, means the permanent withdrawal of allowances by the Administrator from an Allowance Tracking System compliance account to account for the number of tons of SO_2 emissions from the affected units at an affected source for the calendar year, for tonnage emissions estimates calculated for periods of missing data as provided in part 75 of this chapter, or for any other allowance surrender obligations of the Acid Rain Program.*

Allowances held or hold allowances *means the allowances recorded by the Administrator, or submitted to the Administrator for recordation in accordance with §73.50 of this chapter, in an Allowance Tracking System account.*

...

Commence commercial operation *means to have begun to generate electricity for sale, including the sale of test generation.*

Commence construction *means that an owner or operator has either undertaken a continuous program of construction or has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.*

Commence operation *means to have begun any mechanical, chemical, or electronic process, including start-up of an emissions control technology or emissions monitor or of a unit's combustion chamber.*

...

Continuous emission monitoring system or CEMS *means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2, NO_x, or CO_2 emissions or stack gas volumetric flow rate. The following are the principal types of continuous emission monitoring systems required under part 75 of this chapter. Sections 75.10 through 75.18, and §75.71(a) of this chapter indicate which type(s) of CEMS is required for specific applications:*

(1) *A sulfur dioxide monitoring system, consisting of an SO_2 pollutant concentration monitor and an automated DAHS. An SO_2 monitoring system provides a permanent, continuous record of SO_2 emissions in units of parts per million (ppm);*

(2) *A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS. A flow monitoring system provides a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);*

(3) *A nitrogen oxides (NO_x) emission rate (or NO_x-diluent) monitoring system, consisting of a NO_x pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated DAHS. A NO_x-diluent monitoring system provides a permanent, continuous record of: NO_x concentration in units of parts per million (ppm), diluent gas concentration in units of percent O_2 or CO_2 (%O_2 or CO_2), and NO_x emission rate in units of pounds per million British thermal units (lb/mmBtu);*

(4) *A nitrogen oxides concentration monitoring system, consisting of a NO_x pollutant concentration monitor and an automated DAHS. A NO_x concentration monitoring system provides a permanent, continuous record of NO_x emissions in units of parts per million (ppm). This type of CEMS is used only in conjunction with a flow monitoring system to determine NO_x mass emissions (in lb/hr) under subpart H of part 75 of this chapter;*

(5) *A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and the automated DAHS. A carbon dioxide monitoring system provides a permanent, continuous record of CO_2 emissions in units of percent CO_2 (%CO_2); and*

(6) *A moisture monitoring system, as defined in §75.11(b)(2) of this chapter. A moisture monitoring system provides a permanent, continuous record of the stack gas moisture content, in units of percent H_2O (%H_2O)*

...

Designated representative *means a responsible natural person authorized by the owners and operators of an affected source and of all affected units at the source or by the owners and operators of a combustion source or process source, as evidenced by a certificate of representation submitted in accordance with subpart B of this part, to represent and legally bind each owner and operator, as a matter of Federal law, in matters pertaining to the Acid*

Rain Program. Whenever the term "responsible official" is used in part 70 of this chapter, in any other regulations implementing title V of the Act, or in a State operating permit program, it shall be deemed to refer to the "designated representative" with regard to all matters under the Acid Rain Program.

...

Diluent gas *means a major gaseous constituent in a gaseous pollutant mixture, which in the case of emissions from fossil fuel-fired units are carbon dioxide and oxygen.*

Diluent gas monitor *means that component of the continuous emission monitoring system that measures the diluent gas concentration in a unit's flue gas.*

...

Facility *means any institutional, commercial, or industrial structure, installation, plant, source, or building.*

...

Flow monitor *means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.*

Flue *means a conduit or duct through which gases or other matter are exhausted to the atmosphere.*

...

Fuel supply agreement *means a legally binding agreement between a new IPP or a firm associated with a new IPP and a fuel supplier that establishes the terms and conditions under which the fuel supplier commits to provide fuel to be delivered to the new IPP.*

...

Gas-fired *means:*

(1) For all purposes under the Acid Rain Program, except for part 75 of this chapter, the combustion of:

(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel), for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and

(ii) Any fuel, except coal or solid or liquid coal-derived fuel, for the remaining heat input, if any.

(2) For purposes of part 75 of this chapter, the combustion of:

(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel) for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and

(ii) Fuel oil, for the remaining heat input, if any.

(3) For purposes of part 75 of this chapter, a unit may initially qualify as gas-fired if the designated representative demonstrates to the satisfaction of the Administrator that the requirements of paragraph (2) of this definition are met, or will in the future be met, through one of the following submissions:

(i) For a unit for which a monitoring plan has not been submitted under §75.62 of this chapter, the designated representative submits either:

(A) Fuel usage data for the unit for the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under §75.62; or

(B) If a unit does not have fuel usage data for one or more of the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under §75.62, the unit's designated fuel usage; all available fuel usage data (including the percentage of the unit's heat input derived from the combustion of gaseous fuels), beginning with the date on which the unit commenced commercial operation; and the unit's projected fuel usage.

(ii) For a unit for which a monitoring plan has already been submitted under §75.62, that has not qualified as gas-fired under paragraph (3)(i) of this definition, and whose fuel usage changes, the designated representative submits either:

(A) *Three calendar years of data following the change in the unit's fuel usage, showing that no less than 90.0 percent of the unit's average annual heat input during the previous three calendar years, and no less than 85.0 percent of the unit's annual heat input during any one of the previous three calendar years, is from the combustion of gaseous fuels and the remaining heat input is from the combustion of fuel oil; or*

(B) *A minimum of 720 hours of unit operating data following the change in the unit's fuel usage, showing that no less than 90.0 percent of the unit's heat input is from the combustion of gaseous fuels and the remaining heat input is from the combustion of fuel oil, and a statement that this changed pattern of fuel usage is considered permanent and is projected to continue for the foreseeable future.*

(iii) *If a unit qualifies as gas-fired under paragraph (3)(i) or (ii) of this definition, the unit is classified as gas-fired as of the date of the submission under such paragraph.*

(4) *For purposes of part 75 of this chapter, a unit that initially qualifies as gas-fired under paragraph (3)(i) or (ii) of this definition must meet the criteria in paragraph (2) of this definition each year in order to continue to qualify as gas-fired. If such a unit combusts only gaseous fuel and fuel oil but fails to meet such criteria for a given year, the unit no longer qualifies as gas-fired starting January 1 of the year after the first year for which the criteria are not met. If such a unit combusts fuel other than gaseous fuel or fuel oil and fails to meet such criteria in a given year, the unit no longer qualifies as gas-fired starting the day after the first day for which the criteria are not met. If a unit failing to meet the criteria in paragraph (2) of this definition initially qualified as a gas-fired unit under paragraph (3) of this definition, the unit may qualify as a gas-fired unit for a subsequent year only if the designated representative submits the data specified in paragraph (3)(ii)(A) of this definition.*

...

Gaseous fuel *means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat.*

...

Low mass emissions unit *means an affected unit that is "gas-fired" or "oil-fired" (as defined in this section), and that qualifies to use the low mass emissions excepted methodology in §75.19 of this chapter.*

...

Owner or operator *means any person who is an owner or who operates, controls, or supervises an affected unit, affected source, combustion source, or process source and shall include, but not be limited to, any holding company, utility system, or plant manager of an affected unit, affected source, combustion source, or process source.*

...

Phase II *means the Acid Rain Program period beginning January 1, 2000, and continuing into the future thereafter.*

Phase II unit *means any affected unit, except an affected unit under part 74 of this chapter, that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation during Phase II only.*

Pipeline natural gas *means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.*

...

Source *means any governmental, institutional, commercial, or industrial structure, installation, plant, building, or facility that emits or has the potential to emit any regulated air pollutant under the Act, provided that one or more combustion or process sources that have, under §74.4(c) of this chapter, a different designated representative than the designated representative for one or more affected utility units at a source shall be treated as being included in a separate source from the source that includes such utility units for purposes of parts 72 through 78 of this chapter, but shall be treated as being included in the same source as the source that includes such utility units for purposes of section 502(c) of the Act. For purposes of section 502(c) of the Act, a "source", including a "source" with multiple units, shall be considered a single "facility."*

...

Ton or tonnage *means any "short ton" (i.e., 2,000 pounds). For the purpose of determining compliance with the Acid Rain emissions limitations and reduction requirements, total tons for a year shall be calculated as the sum of all recorded hourly emissions (or the tonnage equivalent of the recorded hourly emissions rates) in accordance with part 75 of this chapter, with any remaining fraction of a ton equal to or greater than 0.50 ton deemed to equal one ton and any fraction of a ton less than 0.50 ton deemed not to equal any ton.*

An abbreviated summary of applicable definitions has been provided above. Because the CT and the duct burner are only permitted to combust pipeline-quality natural gas in the CT and the duct burner (Permit Condition 4.16), these qualify as gas-fired units combusting gaseous fuels (refer to §75.11 below).

Permit Condition 4.16 references definitions from this paragraph, and these definitions are incorporated by reference in Permit Condition 3.28.

40 CFR 72.6 ....Applicability.

(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:

(1) A unit listed in table 1 of §73.10(a) of this chapter.

(2) A unit that is listed in table 2 or 3 of §73.10 of this chapter and any other existing utility unit, except a unit under paragraph (b) of this section.

(3) A utility unit, except a unit under paragraph (b) of this section, that:

(i) Is a new unit; or

...

Because the combustion turbine and the duct burner are new units which commenced commercial operation after November 15, 1990, these units are subject to Acid Rain Program requirements. The combustion turbine and the duct burner (CT1) qualify as an affected source, as a facility, as utility units, and as new units as defined under 40 CFR 72.2.

40 CFR 72.9 ....Standard requirements.

(a) 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 this part in accordance with the deadlines specified in §72.30;

(ii) Submit in a timely manner a complete reduced utilization plan if required under §72.43; and

(iii) 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.

The permittee submitted an Acid Rain permit application for CT1. Because CT1 commenced commercial operation after November 15, 1990, it is a new unit as defined in §72.2.

Applicable requirements from the Acid Rain permit application and from 40 CFR 72-75 have been incorporated into Section 9 – Acid Rain of the permit. Refer to the Application Scope & Chronology section for a listing of relevant dates concerning submittal of the Acid Rain permit application.

(b) 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 part 75 of this chapter.*

(2) The emissions measurements recorded and reported in accordance with part 75 of this chapter 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 part 75 of this chapter 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.*

Permit Condition 9.7 includes the requirements of this paragraph.

(c) 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 §73.34(c) of this chapter) 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 limitation 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 (c)(1) of this section as follows:

(i) Starting January 1, 1995, an affected unit under §72.6(a)(1);

(ii) Starting on or after January 1, 1995 in accordance with §§72.41 and 72.43, an affected unit under §72.6(a) (2) or (3) that is a substitution or compensating unit;

(iii) Starting January 1, 2000, an affected unit under §72.6(a)(2) that is not a substitution or compensating unit; or

(iv) Starting on the later of January 1, 2000 or the deadline for monitor certification under part 75 of this chapter, an affected unit under §72.6(a)(3) that is not a substitution or compensating unit.

(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 (c)(1)(i) of this section, 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 §§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.

Permit Conditions 9.1 and 9.3 include the requirements of this paragraph.

(d) 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.*

Permit Condition 9.4 includes the requirements of this paragraph.

(e) 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 part 77 of this chapter.*

(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 part 77 of this chapter; and

(ii) Comply with the terms of an approved offset plan, as required by part 77 of this chapter.

Permit Condition 9.11 includes the requirements of this paragraph.

(f) 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 §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.*

(ii) All emissions monitoring information, in accordance with part 75 of this chapter; provided *that to the extent that 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.

(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 subpart I of this part and part 75 of this chapter.

Permit Condition 9.13 includes the requirements of this paragraph.

(g) 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 §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 this part, parts 73, 74, 75, 76, 77, and 78 of this chapter, 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.

...

Permit Condition 9.19 includes the requirements of this paragraph.

40 CFR 72, Subpart D ....Acid Rain Compliance Plan and Compliance Options

40 CFR 72.40 ....General.

(a) For each affected unit included in an Acid Rain permit application, a complete compliance plan shall:

(1) For sulfur dioxide emissions, certify that, as of the allowance transfer deadline, the designated representative will hold allowances in the compliance account of the source where the unit is located (after deductions under §73.34(c) of this chapter) not less than the total annual emissions of sulfur dioxide from the affected units at the source. The compliance plan may also specify, in accordance with this subpart, one or more of the Acid Rain compliance options.

(2) For nitrogen oxides emissions, certify that the unit will comply with the applicable emission limitation under §76.5, §76.6, or §76.7 of this chapter or shall specify one or more Acid Rain compliance options, in accordance with part 76 of this chapter.

...

Because the CT1 is not a coal-fired utility unit, the Part 76 emission limitations referenced in §72.40(a)(2) were not applicable. Permit Conditions 9.1 and 9.4 include applicable requirements from this paragraph.

40 CFR 72, Subpart E ....Acid Rain Permit Contents

40 CFR 72.50 ....General.

(a) Each Acid Rain permit (including any draft or proposed Acid Rain permit) will contain the following elements in a format prescribed by the Administrator:

(1) All elements required for a complete Acid Rain permit application under §72.31 of this part, as approved or adjusted by the permitting authority;

(2) The applicable Acid Rain emissions limitation for sulfur dioxide; and

(3) The applicable Acid Rain emissions limitation for nitrogen oxides.

(b) Each Acid Rain permit is deemed to incorporate the definitions of terms under §72.2 of this part.

40 CFR 72.31 ....Information requirements for Acid Rain permit applications.

A complete Acid Rain permit application shall include the following elements in a format prescribed by the Administrator:

(a) Identification of the affected source for which the permit application is submitted;

(b) Identification of each Phase I unit at the source for which the permit application is submitted for Phase I or each affected unit (except for an opt-in source) at the source for which the permit application is submitted for Phase II;

(c) A complete compliance plan for each unit, in accordance with subpart D of this part;

(d) The standard requirements under §72.9; and

(e) If the Acid Rain permit application is for Phase II and the unit is a new unit, the date that the unit has commenced or will commence operation and the deadline for monitor certification.

As provided in §72.50(a)(1) and §72.31, the affected source and affected units and date of commencement of commercial operations are identified in Table 9.1. Initial monitor certification was completed as required within 180 days of commencement of commercial operation, in accordance with §75.4(b)(2).[3,5] The other referenced requirements are addressed in the relevant sections above.

Permit Conditions 9.1, 9.3, 9.4, 9.7, 9.11, 9.13, and 9.19 include applicable requirements from §72.50(a).

40 CFR 72.51 ....Permit shield.

Each affected unit operated in accordance with the Acid Rain permit that governs the unit and that was issued in compliance with title IV of the Act, as provided in this part and parts 73, 74, 75, 76, 77, and 78 of this chapter shall be deemed to be operating in compliance with the Acid Rain Program, except as provided in §72.9(g)(6).

General Provision 10.20 includes the permit shield, which addresses acid rain program requirements in accordance with IDAPA 58.01.01.322.15.m. Also with respect to the General Provisions, Permit Condition 10.18 requires renewal of the Acid Rain permit in accordance with §72.30(c) and §72.73(b)(2), and Permit Condition 10.4 allows re-opening for cause in accordance with §72.85 and IDAPA 58.01.01.386.01.b.

5 NO_x, CO, O_2, and CO_2 CEMS were certified on June 17, 2012 in conformance with RATA requirements in 40 CFR 75, Appendix B and 40 CFR 60, Appendix B. "Source Emissions Testing Report, Idaho Power Company," Air Pollution Testing Inc., received July 31, 2012 (2012AAI1608). Notice of commercial operation was provided on April 9 and 16, 2012 (2012AAI771, 2012AAI776).

40 CFR 75 ....CONTINUOUS EMISSION MONITORING

40 CFR 75, Subpart A ....General

40 CFR 75.5 ....Prohibitions.

(a) *A violation of any applicable regulation in this part by the owners or operators or the designated representative of an affected source or an affected unit is a violation of the Act.*

(b) *No owner or operator of an affected unit shall operate the unit without complying with the requirements of §§75.2 through 75.75 and appendices A through G to this part.*

(c) *No owner or operator of an affected unit shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained the Administrator's prior written approval in accordance with §§75.23, 75.48 and 75.66.*

(d) *No owner or operator of an affected unit shall operate the unit so as to discharge, or allow to be discharged, emissions of SO_2, NO_x or CO_2 to the atmosphere without accounting for all such emissions in accordance with the provisions of §§75.10 through 75.19.*

(e) *No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2, NO_x, or CO_2 emissions discharged to the atmosphere, except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to §75.21 and appendix B of this part.*

(f) *No owner or operator of an affected unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, the continuous opacity monitoring system, or any other approved emission monitoring system under this part, except under any one of the following circumstances:*

   (1) *During the period that the unit is covered by an approved retired unit exemption under §72.8 of this chapter that is in effect; or*

   (2) *The owner or operator is monitoring emissions from the unit with another certified monitoring system or an excepted methodology approved by the Administrator for use at that unit that provides emissions data for the same pollutant or parameter as the retired or discontinued monitoring system; or*

   (3) *The designated representative submits notification of the date of recertification testing of a replacement monitoring system in accordance with §§75.20 and 75.61, and the owner or operator recertifies thereafter a replacement monitoring system in accordance with §75.20.*

Permit Condition 9.20 includes the requirements of these paragraphs.

40 CFR 75, Subpart B ....Monitoring Provisions

40 CFR 75.10 ....General operating requirements.

(a) Primary Measurement Requirement. *The owner or operator shall measure opacity, and all SO_2, NO_x, and CO_2 emissions for each affected unit as follows:*

   (1) *To determine SO_2 emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a SO_2 continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm), volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hr) discharged to the atmosphere, except as provided in §§75.11 and 75.16 and subpart E of this part;*

   (2) *To determine NO_x emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a NO_x-diluent continuous emission monitoring system (consisting of a NO_x pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NO_x concentration (in ppm), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_x emission rate (in lb/mmBtu) discharged to the atmosphere, except as provided in §§75.12 and 75.17 and subpart E of this part. The owner or operator shall account for total NO_x emissions, both NO and NO_2, either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2;*

   (3) *The owner or operator shall determine CO_2 emissions by using one of the following options, except as provided in §75.13 and subpart E of this part:*

(i) *The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a CO_2 continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 concentration (in ppm or percent), volumetric gas flow (in scfh), and CO_2 mass emissions (in tons/hr) discharged to the atmosphere;*

(ii) *The owner or operator shall determine CO_2 emissions based on the measured carbon content of the fuel and the procedures in appendix G of this part to estimate CO_2 emissions (in ton/day) discharged to the atmosphere; or*

(iii) *The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a flow monitoring system and a CO_2 continuous emission monitoring system that uses an O_2 concentration monitor to determine CO_2 emissions (according to the procedures in appendix F of this part) with an automated data acquisition and handling system for measuring and recording O_2 concentration (in percent), CO_2 concentration (in percent), volumetric gas flow (in scfh), and CO_2 mass emissions (in tons/hr) discharged to the atmosphere;*

(4) *The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements in this part, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) discharged to the atmosphere, except as provided in §§75.14 and 75.18; and*

(5) *A single certified flow monitoring system may be used to meet the requirements of paragraphs (a)(1) and (a)(3) of this section. A single certified diluent monitor may be used to meet the requirements of paragraphs (a)(2) and (a)(3) of this section. A single automated data acquisition and handling system may be used to meet the requirements of paragraphs (a)(1) through (a)(4) of this section.*

(b) Primary Equipment Performance Requirements. *The owner or operator shall ensure that each continuous emission monitoring system required by this part meets the equipment, installation, and performance specifications in appendix A to this part; and is maintained according to the quality assurance and quality control procedures in appendix B to this part; and shall record SO_2 and NO_x emissions in the appropriate units of measurement (*i.e., *lb/hr for SO_2 and lb/mmBtu for NO_x).*

(c) Heat Input Rate Measurement Requirement. *The owner or operator shall determine and record the heat input rate, in units of mmBtu/hr, to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in appendix F to this part.*

(d) Primary equipment hourly operating requirements. *The owner or operator shall ensure that all continuous emission and opacity monitoring systems required by this part are in operation and monitoring unit emissions or opacity at all times that the affected unit combusts any fuel except as provided in §75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to §75.21 and appendix B of this part, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to §75.20. The owner or operator shall also ensure, subject to the exceptions above in this paragraph, that all continuous opacity monitoring systems required by this part are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable Federal, State, or local regulation, or permit. The owner or operator shall ensure that the following requirements are met:*

(1) *The owner or operator shall ensure that each continuous emission monitoring system is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, CO_2 concentration, O_2 concentration, CO_2 mass emissions (if applicable), NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to §75.21 and appendix B of this part, or backups of data from the data acquisition and handling system, or recertification, pursuant to §75.20. The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.*

(2) *The owner or operator shall ensure that each continuous opacity monitoring system is capable of completing a minimum of one cycle of sampling and analyzing for each successive 10-sec period and one cycle of data recording for each successive 6-min period. The owner or operator shall reduce all opacity data to 6-min averages calculated in accordance with the provisions of part 51, appendix M of this chapter, except where the applicable State implementation plan or operating permit requires a different averaging period, in which case the State requirement shall satisfy this Acid Rain Program requirement.*

(3) *Failure of an SO_2, CO_2, or O_2 emissions concentration monitor, NO_x concentration monitor, flow monitor, moisture monitor, or NO_x-diluent continuous emission monitoring system to acquire the minimum number of data points for calculation of an hourly average in paragraph (d)(1) of this section shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. For a NO_x-diluent monitoring system, an hourly average NO_x emission rate in lb/mmBtu is valid only if the minimum number of data points is acquired by both the NO_x pollutant concentration monitor and the diluent monitor (O_2 or CO_2). For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O_2 on a wet-basis and a dry-basis, an hourly average percent moisture value is valid only if the minimum number of data points is acquired for both the wet-and dry-basis measurements. If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part.*

(e) Optional backup monitor requirements. *If the owner or operator chooses to use two or more continuous emission monitoring systems, each of which is capable of monitoring the same stack or duct at a specific affected unit, or group of units using a common stack, then the owner or operator shall designate one monitoring system as the primary monitoring system, and shall record this information in the monitoring plan, as provided for in §75.53. The owner or operator shall designate the other monitoring system(s) as backup monitoring system(s) in the monitoring plan. The backup monitoring system(s) shall be designated as redundant backup monitoring system(s), non-redundant backup monitoring system(s), or reference method backup system(s), as described in §75.20(d). When the certified primary monitoring system is operating and not out-of-control as defined in §75.24, only data from the certified primary monitoring system shall be reported as valid, quality-assured data. Thus, data from the backup monitoring system may be reported as valid, quality-assured data only when the backup is operating and not out-of-control as defined in §75.24 (or in the applicable reference method in appendix A of part 60 of this chapter) and when the certified primary monitoring system is not operating (or is operating but out-of-control). A particular monitor may be designated both as a certified primary monitor for one unit and as a certified redundant backup monitor for another unit.*

(f) Minimum measurement capability requirement. *The owner or operator shall ensure that each continuous emission monitoring system is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of appendix A to this part.*

(g) Minimum recording and recordkeeping requirements. *The owner or operator shall record and the designated representative shall report the hourly, daily, quarterly, and annual information collected under the requirements of this part as specified in subparts F and G of this part.*

Because the permittee has elected to use compliance options for gaseous fuel and for gas-fired units to determine SO_2 emissions under §75.11(e)[6] and is exempted from opacity monitoring under §75.14(c), the requirements of §75.10(a)(1) and §75.10(a)(4) were not applicable and were not included as permit conditions. §75.10(a)(5) contains optional compliance methods which were not included as a permit condition.

Permit Condition 4.13, 9.5, 9.9, and 9.10 include applicable requirements from these paragraphs.

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6 Based on permittee's request (referencing PTC Condition 51) to use annual fuel sampling methodology for pipeline natural gas in accordance with Appendix D, Table D-5 to 40 CFR 75; "Facility Draft – Comment Descriptions," Idaho Power, received April 2, 2010 (2010AAG671). Data provided by permittee using sampling methods under Section 2.3.3.1.2 of Appendix D to 40 CFR 75, >90% methane content by mass and 1,028.7 Btu/scf gross dry real calorific value were measured; "Extended Natural Gas Analysis (*DHA) Main Page," Empact Analytical Systems Inc., received May 6, 2013 (2013AAI1094). Using ASTM Method D-5504, <0.5 gr/100 scf sulfur content was measured in all samples; Appendix 2 – Fuel Gas Analysis to "Source Emissions Testing Report – Idaho Power Company," Air Pollution Testing Inc., received July 31, 2012 (2012AAI1607).

40 CFR 75.11 ....Specific provisions for monitoring SO_2 emissions.

...

(d) Gas-fired and oil-fired units. *The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in §72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall measure and record SO_2 emissions:*

   (1) By meeting the general operating requirements in §75.10 for an SO_2 continuous emission monitoring system and flow monitoring system. If this option is selected, the owner or operator shall comply with the applicable provisions in paragraph (e)(1), (e)(2), or (e)(3) of this section during hours in which the unit combusts only gaseous fuel;

   (2) By providing other information satisfactory to the Administrator using the applicable procedures specified in appendix D to this part for estimating hourly SO_2 mass emissions; or

   (3) By using the low mass emissions excepted methodology in §75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under §75.19(a) and (b). If this option is selected for SO_2, the LME methodology must also be used for NO_x and CO_2 when these parameters are required to be monitored by applicable program(s).

(e) Special considerations during the combustion of gaseous fuels. *The owner or operator of an affected unit that uses a certified flow monitor and a certified diluent gas (O_2 or CO_2) monitor to measure the unit heat input rate shall, during any hours in which the unit combusts only gaseous fuel, determine SO_2 emissions in accordance with paragraph (e)(1) or (e)(3) of this section, as applicable.*

   (1) If the gaseous fuel qualifies for a default SO_2 emission rate under Section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part, the owner or operator may determine SO_2 emissions by using Equation F-23 in appendix F to this part. Substitute into Equation F-23 the hourly heat input, calculated using the certified flow monitoring system and the certified diluent monitor (according to the applicable equation in section 5.2 of appendix F to this part), in conjunction with the appropriate default SO_2 emission rate from section 2.3.1.1, 2.3.2.1.1, or 2.3.6(b) of appendix D to this part. When this option is chosen, the owner or operator shall perform the necessary data acquisition and handling system tests under §75.20(c), and shall meet all quality control and quality assurance requirements in appendix B to this part for the flow monitor and the diluent monitor; or

...

Because the CT and the duct burner are only permitted to combust pipeline-quality natural gas in the CT and the duct burner (Permit Condition 4.16), these qualify as gas-fired units combusting gaseous fuels.[6] The permittee elected to measure and record SO_2 emissions using applicable procedures specified in Section 2.3.1.1 of Appendix D to 40 CFR 75, in accordance with §75.11(d)(2) and §75.11(e)(1).

Using the sampling methods specified in sections 2.3.3.1.2 and 2.3.4, a representative sample was obtained and analyzed for total sulfur content and for percent methane (and also gross calorific value), and the results demonstrated that the fuel meets the definition of pipeline natural gas in §72.2. As required in Appendix D, Table D-5 and Section 2.3.1.4(e), if the fuel qualifies as pipeline natural gas based on fuel sampling and analysis, on-going sampling of the fuel's sulfur content is required annually and whenever the fuel supply source changes.

Permit Condition 9.8 includes applicable requirements from this section.

40 CFR 75.12 ....Specific provisions for monitoring NO_x emission rate.

(a) Coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units. *The owner or operator shall meet the general operating requirements in §75.10 of this part for a NO_x continuous emission monitoring system (CEMS) for each affected coal-fired unit, gas-fired nonpeaking unit, or oil-fired nonpeaking unit, except as provided in paragraph (d) of this section, §75.17, and subpart E of this part. The diluent gas monitor in the NO_x-diluent CEMS may measure either O_2 or CO_2 concentration in the flue gases.*

(b) Moisture correction. *If a correction for the stack gas moisture content is needed to properly calculate the NO_x emission rate in lb/mmBtu, e.g., if the NO_x pollutant concentration monitor measures on a different moisture basis from the diluent monitor, the owner or operator shall either report a fuel-specific default moisture value for each unit operating hour, as provided in §75.11(b)(1), or shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in §75.11(b)(2). Notwithstanding this requirement, if*

Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to measure NO_x emission rate, the following fuel-specific default moisture percentages shall be used in lieu of the default values specified in §75.11(b)(1): 5.0%, for anthracite coal; 8.0% for bituminous coal; 12.0% for sub-bituminous coal; 13.0% for lignite coal; 15.0% for wood and 18.0% for natural gas (boilers, only).

(c) Determination of NO_x emission rate. *The owner or operator shall calculate hourly, quarterly, and annual NO_x emission rates (in lb/mmBtu) by combining the NO_x concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable) measurements according to the procedures in appendix F to this part.*

...

(e) Low mass emissions units. *Notwithstanding the requirements of paragraphs (a) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under §75.19(a) and (b) shall comply with one of the following:*

(1) *Meet the general operating requirements in §75.10 for a NO_x continuous emission monitoring system;*

(2) *Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or*

(3) *Use the low mass emissions excepted methodology in §75.19(c) for estimating hourly NO_x emission rate and hourly NO_x mass emissions, if applicable under §75.19(a) and (b). If this option is selected for NO_x, the LME methodology must also be used for SO_2 and CO_2 when these parameters are required to be monitored by applicable program(s).*

...

At the time of permit issuance, the CT and duct burner had not qualified as low mass emissions units.

Permit Condition 9.9 includes applicable requirements from this section.

40 CFR 75.13 ....Specific provisions for monitoring CO_2 emissions.

...

(b) Determination of CO_2 emissions using appendix G to this part. *If the owner or operator chooses to use the appendix G method, then the owner or operator shall follow the procedures in appendix G to this part for estimating daily CO_2 mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating CO_2, the owner or operator shall use the procedures in appendix G to this part to estimate both combustion-related emissions based on the measured carbon content of the fuel and the amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator shall calculate daily, quarterly, and annual CO_2 mass emissions (in tons) in accordance with the procedures in appendix G to this part.*

...

(d) Determination of CO_2 mass emissions from low mass emissions units. *The owner or operator of a unit that qualifies as a low mass emissions unit under §75.19(a) and (b) shall comply with one of the following:*

(1) *Meet the general operating requirements in §75.10 for a CO_2 continuous emission monitoring system and flow monitoring system;*

(2) *Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or*

(3) *Use the low mass emissions excepted methodology in §75.19(c) for estimating hourly CO_2 mass emissions, if applicable under §75.19(a) and (b). If this option is selected for CO_2, the LME methodology must also be used for NO_x and SO_2 when these parameters are required to be monitored by applicable program(s).*

The permittee has elected to utilize the Appendix G to 40 CFR 75 compliance option under §75.13(b).

At the time of permit issuance, the CT and duct burner had not qualified as low mass emissions units. The units also do not have add-on controls with sorbent injection.

Permit Condition 9.10 includes applicable requirements from these paragraphs.

40 CFR 75.14 .... *Specific provisions for monitoring opacity.*

...

(c) Gas-fired units. *The owner or operator of an affected unit that qualifies as gas-fired, as defined in §72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan is exempt from the opacity monitoring requirements of this part. Whenever a unit previously categorized as a gas-fired unit is recategorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system as required by paragraph (a) of this section by December 31 of the following calendar year.*

...

Because the CT and the duct burner are only permitted to combust pipeline-quality natural gas in the CT and the duct burner (Permit Condition 4.16), these qualify as gas-fired units combusting gaseous fuels as defined in §72.2 which are exempt from opacity monitoring requirements under §75.14.

40 CFR 75.16 .... *Special provisions for monitoring emissions from common, bypass, and multiple stacks for SO_2 emissions and heat input determinations.*

40 CFR 75.17 .... *Specific provisions for monitoring emissions from common, bypass, and multiple stacks for NO_x emission rate.*

40 CFR 75.18 .... *Specific provisions for monitoring emissions from common and by-pass stacks for opacity.*

40 CFR 75.19 .... *Optional SO_2, NO_x, and CO_2 emissions calculation for low mass emissions (LME) units.*

The permittee has elected to combine emissions for the CT1 (both CT and duct burner), and Subpart B contains applicable CEMS special and specific monitoring requirements which were referenced but not included as permit conditions. The CT1 does not have an applicable NO_x emission limitations under the Acid Rain program, does not have bypass stack(s) nor multiple stack(s) in use, and the CT1 has not been demonstrated as a LME.

In accordance with NO_x CEMS monitoring requirements (Permit Conditions 4.21, 4.24, 9.14, and 9.17), the permittee is required to have CEMS QA/QC and monitoring plans addressing requirements referenced in this section. Permit Conditions 9.8 and 9.9 incorporate applicable requirements from these sections by reference.

40 CFR 75, Subpart C .... *Operation and Maintenance Requirements*

40 CFR 75.20 .... *Initial certification and recertification procedures.*

40 CFR 75.21 .... *Quality assurance and quality control requirements.*

40 CFR 75.22 .... *Reference test methods.*

40 CFR 75.24 .... *Out-of-control periods and adjustment for system bias.*

Subpart C contains applicable CEMS Operation and Maintenance requirements which were referenced but not included as permit conditions.

In accordance with NO_x CEMS monitoring requirements (Permit Conditions 4.21, 4.24, 9.14, and 9.17), the permittee is required to have CEMS QA/QC and monitoring plans addressing requirements referenced in this section. Permit Condition 9.6 incorporates applicable requirements from these sections by reference.

40 CFR 75, Subpart D .... *Missing Data Substitution Procedures*

40 CFR 75.30 .... *General provisions.*

(a) Except as provided in §75.34, the owner or operator shall provide substitute data for each affected unit using a continuous emission monitoring system according to the missing data procedures in this subpart whenever the unit combusts any fuel and:

(1) A valid, quality-assured hour of SO_2 concentration data (in ppm) has not been measured and recorded for an affected unit by a certified SO_2 pollutant concentration monitor, or by an approved alternative monitoring method under subpart E of this part, except as provided in paragraph (d) of this section; or

(2) A valid, quality-assured hour of flow data (in scfh) has not been measured and recorded for an affected unit from a certified flow monitor, or by an approved alternative monitoring system under subpart E of this part; or

(3) A valid, quality-assured hour of NO_x emission rate data (in lb/mmBtu) has not been measured or recorded for an affected unit, either by a certified NO_x-diluent continuous emission monitoring system or by an approved alternative monitoring system under subpart E of this part; or

(4) A valid, quality-assured hour of CO_2 concentration data (in percent CO_2, or percent O_2 converted to percent CO_2 using the procedures in appendix F to this part) has not been measured and recorded for an affected unit, either by a certified CO_2 continuous emission monitoring system or by an approved alternative monitoring method under subpart E of this part; or

(5) A valid, quality-assured hour of NO_x concentration data (in ppm) has not been measured or recorded for an affected unit, either by a certified NO_x concentration monitoring system used to determine NO_x mass emissions, as defined in §75.71(a)(2), or by an approved alternative monitoring system under subpart E of this part; or

(6) A valid, quality-assured hour of CO_2 or O_2 concentration data (in percent CO_2, or percent O_2) used for the determination of heat input has not been measured and recorded for an affected unit, either by a certified CO_2 or O_2 diluent monitor, or by an approved alternative monitoring method under subpart E of this part; or

(7) A valid, quality-assured hour of moisture data (in percent H_2O) has not been measured or recorded for an affected unit, either by a certified moisture monitoring system or an approved alternative monitoring method under subpart E of this part. This requirement does not apply when a default percent moisture value, as provided in §§75.11(b) or 75.12(b), is used to account for the hourly moisture content of the stack gas; or

(8) A valid, quality-assured hour of heat input rate data (in mmBtu/hr) has not been measured and recorded for a unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part.

...

40 CFR 75.31 ....Initial missing data procedures.

40 CFR 75.32 ....Determination of monitor data availability for standard missing data procedures.

40 CFR 75.33 ....Standard missing data procedures for SO_2, NO_x, and flow rate.

40 CFR 75.34 ....Units with add-on emission controls.

40 CFR 75.35 ....Missing data procedures for CO_2.

40 CFR 75.36 ....Missing data procedures for heat input rate determinations.

40 CFR 75.37 ....Missing data procedures for moisture.

Subpart D, §75.31-37 contain applicable CEMS missing data substitution procedures which were referenced but not included as permit conditions.

In accordance with NO_x CEMS monitoring requirements (Permit Conditions 4.21, 4.24, 9.14, and 9.17), the permittee is required to have CEMS QA/QC and monitoring plans addressing requirements referenced in this section.

Permit Condition 9.12 incorporates applicable requirements from these sections by reference.

40 CFR 75, Subpart F ....*Recordkeeping Requirements*

40 CFR 75.53 ....*Monitoring plan.*

(a) General provisions. *(1) The provisions of paragraphs (e) and (f) of this section shall be met through December 31, 2008. The owner or operator shall meet the requirements of paragraphs (a), (b), (e), and (f) of this section through December 31, 2008, except as otherwise provided in paragraph (g) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a), (b), (g), and (h) of this section only. In addition, the provisions in paragraphs (g) and (h) of this section that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to January 1, 2009.*

(2) The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (f) or (h) of this section (as applicable), a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems, excepted methodology under §75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all unit SO_2 emissions, NO_x emissions, CO_2 emissions, and opacity are monitored and reported.

(b) Whenever the owner or operator makes a replacement, modification, or change in the certified CEMS, continuous opacity monitoring system, excepted methodology under §75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan, by the applicable deadline specified in §75.62 or elsewhere in this part.

...

(g) Contents of the monitoring plan. *The requirements of paragraphs (g) and (h) of this section shall be met on and after January 1, 2009. Notwithstanding this requirement, the provisions of paragraphs (g) and (h) of this section may be implemented prior to January 1, 2009, as follows. In 2008, the owner or operator may opt to record and report the monitoring plan information in paragraphs (g) and (h) of this section, in lieu of recording and reporting the information in paragraphs (e) and (f) of this section. Each monitoring plan shall contain the information in paragraph (g)(1) of this section in electronic format and the information in paragraph (g)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.*

...

(h) Contents of monitoring plan for specific situations. *The following additional information shall be included in the monitoring plan for the specific situations described:*

(1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO_2 mass emissions, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_x emission rate (using a fuel flowmeter), the designated representative shall include the following additional information for each fuel flowmeter system in the monitoring plan:

(i) Electronic. *(A) Parameter monitored;*

(B) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;

(C) Test method used to check the accuracy of each fuel flowmeter;

(D) Monitoring system identification code;

(E) The method used to demonstrate that the unit qualifies for monthly GCV sampling or for daily or annual fuel sampling for sulfur content, as applicable; and

(F) Activation date/hour and (if applicable) inactivation date/hour for the fuel flowmeter system;

(ii) Hardcopy. *(A) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of*

each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

(B) *For units using the optional default SO_2 emission rate for "pipeline natural gas" or "natural gas" in appendix D to this part, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to this part;*

(C) *For units using the 720 hour test under 2.3.6 of Appendix D of this part to determine the required sulfur sampling requirements, report the procedures and results of the test; and*

(D) *For units using the 720 hour test under 2.3.5 of Appendix D of this part to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test.*

(2) *For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in appendix E to this part for estimating NO_x emission rate, the designated representative shall include in the monitoring plan:*

(i) Electronic. *Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit, as defined in §72.2 of this chapter for the current calendar year or ozone season, including: capacity factor data for three calendar years (or ozone seasons) as specified in the definition of peaking unit in §72.2 of this chapter; the method of qualification used; and an indication of whether the data are actual or projected data. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the peaking unit qualification information in this paragraph (h)(2)(i).*

(ii) Hardcopy. *(A) A protocol containing methods used to perform the baseline or periodic NO_x emission test; and*

(B) *Unit operating parameters related to NO_x formation by the unit.*

(3) *For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the designated representative claims an opacity monitoring exemption under §75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under §75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.*

(4) *For each unit using the low mass emissions excepted methodology under §75.19 the designated representative shall include the following additional information in the monitoring plan that accompanies the initial certification application:*

(i) Electronic. *For each low mass emissions unit, report the results of the analysis performed to qualify as a low mass emissions unit under §75.19(c). This report will include either the previous three years actual or projected emissions. The following items should be included:*

(A) *Current calendar year of application;*

(B) *Type of qualification;*

(C) *Years one, two, and three;*

(D) *Annual and/or ozone season measured, estimated or projected NO_x mass emissions for years one, two, and three;*

(E) *Annual measured, estimated or projected SO_2 mass emissions (if applicable) for years one, two, and three; and*

(F) *Annual or ozone season operating hours for years one, two, and three.*

(ii) Hardcopy. *(A) A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;*

(B) *For units which use the long term fuel flow methodology under §75.19(c)(3), the designated representative must provide a diagram of the fuel flow to each affected unit or group of units and describe in detail the procedures used to determine the long term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;*

(C) *A statement that the unit burns only gaseous fuel(s) and/or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) and/or fuel oil and a list of the fuels that are projected to be burned;*

(D) *A statement that the unit meets the applicability requirements in §75.19(a) and (b); and*

(E) *Any unit historical actual, estimated and projected emissions data and calculated emissions data demonstrating that the affected unit qualifies as a low mass emissions unit under §75.19(a) and 75.19(b).*

(5) *For qualification as a gas-fired unit, as defined in §72.2 of this part, the designated representative shall include in the monitoring plan, in electronic format, the following: current calendar year, fuel usage data for three calendar years (or ozone seasons) as specified in the definition of gas-fired in §72.2 of this chapter, the method of qualification used, and an indication of whether the data are actual or projected data. On and after April 27, 2011, provide the activation date and deactivation date (if applicable) for the gas-fired unit qualification information in this paragraph (h)(5).*

(6) *For each monitoring location with a stack flow monitor that is exempt from performing 3-load flow RATAs (peaking units, bypass stacks, or by petition) the designated representative shall include in the monitoring plan an indicator of exemption from 3-load flow RATA using the appropriate exemption code.*

§75.53 contains applicable CEMS monitoring plan recordkeeping requirements which were referenced but not included as permit conditions.

In accordance with NO_x CEMS monitoring requirements (Permit Conditions 4.21, 4.24, 9.14, and 9.17), the permittee is required to have CEMS QA/QC and monitoring plans addressing requirements referenced in this section.

Permit Condition 9.14 incorporates applicable requirements from this section by reference.

40 CFR 75.57 .... General recordkeeping provisions.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

(a) Recordkeeping requirements for affected sources. *The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Unless otherwise provided, throughout this subpart the phrase "for each affected unit" also applies to each group of affected or nonaffected units utilizing a common stack and common monitoring systems, pursuant to §§75.16 through 75.18, or utilizing a common pipe header and common fuel flowmeter, pursuant to section 2.1.2 of appendix D to this part. The file shall contain the following information:*

...

(b) Operating parameter record provisions. *The owner or operator shall record for each hour the following information on unit operating time, heat input rate, and load, separately for each affected unit and also for each group of units utilizing a common stack and a common monitoring system or utilizing a common pipe header and common fuel flowmeter:*

...

(c) SO_2 emission record provisions. *The owner or operator shall record for each hour the information required by this paragraph for each affected unit or group of units using a common stack and common monitoring systems, except as provided under §75.11(e) or for a gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part or for a low mass emissions unit for which the owner or operator is using the optional low mass emissions methodology in §75.19(c) for estimating SO_2 mass emissions:*

...

(d) NO_x emission record provisions. *The owner or operator shall record the applicable information required by this paragraph for each affected unit for each hour or partial hour during which the unit operates, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part or a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in §75.19(c) for estimating NO_x emission rate. For each NO_x emission rate (in lb/mmBtu) measured by a NO_x-diluent monitoring system, or, if applicable, for each NO_x concentration (in ppm) measured by a NO_x concentration monitoring system used to calculate NO_x mass emissions under*

§75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

...

(e) CO_2 emission record provisions. *Except for a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in §75.19(c) for estimating CO_2 mass emissions, the owner or operator shall record or calculate CO_2 emissions for each affected unit using one of the following methods specified in this section:*

...

(2) As an alternative to paragraph (e)(1) of this section, the owner or operator may use the procedures in §75.13 and in appendix G to this part, and shall record daily the following information for CO_2 mass emissions:

(i) Date;

(ii) Daily combustion-formed CO_2 mass emissions (tons/day, rounded to the nearest tenth);

...

(g) Diluent record provisions. *The owner or operator of a unit using a flow monitor and an O_2 diluent monitor to determine heat input, in accordance with Equation F-17 or F-18 of appendix F to this part, or a unit that accounts for heat input using a flow monitor and a CO_2 diluent monitor (which is used only for heat input determination and is not used as a CO_2 pollutant concentration monitor) shall keep the following records for the O_2 or CO_2 diluent monitor:*

...

(h) Missing data records. *The owner or operator shall record the causes of any missing data periods and the actions taken by the owner or operator to correct such causes.*

Permit Condition 9.15 incorporates applicable requirements from this section by reference.

40 CFR 75.58 .... General recordkeeping provisions for specific situations.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

(a) [Reserved]

(b) Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls. *In accordance with §75.34, the owner or operator of an affected unit with add-on emission controls shall either record the applicable information in paragraph (b)(3) of this section for each hour of missing SO_2 concentration data or NO_x emission rate (in addition to other information), or shall record the information in paragraph (b)(1) of this section for SO_2 or paragraph (b)(2) of this section for NO_x through an automated data acquisition and handling system, as appropriate to the type of add-on emission controls:*

...

(c) Specific SO_2 emission record provisions for gas-fired or oil-fired units using optional protocol in appendix D to this part. *In lieu of recording the information in §75.57(c), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part for estimating SO_2 mass emissions:*

...

(f) Specific SO_2, NO_x, and CO_2 record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in §75.19. *In lieu of recording the information in §§75.57(b) through (e), the owner or operator shall record the following information for each affected low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in §75.19(c):*

...

Because the CT1 utilizes an add-on emission control (SCR) for the control of NO_x emissions, the relevant requirements of §75.58(b) were applicable. Because the permittee has elected to measure and record SO_2 emissions using applicable procedures specified in Section 2.3.1.1 of Appendix D to 40 CFR 75, the requirements of §75.58(c) were applicable.

Permit Condition 9.16 incorporates applicable requirements from this section by reference.

40 CFR 75.59 .... Certification, quality assurance, and quality control record provisions.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

(a) Continuous emission or opacity monitoring systems. *The owner or operator shall record the applicable information in this section for each certified monitor or certified monitoring system (including certified backup monitors) measuring and recording emissions or flow from an affected unit.*

...

(b) Excepted monitoring systems for gas-fired and oil-fired units. *The owner or operator shall record the applicable information in this section for each excepted monitoring system following the requirements of appendix D to this part or appendix E to this part for determining and recording emissions from an affected unit.*

...

(c) Except as otherwise provided in §75.58(b)(3)(i), for units with add-on SO_2 or NO_x emission controls following the provisions of §75.34(a)(1) or (a)(2), the owner or operator shall keep the following records on-site in the quality assurance/quality control plan required by section 1 of appendix B to this part:

...

(d) Excepted monitoring for low mass emissions units under §75.19(c)(1)(iv). *For oil-and gas-fired units using the optional SO_2, NO_x and CO_2 emissions calculations for low mass emission units under §75.19, the owner or operator shall record the following information for tests performed to determine a fuel and unit-specific default as provided in §75.19(c)(1)(iv):*

...

(e) DAHS Verification. *For each DAHS (missing data and formula) verification that is required for initial certification, recertification, or for certain diagnostic testing of a monitoring system, record the date and hour that the DAHS verification is successfully completed. (This requirement only applies to units that report monitoring plan data in accordance with §75.53(g) and (h).)*

Permit Condition 9.17 incorporates applicable requirements from this section by reference.

40 CFR 75.60 .... General provisions.

40 CFR 75.61 .... Notifications.

40 CFR 75.62 .... Monitoring plan submittals.

40 CFR 75.63 .... Initial certification or recertification application.

40 CFR 75.64 .... Quarterly reports.

Permit Condition 9.18 incorporates applicable requirements from sections §§75.60-75.64 by reference.

IDAPA 58.01.01.322.12................................ Permit Conditions Regarding Acid Rain Allowances.

(a) A permit condition prohibiting emissions exceeding any allowances that the source lawfully holds.

(b) No limit shall be placed on the number of allowances held by the source and no permit revisions shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided that such increases do not require a permit revision under any other applicable requirement.

(c) The source may not, however, use allowances as a defense to noncompliance with any other applicable requirement.

(d) Any such allowance shall be accounted for according to the procedures established in 40 CFR Part 72 and 40 CFR Part 73.

Permit Condition 9.2 includes the requirements of this subsection.

7. PUBLIC AND EPA REVIEW

7.1 Public Review and Comment

A public comment period was provided on the draft permit, statement of basis, and application, in accordance with IDAPA 58.01.01.364. During this period, no comments were submitted in response to DEQ's proposed action. Refer to the Application Scope & Chronology section for a listing of relevant dates.

7.2 EPA Review and Comment

A review and comment period was provided to EPA Region 10 on the proposed permit, statement of basis, and application, in accordance with IDAPA 58.01.01.366, and no comments were received. Refer to the Application Scope & Chronology section for a listing of relevant dates.

Appendix A – Acid Rain 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

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

Permit Requirements

STEP 3

Read the standard 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:

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 B – Emission Inventories

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

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

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

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

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

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

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

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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

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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

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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

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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

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

Ammonia Equation

$$NH_3\left[\frac{lb}{hr}\right] = \frac{NH_3[ppm] \cdot NH_3[MW] \cdot FFactor\left[\frac{dscf}{MMBtu}\right] \cdot Fuel\ Flow\left[\frac{MMBtu}{hr}\right]}{10^6 \cdot 335.6} \cdot \left(\frac{20.9}{20.9 - 15}\right)$$

Sulfuric Acid Equation

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

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,l)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,l)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

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

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

- *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]***

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

- *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]***

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

- *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]

Duct Burner GHG Emission Calculations

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

- *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]

Appendix C – Limit Stringency Evaluation

IDAPA 58.01.01.675-676
Fuel Burning Equipment—Particulate Matter

This regulation establishes particulate matter emission standards for fuel burning equipment. Fuel burning equipment is defined in IDAPA 58.01.01…as, "*Any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer.*

Emissions of particulate matter from fuel burning equipment that commence operation on or after October 1, 1979, with a maximum rated input of 10 MMBtu/hr or more, are subject to the emissions standards of IDAPA 58.01.01.675 and 676. Therefore, the combustion turbine will comply with the grain-loading standard for gas-fired sources when operating the duct burners. See Table 6-1.

Table 6-1: IDAPA Rule 677 PM Standard for Fuel Burning Equipment

Unit	*Gas Turbine with Duct Firing*
Fuel	Natural Gas
Rated Heat Input (MM Btu/hr)	2375.00
PM Emission Rate (lb/hr)	12.40
Exit/Flue Gas Flowrate Calculation	
F_d (Table 19-2, EPA Method 19) (dscf/MM Btu) [a,b]	8,710
Exit flowrate @ 0% O_2: (dscfm)	344,771
Exit flowrate @ 3% O_2: (dscfm) [c]	402,554
Calculated Grain Loading (gr/dscf @ 3% O_2) [d]	0.003
PM Loading Standard (IDAPA 58.01.01.677) (gr/dscf @ 3% 02)	0.015
Compliance w/ PM Loading Standard	**Yes**

[a] Appendix A-7 to 40 CFR part 60, Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates, Table 19-2 (F Factors for Various Fuels)

[b] Fd, Volumes of combustion components per unit of heat content (scf/million Btu). Fd for natural gas and biogas is 8,710 dscf/106 Btu

[c] $(Flow_{3\%}) = (Flow_{0\%}) \times (20.9/(20.9 - 3))$, where 20.9 = Oxygen concentration in ambient air

[d] (7,000 gr/lb) x (PM lb/hr) / (Flow (dscfm) x 60 (min/ hr)) = gr/dscf

Appendix D – Operation and Maintenance Manual

IDAHO POWER®
An IDACORP Company

Langley Gulch Power Plant

Emission Source Operations and Maintenance Manual

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

Overview

The Langley Gulch Power Plant is a power generation facility, comprised of a natural gas-fired combustion turbine (CT) and a steam-driven steam turbine (ST). The combustion turbine burns natural gas as a fuel source which drives a 4-stage axial turbine for generating electricity. The waste heat from the turbine is exhausted through a heat recovery steam generator (HRSG), where the heat from the flue gas is transferred to the boiler feedwater to produce steam. The steam is routed to the ST where it drives the turbine blades to generate additional electricity.

The auxiliary equipment onsite which supports the gas and steam turbine operations include a water treatment facility, a cooling tower, a diesel-fired firewater pump, a diesel-fired emergency generator, as well as a duct burner which is integrated into the HRSG.

Operating Requirements

Combustion Turbine

Control Equipment

- **Dry Low NOx Combustors:** The dry low NOx (DLN) combustors are an integral part of Siemens' combustion system. The combustors are permanently installed in the turbine and do not have the capability to be turned off. The combustors achieve low NOx emissions through a 4-stage fuel supply system. The stages have varying degrees of fuel/air mixing prior to combustion. This staging of the fuel allows the turbine to operate at a lean fuel-to-air mixture, which reduces the NOx emissions.
- **Selective Catalytic Reduction:** The selective catalytic reduction (SCR) is a system installed within the HRSG which reacts with the CT exhaust NOx emissions. The CT exhaust passes through the HRSG and when it reaches the SCR, vaporized ammonia (NH_3) is sprayed into the exhaust gas. The ammonia mixes with the exhaust and travels downstream into a catalyst grid. The ammonia/exhaust mixture reacts on the catalyst grid where the NOx and NH_3 react forming nitrogen gas (N_2) and water vapor (H_2O) which is exhausted through the stack.
- **Catalytic Oxidation:** The oxidation catalyst is a system installed within the HRSG which reacts with the CT exhaust carbon monoxide (CO) and volatile organic compounds (VOCs). The catalyst grid is located in the HRSG and when the exhaust gases pass through it, the CO molecules are oxidized and exhaust as carbon dioxide (CO_2) through the stack.
- **Good Combustion Practices:** The combustion turbine shall be operated in accordance with the recommended limits provided by the manufacturer. No control changes that will intentionally increase the emissions above the permitted levels shall be allowed. In addition, the CT and duct burners will be operated exclusively with pipeline quality natural gas.

Operational Procedures

- **CT BACT Emission Limits:** The combustion turbine shall be operated exclusively on natural gas, through the DLN combustion system. The DLN system shall be operated in accordance with the vendor's fuel fractioning schedules and recommendations. To meet the BACT emission levels, the CT exhaust gas shall pass through both the oxidation catalyst and the SCR during operations. These systems shall remain operable during normal operating conditions; however, during startup, shutdown, and low-load operations, these systems may have reduced effectiveness or may not be allowed to operate due to potential fouling/damage at low temperatures. During these conditions, the secondary BACT limits will be complied with.
- **Ammonia Flow:** The ammonia flow to the SCR shall be electronically archived at all times when the system is in service. The data shall be reduced to hourly averages to ensure the permit limit is not exceeded. A high flow alarm shall be programmed into the plant control system to alert the operations staff of abnormal conditions, in which case, action shall be taken to reduce the flow.
- **Control Equipment Maintenance & Operation:** The DLN combustion system will be inspected during each of the scheduled combustion turbine maintenance intervals. The oxidation catalyst and SCR will be inspected for fouling or physical damage no less than every two years. The CEMS and plant control system will be utilized to monitor for good combustion practices. Emissions above the permitted levels are indicative of either abnormal combustion practices or faulty equipment and will be investigated by the onsite operator. Any excess emissions will be reported in accordance with Permit Conditions 19-26.

<u>Emergency Diesel Generator</u>

Control Equipment

- **EPA Tier 2 Technologies:** The emergency engine was manufactured to the Tier 2 requirements and certified by the EPA under certificate #CPX-NRCI-10-03. Certificate available in generator O&M manual located in the plant control room.
- **Good Combustion Practices:** The emergency generator will be operated in accordance with the O&M manual distributed by the vendor. The engine shall be limited to 60 hrs/yr of operation for maintenance and readiness checks; operating no more than 4 hrs/day. Operation during emergency use is unlimited; however, excess emission evaluations may be required for operations in excess of permit limits. The engine will be operated exclusively on low sulfur diesel fuel. A non-resettable meter is installed on the engine and logs will be maintained of the operational hours.

Operational Procedures

- **Work Practices:** The emergency generator will be operated and maintained in accordance with prudent industry standards and applicable vendor instructions. No physical modifications which could increase emissions will be made to the engine without prior analysis.

Diesel Fire Pump

Control Equipment

- **EPA Tier 3 Technologies:** The diesel fire pump engine was manufactured to the Tier 3 requirements and certified by the EPA under the engine family #9CEXL0540AAB. Emission data sheet available in the fire pump O&M manual located in the plant control room.
- **Good Combustion Practices:** The diesel fire pump will be operated in accordance with the O&M manual distributed by the vendor. The engine shall be limited to 30 hrs/yr of operation for maintenance and readiness checks; operating no more than 1 hr/day. Operation during emergency use is unlimited; however, excess emission evaluations may be required for operations in excess of permit limits. The engine will be operated exclusively on low sulfur diesel fuel. A non-resettable hour meter is installed on the engine and logs will be maintained of the operational hours.

Operational Procedures

- **Work Practices:** The diesel fire pump will be operated and maintained in accordance with prudent industry standards and applicable vendor instructions. No physical modifications which could increase emissions will be made to the engine without prior analysis.

Cooling Tower

Control Equipment

- **Drift Eliminators:** The drift eliminators are installed above the water distribution sprayers and prevent water droplets from being carried airborne with the air passing through the fans. They are constructed of cellular PVC and force the air through direction changes which allow the entrained water droplets to coalesce on the surface and drop back into the tower basin.
- **Good Operating Practices:** The tower will be operated in accordance with prudent industry standards and applicable vendor instructions. The chemistry of the cooling tower will be maintained within the permitted levels.

Operational Procedures

- **Work Practices:** The drift eliminators are permanently installed in the cooling tower are in-service at all times the tower is operating. Along with maintaining the chemistry of the cooling water, the drift eliminators will be inspected for fouling and/or damage to ensure their effectiveness is not compromised.

Dry Chemical Storage Silos

Control Equipment

- **Bin Vent Filters:** The bin vent filters are installed on the roof of the storage silos. The vents have a filter installed which prevents the chemical from escaping into the atmosphere during loading operations. The bin vent filter is also equipped with an exhaust fan which pulls the air out of the silo and through the filter to maintain a vacuum within the silo. The fan pulls the air through the filter, which prevents air entrained with dry chemical from escaping through any other ports in the silo.
- **Good Operating Practices:** The storage silos will be operated in accordance with prudent industry standards and applicable vendor instructions. The bin vent filters will be operational during all loading operations.

Operational Procedures

- **Work Practices:** The bin vent filters will be installed and maintained in accordance with the written instructions included in the vendor's O&M manual. The filters and fan will be inspected and replaced as required.

Appendix E – Monitoring Plans & Protocols

LANGLEY GULCH POWER PLANT
NEW PLYMOUTH, IDAHO

CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) METHODOLOGY

PREPARED FOR: IDAHO POWER COMPANY

PREPARED BY: CUSTOM INSTRUMENTATION SERVICES CORPORATION

DATE: December 8, 2010
REVISION: 0

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1 INTRODUCTION

This document describes the Continuous Emissions Monitoring System (CEMS) being installed at the Langley Gulch Power Plant located near New Plymouth, Idaho. The CEMS includes oxide of nitrogen (NO_x), carbon monoxide (CO), and oxygen (O_2) analyzers on the combustion turbine exhaust stack. The CEMS instrumentation will be used to demonstrate continuous compliance with the allowable CO and NO_x limits set forth in the Idaho Department of Environmental Quality (IDEQ), Air Quality Permit to Construct (Permit Number P-2009.0092). The CEMS will also meet the monitoring and reporting requirements of the Acid Rain Program.

This document is designed to fulfill the requirement in Condition 52 the permit that the "permittee shall submit CEMS methodology and quality assurance and quality control protocols to DEQ for approval." A QA/QC Manual has been prepared and submitted under separate cover.

2 FACILITY DESCRIPTION

The Langley Gulch Power Plant is located near New Plymouth, Idaho. The site consists of a one-on-one combined-cycle plant, consisting of a natural gas-fired combustion turbine (CT) and a steam turbine. The CT is equipped with a heat recovery steam generator (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 increases steam production and steam turbine output for peak loads.

The unit is fired exclusively with pipeline quality natural gas and has an exhaust stack which discharges into the atmosphere approximately 160 feet above grade. The turbine has a maximum heat input of approximately 2134 mmBtu/hr at design conditions and generates 269 MW. The duct burner has a maximum heat input of approximately 241 mmBtu/hr at design conditions. The plant includes dry low NOx combustors and selective catalytic reduction (SCR) to control NOx emissions and a catalytic oxidation system to control CO emissions.

The NO_x and O_2 analyzers must meet the certification requirements of 40 CFR 75 and the CO analyzer must meet 40 CFR 60, Appendix B, Performance Specification 4/ 4A. As part of these requirements, CEMS certification testing will take place and a final test report will be submitted.

3 CEMS AND PROCESS MONITOR DESCRIPTION

Custom Instrumentation Services Corporation of Englewood, Colorado, manufactured the extractive CEM system being supplied to the Langley Gulch Power Plant. All analyses are performed on a "dry" basis from undiluted samples and hourly results are reported in ppm, ppm corrected to 15% O_2, lb/mmBtu and pounds per hour. Technical information on the system is provided in Appendix 1.

The CEMS will be used to determine compliance with emission limits listed in the permit, as follows.

TABLE 1
AIR QUALITY PERMIT TO CONSTRUCT EMISSION LIMITS

Pollutant	Normal Operation	Low-Load Operation	Startup and Shutdown	Annual Emissions	Applicable Regulation
NO_x ppm @ 15% O_2, 3-hour rolling average	2.0	96	96	NA	PTC Section 33, 34, 35
NOx ppm @ 15% O_2, 30-day rolling average	15	96	NA	NA	PTC Section 37
NO_x Tons/Year	NA	NA	NA	88	PTC Section 36
CO ppm @ 15% O_2, 3-hour rolling average	2.0	24.5	NA	NA	PTC Section 33, 34
CO lb/hr	NA	NA	2510	NA	PTC Section 35
CO Tons/Year	NA	NA	NA	278.1	PTC Section 36
VOC ppm @ 15% O_2, 3-hour rolling average	2.0	11.5	NA	NA	PTC Section 33, 34

3.1 Analyzers

Oxides of Nitrogen (NO_X):

For the analysis of NO_x, a Teledyne (TAPI) Model 200EM analyzer is used. The Chemiluminescence detection method quantitatively converts NO to NO_2 by gas-phase oxidation with molecular ozone that is produced by the analyzer ozone generator in an environment, of system supplied dry instrument air. The Model 200EM converts NO_2 to NO by employing a converter cartridge filled with molybdenum (Mo, "moly") chips heated to a temperature of 600° F. The analyzer ranges are 10 ppm and 150 ppm and the analyzer will be calibrated daily on both ranges with cylinders of NO gas at approximately 9 and 135 ppm.

Carbon Monoxide Analyzer:

For the analysis of CO, a Teledyne (TAPI) Model 300EM analyzer is used. The Model 300EM Gas Filter Correlation Carbon Monoxide analyzer is a microprocessor-controlled analyzer that determines the concentration of carbon monoxide (CO) in a sample gas drawn through the instrument. It requires that sample and calibration gasses be supplied at ambient atmospheric pressure in order to establish a stable gas flow through the sample chamber where the gases ability to absorb infrared radiation is measured. The analyzer ranges are 10, 50 and 3000 ppm. The analyzer will be calibrated daily with cylinders of CO gas at approximately 8, 40 and 2400 ppm.

Oxygen Analyzer:

For the analysis of Oxygen, the O_2 channel of the Teledyne (TAPI) Model 200 EM analyzer is used. This type of analyzer is characteristically linear and is not sensitive to interference from moisture, combustibles, or physical vibrations. A true gross oxygen analysis is provided. The 0-

25% full-scale range will be configured into the system to allow for a span check daily with instrument air (20.9% O_2).

3.2 DATA ACQUISITION AND HANDLING SYSTEM DESCRIPTION

The Data Acquisition and Handling System (DAHS) provides historical data storage with review and complete editability. It generates all required reports in the format which is acceptable to IDEQ; hourly, daily, monthly summaries, and quarterly exceedance reports generated automatically or on demand. The electronic quarterly report required by EPA for 40 CFR 75 will be generated for submittal within 30 days after the end of the previous quarter. The DAHS is a passive system, receiving the majority of its information (data and control) from the CEM system. To acquire the balance of its information (i.e., fuel flow) interface is provided to the plant control systems.

Software provided for data acquisition is an integrated, user-friendly, menu-driven software package developed by CiSCO for data acquisition, analysis and reporting. Data acquisition will continue uninterrupted in the background while data manipulation and report generation is taking place in the foreground. The calculation of emissions in units of the applicable standards (ppm @ 15% O_2, lb/hr, lb/mmBtu) is accomplished by the DAHS. The calculations used are provided in Appendix 2.

3.3 Sample Handling

All components necessary to acquire a representative sample, condition that sample without loss of sample integrity and supply that sample to the analyzer for analysis are included in the system. All sample-wetted surfaces are Teflon, stainless steel or glass.

Sample Acquisition: A representative sample of gas from the stack is acquired with a CiSCO sample probe and is transported to the shelters via heated sample lines. The sample probes are designed to mount on a four-inch (4"), 150 pound ANSI flange. The probe assembly includes a 316L SS filter chamber located outside the flange in a NEMA 4 enclosure. This allows the filter to be periodically maintained safely without removing the probe from the gas stream. It also eliminates pluggage of the filter by direct impact of particulate or water droplets on the filter. The filter is rated at 15 microns and can be easily replaced or cleaned.

The heated sample line keeps the sample gas temperature above its acid dewpoint during transport to the shelter. A 5/16" OD stainless steel tube is traced with an electrical heater insulated with 1/2" of insulation and covered with a scuff-resistant jacket. The temperature-controlled heater is designed to maintain the sample temperature above 350°F. The probe and heated sample line are capable of accommodating flue gas with temperatures in excess of 400°F.

Sample Conditioning: The sample is conditioned by filtering out the particulate, and removing the sample gas moisture. Two stages of filtration are used; the coarse filter located in the sample probe will protect the heated sample line from plugging and a secondary fine filter located in the shelter will remove 99.99% of all particulate 0.1 micron and larger in size. This filter is located downstream of the refrigeration-cooled sample dryer. The clear shell of the filter housing simplifies visual inspection of the filter exterior conditions.

Drying of the sample is accomplished in two stages. First, the sample is passed through a refrigeration-cooled cold-water bath where the sample temperature and therefore its dewpoint, is lowered to approximately 35°F. All condensable moisture is separated from the sample gas and is continuously removed from the system with a peristaltic pump. To reduce the interference due to moisture and to prevent acid mist carryover, the sample dewpoint is lowered further with a membrane dryer. The remaining sample gas moisture permeates the membrane in the gaseous phase and is carried away in the ultra-dry purge air. The system includes a dual-column, regenerative air dryer to provide purge air to the membrane dryer at a nominal -80°F dewpoint. An effective sample dewpoint of 0°F to -20°F is obtained.

Sample Transport: The sample is drawn into the shelter with a Teflon-coated, Teflon diaphragm pump. A backpressure regulator on the output of the sample pump acts as a variable pressure relief valve, providing a sample bypass, which is vented. Adjustment of this bypass flow allows adjustment of the overall system response time. Fluctuations in process pressure and flow conditions are passed out of this bypass, rather than through the system, and therefore do not affect the analyzer. Pressure regulators with pressure gauges and flow control valves with flowmeters are used to set and regulate the pressure and flow of sample gas to each analyzer. These devices assure that calibration gas and sample gas is supplied to the analyzer at the same flow and pressure for an accurate analysis.

3.4 CEMS Calibration

The CEMS is equipped with the capability to initiate the automatic calibration routing on demand, and to call in the calibration solenoid valves to a completely manual calibration for maintenance. The automatic calibration routine will be performed every 24 hours on each of the analyzers under the programmed control system (PLC). The analyzers are zeroed on nitrogen, supplied from a high-pressure gas cylinder. The calibration span gases are also supplied from high-pressure gas cylinders.

In the manual calibration mode, calibration gas can either be injected directly into the analyzer for a diagnostic check only or injected into the sample probe via a 1/4" Teflon line in the probe support bundle, so that calibration gas flows through the entire sample handling system to verify the integrity of the total system. In the automatic calibration mode, calibration gas is injected into the sample probe on a daily basis.

CEMS Calibration Fail Alarms: To facilitate meeting applicable Federal and State regulations, the actual response of the analyzer during calibration is compared with a known absolute required response. If the error is larger than regulations allow, calibration fail alarms are activated, signaling a maintenance requirement and a readjustment of the analyzer.

CEMS Calibration Span & Zero Correction: If a calibration is conducted successfully, the PLC program calculates the amount of error in the readings, (zero and span) for the analyzer and generates a correction factor that corrects the slope and zero of the analyzer's response. This correction factor is applied to all subsequent sample readings to adjust the results to a "perfect" calibration.

3.5 *SAMPLE LOCATION*

The sample port for the CEMS sample probe is approximately 53 feet, 4 inches (2.9 diameters) from a downstream disturbance and is approximately 11 feet (0.6 diameters) upstream of the stack exhaust. The sample probe is 5 feet long, which will make the sample location at a representative point in the 18 foot, 7 inch diameter stack. Four EPA ports are located 6 inches above the CEMS ports. A sketch of the sampling locations is presented in Figure 1. The CEMS is housed in a ten by ten (10' x 10') metal shelter, located at the base of the stack. The shelter is climate controlled and provides a clean environment for the analyzers and associated equipment.

4 CERTIFICATION STRATEGY

The certification testing for the Langley Gulch Power Plant must meet the requirements of 40 CFR 60 and 40 CFR 75. To the extent possible, testing will be completed to meet all requirements concurrently. The performance specifications are presented in Table 1.

40 CFR 75: Testing to meet 40 CFR 75 requirements will be performed on the NO_x, and O_2 analyzers. The testing consists of a 7-day drift test, RATA, linearity and cycle response time. The results from the RATA testing will be presented in lb/mmBtu. The linearity test consists of three runs using three levels of calibration gas. The cycle response time test determines the upscale and downscale response of both the NO_x and O_2 analyzers.

40 CFR 60: The CO analyzer will be tested to meet the requirements of 40 CFR 60, Appendix B, Performance Specification 4/4A. The tests include a 7-day drift test, a response time test and a Relative Accuracy Test Audit (RATA). Calculations will be done for ppm @ 15% O_2 and lb/hr. All testing will be performed while the plant is operating at a minimum of 50 percent of normal load.

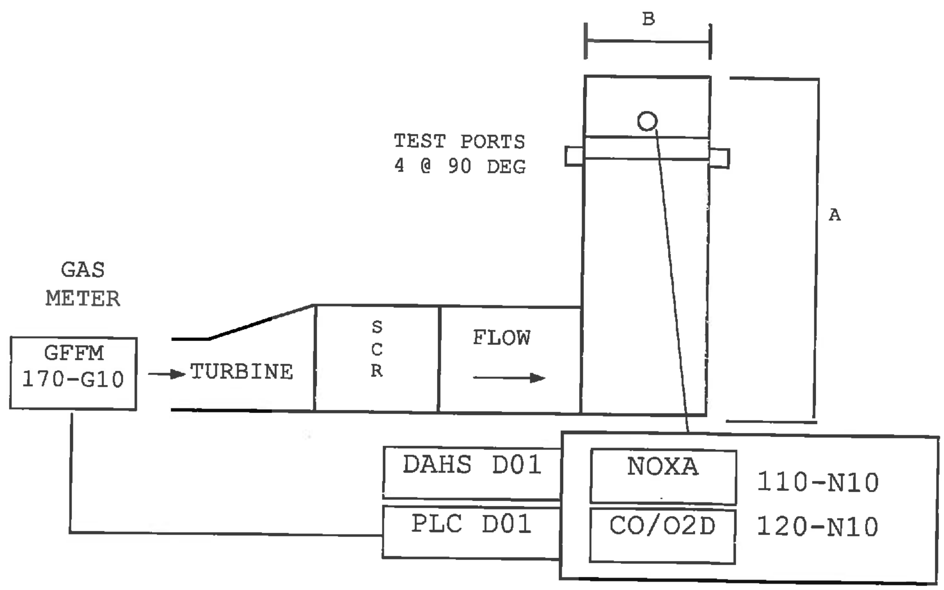
For both regulations, the RATA will involve verification by a third party test team, following 40 CFR 60, Appendix A test methods. Nine to twelve test runs will be performed. During these tests, the sample location will be tested for stratification. To perform the test, the DAHS will be placed in an "Audit Mode" and values will be recorded every minute and then averaged for the duration of the test period. These values are compared to the test team's values for the same test period. The difference between the two sets of values must meet the requirements listed in Table 2.

TABLE 2: CEMS PERFORMANCE SPECIFICATIONS

	40 CFR 60	40 CFR 75
24-hr Drift – Zero and Span NO_x O_2 CO	• NA • NA • 5% of range of analyzer	2.5% of span of analyzer or 5 ppm 0.5% O_2 NA
RESPONSE TIME TEST CO	• 1.5 minutes	NA
CYCLE RESPONSE TEST NO_x O_2	• NA • NA	15 minutes 15 minutes
LINEARITY NO_x O_2	• NA • NA	5% of gas value or 5 ppm 5% O_2
RATA NO_x lb/mmBtu O_2 % CO ppm @ 15% O_2 and lb/hr	• NA • NA • 10% RA, 5% of std, 5 ppm	7.5% RA or $\pm$0.015 lb/mmBtu [1] NA NA
DAHS ACCURACY	Verify formulas	Verify formulas

1. Accuracy for annual Relative Accuracy (RA) frequency

FIGURE 1: CEMS SAMPLE PORT LOCATIONS



Monitor Location Information

A. Stack Height Above Grade - 160 feet
B. Stack Inside Diameter at Test Port - 18 feet, 7 inches
C. Inside Cross Sectional Area at CEMS Location 271.2 feet^2
D. CEMS Probe Elevation
   1. Above Grade 149 feet, 0 inches
   2. Above Last Disturbance
      a. Feet 53 feet, 4 inches
      b. Stack Diameters 2.9
   3. Prior to Stack Exit
      a. Feet 11 feet, 0 inches
      b. Stack Diameters 0.6

5 QUALITY ASSURANCE REQUIREMENTS

The CEMS for the Langley Gulch Power Plant is designed to meet the reporting, record keeping, certification, and quality assurance requirements of the requirements of 40 CFR 75, 40 CFR 60 and the IDEQ permit.

5.1 DATA VALIDATION REQUIREMENTS

Personnel at the Langley Gulch Power Plant strive to achieve 95% availability of the monitors under normal operating conditions. All reasonable and practical means are used to achieve this objective, including overtime corrective maintenance work, quarterly audits, routine preventative maintenance, and daily calibration checks. All pertinent regulations require the reduction of emissions to one-hour time-based emissions.

5.1.1 Invalid Data

Numerous conditions can render data invalid. If the correct numbers of valid data points are not collected for any reason, then the data collected is considered invalid. For 40 CFR 75 reporting, invalid data is automatically replaced by the DAHS. For 40 CFR 60 reporting, invalid data is reported as monitor downtime. The following are examples of conditions, which could result in invalid data:

- CEMS control power failure
- Analyzer malfunction
- Water in sample
- Back-flush cycle
- Last calibration fail (40 CFR 75) or out-of-control (for 40 CFR 60)
- Out-of-Service
- CEMS Off-line
- CEMS failed linearity test (out-of-control)
- CEMS failed relative accuracy (out-of-control)

5.1.2 Data Averaging

a) The CEMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period. This is defined as a data point.

b) A valid hour of data is computed from four or more data points equally spaced over the one-hour period. Gaseous emissions data are reduced and recorded as one-hour averages. If one of the 15-minute periods (using four data points per hour) is invalid, the hour is considered invalid and the DAHS will replace the hourly data using the missing data procedures in 40 CFR 75 or will report the period as monitor downtime.

c) For 40 CFR 75 reporting, during periods of calibration, quality assurance or maintenance activities, a valid hour consists of at least two data points separated by a minimum of 15 minutes. If the CEMS does not collect valid data in accordance with this criteria, then the missing data procedures must be used to replace the data. In order to perform calibrations, quality assurance or maintenance, the "out-of-service" periods should begin more than 30 minutes into an hour and end less than 30 minutes into the next hour. In this way, nearly 60 minutes of service can be performed on the system without impacting availability.

d) For quarterly 40 CFR 75 reporting, all missing or invalid data is automatically replaced by the DAHS following the procedures contained in 40 CFR 75, Subpart D (for NO_x) and Appendix D (for fuel flow).

e) After determination of the emissions in the proper reporting parameters, the emissions data is rounded off to the same number of significant digits as the emission limit or the number of significant digits required by EPA.

5.2 CEMS GAS ANALYZER CALIBRATION

The CEMS is equipped with manual and automatic, zero and span calibration capabilities. The automatic calibration routine is performed every 24 hours on each of the analyzers under the programmed control of the system PLC. In addition, a calibration can be started manually at any time with the activation of the "Cal Start" button on the Operator Interface Terminal (OIT).

In either mode, a "Cal-at-Cabinet" valve allows the operator to select one of two modes of calibration. With the valve in the cabinet position, calibration gas is injected directly into the sample flow control components and then into the analyzers. With the valve in the probe position, calibration gas is injected into the sample probe via the 1/4" Teflon calibration line in the probe support bundle. The calibration gas is then pulled through the sample conditioning subsystem just as the sample is, and the integrity of the entire system is checked. This is the normal mode, which is used during the automatic calibration routine.

In the automatic calibration sequence, either manually or automatically initiated, the cal gas solenoid valves are automatically sequenced by the system PLC. The first four minutes of each five-minute period of gas flow is used for system stabilization. During the last minute, the analyzer response is interrogated by the PLC. Eleven values are read, five seconds apart, and are averaged for an average calibration reading. Initial programming has timed the calibration sequence, five minutes for zero and five minutes for each analyzer span.

If the calibration check passes, a new sample output correction factor is calculated for each analyzer and is stored to be used during sampling until the next calibration. If the calibration fails, the calibration fail alarm is activated and the subsequent sample output signal(s) will be uncorrected for each failed analyzer. Programming for 40 CFR 75 allows a maximum ±1% difference from reference gas for O_2 and ±5% of span for NO_x. Programming for the operating permit and 40 CFR 60 allows a maximum ±20% of range for CO out-of-control.

In order for the PLC to check the validity of a calibration and generate a fail or out-of-control signal if the analyzer response is outside of preset limits, it not only needs to know the actual analyzer response, it also must "know" a constant to compare it with. For zero, the constant is zero, and is stored in a register in the PLC. All analyzer span concentration values are input to the PLC via the OIT. These inputs are taken directly from the span gas cylinder labels.

The zero calibration gas should be zero grade nitrogen (N_2) as supplied by a specialty gas supplier. The nominal span gas concentrations required for the Langley Gulch Power Plant project are provided in Table 3.

TABLE 3: ANALYZER RANGES AND NOMINAL SPAN GAS CONCENTRATIONS

ANALYZER	FULL SCALE RANGES	40 CFR 75 SPAN	NOMINAL SPAN GAS
NO_x	0-10 and 0-150 ppm	0-10 and 0-150 ppm	9 and 135 ppm
CO	0-10, 0-50 and 0-3000 ppm	NA	8, 40 and 2400 ppm
O_2	0-25 %	0-21 ppm	20.9% (Inst. Air)

Calibration adjustment procedures for gas analyzers are provided in Appendix 2. The specific analyzer manufacturer's manuals are contained in the CEMS O&M Manual, which is incorporated here by reference.

APPENDIX 1

TECHNICAL INFORMATION

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company

MODEL 200EH / 200EM

Chemiluminescene High & Medium Range $NO/NO_2/NO_X$ Analyzers

- 200EH: 0-5 ppm to 0-5000 ppm, user selectable
- 200EM: 0-1 to 0-200 ppm, user selectable
- Independent ranges for NO, NO_2, NO_X
- Auto ranging and remote range selection
- Microprocessor controlled for versatility
- NO_X-only or NO-only modes
- Multi-tasking software allows viewing of test variables while operating
- Continuous self checking with alarms
- Permeation drier on ozone generator
- Dual bi-directional RS-232 ports for remote operation (optional Ethernet or RS-485)
- Digital status outputs provide instrument condition
- Adaptive signal filtering optimizes response time
- Temperature & pressure compensation, automatic zero correction
- Converter efficiency correction software
- Minimum CO_2 and H_2O interference
- Catalytic ozone scrubber
- Internal data logging with 1 min to 365 day multiple averages (1 million records)

The Models 200EH and 200EM use the proven chemiluminescence measurement principle, coupled with state-of-the-art microprocessor technology for monitoring high and medium levels of nitrogen oxides. User-selectable analog output ranges and a linear response over the entire measurement range make them ideal for a wide variety of applications, including extractive and dilution CEM, stack testing, and process control.

A choice of NO_2 converters handles tough CEM and stack testing as well as combustion turbine startup and continuous operation applications. Selectable measurement modes (NO_X only, NO only, NO/NO_X switching), auto ranging (single range, dual range, auto-range, independent ranges, remote range control) enables to match the Models 200EH or 200EM to your needs. Modular instrument design offers top-mounted, quick access to all subassemblies and hinged front and rear panels to simplify module replacement and maintenance. A standard permeation dryer on the ozone generator provides dry air and excess ozone is removed by catalytic reaction, both eliminating the need for expendables.

All instruments in the Teledyne-API Model "E"-Series include built-in data acquisition capability with internal memory. This allows logging of multiple parameters in different pre-defined or customized data channels including averaged or instantaneous concentration values, calibration data, and operating parameters such as pressures and flow rates. Stored data are easily retrieved through the RS-232 port via APICOM or from the front panel, allowing predictive diagnostics and enhanced data analysis by tracking parameter trends.

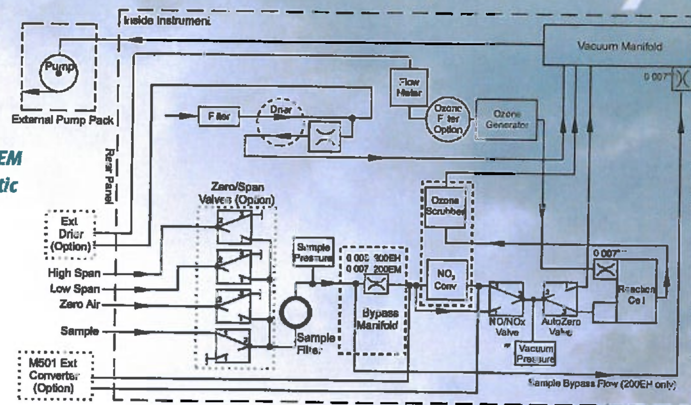
The Models 200EH and 200EM combine rugged construction, light weight, ease of use, powerful diagnostics and outstanding performance for high and medium range applications.

Approved - Returned: 12/14/2010

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company

MODEL 200EH / 200EM

Chemiluminescence High & Medium Range NO/NO_2/NO_x Analyzer



Model 200EH/EM schematic

SPECIFICATIONS

Ranges:	**200EH:** 0-5 ppm to 0-5000 ppm full scale, user selectable; independent NO, NO_2, NO_X ranges and auto-ranging supported **200EM:** 0-1 ppm to 0-200 ppm
Units:	ppm, mg/m³
Zero Noise:	<20 ppb (RMS)
Span Noise:	<0.2% of reading above 20 ppm (RMS)
Lower Detectable Limit (LDL):	<40 ppb (RMS)
Zero Drift:	<20 ppb/24 hours
Span Drift:	<1% reading/24 hours, <1% reading/7 days
Lag Time:	20 seconds switching mode; <6 seconds NO or NO_X only mode
Rise and Fall Time:	<60 seconds to 95% (switching); 5 seconds NO only; 10 seconds NO_X only
Linearity:	1% full scale
Precision:	0.5% of reading
Sample Flow Rate:	250 cm³/min (standard); 500 cm³/min (optional)
Operating Temperature Range:	5 - 40°C

Dimensions (HxWxD):	7" (178 mm) x 17" (432 mm) x 23.5" (597 mm)
Weight:	Analyzer 44 lbs (20 kg), External Pump 15 lbs (7 kg)
Power:	100V 50/60 Hz, 115V 60Hz, 220V 50/60Hz, 230V 50Hz, 240V 50Hz 250 Watts (analyzer), 250 Watts (pump)
Analog Outputs:	10V, 5V, 1V, 0.1V, selectable
Recorder Offset:	±10%
Serial Outputs:	Serial Port 1: RS-232, DB-9M Serial Port 2: standard RS-232 or optional RS-485, DB-9F
Status (Digital)	8 outputs, 6 inputs (opto-isolated), 6 alarm outputs (optional)
Current Output:	0-20 mA or 4-20 mA isolated outputs (optional)
Approvals:	CE

HOW TO ORDER

Model 200EH/EM Chemiluminescence NO/NO_2/NO_X Analyzer Includes:

- External pump
- Permeation ozone air dryer
- Independent NO, NO_2, NO_X ranges
- Auto ranging
- 47 mm particulate filter
- 12 isolated digital status outputs
- Dual bi-directional RS-232
- APICOM remote control software

Specify voltage/frequency:

- ☐ 100V/50Hz
- ☐ 220V/50Hz
- ☐ 230V/50Hz
- ☐ 240V/50Hz
- ☐ 100V/60Hz
- ☐ 115V/60Hz
- ☐ 220V/60Hz

Specify output voltage:

☐ 10V ☐ 5V ☐ 1V ☐ 0.1V

Additional Options:

- ☐ Rack mount brackets (19") with chassis slides
- ☐ Rack mount brackets only
- ☐ Isolated 0-20 mA or 4-20 mA Output (specify up to 3 channels)
- ☐ Multi-drop serial interface
- ☐ Ethernet port includes 7 ft. CAT-5 cable (disables one serial port)
- ☐ Permeation dryer for sample gas
- ☐ Ozone air filter assembly

Calibration Valves:

- ☐ Dual-valve assembly for selection of customer-supplied zero and span gas (two gases)
- ☐ Triple-valve assembly for selection of customer-supplied zero and span gases (three gases or two gases and pressure vent)

NO_2 Converters:

- ☐ Mini-HICON Internal Converter (standard on 200EH)
- ☐ MOLYCON Converter (standard on 200EM)
- ☐ MODEL 501 External Converter (optional)

Accessories:

- ☐ RS-232 Cable
- ☐ Expendables Kit
- ☐ Spare Parts Kit
- ☐ Chassis carrying handle
- ☐ Zero Air Scrubber

For more information on Teledyne API's family of monitoring instrumentation products, call us or visit our website at **www.teledyne-api.com**

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TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company

MODEL **300E**

Gas Filter Correlation CO Analyzer

EPA APPROVAL RFCA-1093-093
MCERTS certified Sira MC050069/00

The Model 300E measures low ranges of carbon monoxide by comparing infrared energy absorbed by a sample to that absorbed by a reference gas according to the Beer-Lambert law. This is accomplished with a Gas Filter wheel which alternately allows a high energy light source to pass through a CO filled chamber and a chamber with no CO present. The light path then travels through the sample cell, which has a folded path of 14 meters.

The energy loss through the sample cell is compared with the span reference signal provided by the gas filter to produce a signal proportional to concentration, with little effect from interfering gases within the sample. This design produces excellent zero and span stability and a high signal to noise ratio allowing extreme sensitivity.

Multi-tasking software gives real time indication of numerous operating parameters and provides automatic alarms if diagnostic limits are exceeded. Built-in data acquisition and internal memory allows logging multiple parameters including average and instantaneous values, calibration data and operating parameters. Stored data are easily retrieved through the serial port or optional Ethernet port via our APIcom software or from the front panel, allowing operators to perform predictive diagnostics and enhanced data analysis by tracking parameter trends.

The Model 300E features rugged construction and is designed to perform with a minimum of attention. In the event maintenance is required, modular construction makes service a simple operation.

- **Ranges, 0-1 ppm to 0-1000 ppm, user selectable**
- **Gas Filter Wheel for CO specific measurement**
- **14 meter path length for sensitivity**
- **Microprocessor controlled for versatility**
- **Multi-tasking software allows viewing of test variables during operation**
- **Continuous self checking with alarms**
- **Bi-directional RS-232 for remote operation**
- **Digital status outputs indicate instrument operating condition**
- **Adaptive signal filtering optimizes response time**
- **GFC wheel guaranteed against leaks for 5 years**
- **Temperature & Pressure compensation**
- **Internal data logging with 1 min to 365 day multiple averages**
- **APIcom remote operation software**

Approved - Returned: 12/14/2010

190-RE-0005-001 - Packet 190-014 - Langley Gulch Power Plant - 2008044 - Received: 12/10/2010

MODEL **300E**

Gas Filter Correlation CO Analyzer

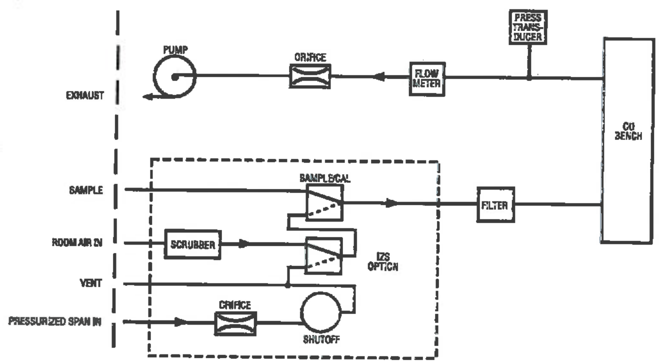
Specifications

Ranges:	0-1 ppm to 0-1,000 ppm full scale, user selectable. Dual ranges and auto ranging supported
Units:	ppb, ppm, µg/m³, mg/m³
Zero Noise:	<0.02 ppm
Span Noise:	<0.5% of reading above 5 ppm (RMS)
Lower Detectable Limit (LDL):	0.04 ppm
Zero Drift:	<0.1 ppm/24 hours, 0.2 ppm/7 days
Span Drift:	<0.5% of reading/24 hours, 1% of reading/7 days
Lag Time:	10 seconds
Rise and Fall Time:	<60 seconds to 95%
Linearity:	1% of full scale
Precision:	0.5% of reading
Sample Flow Rate:	800 cm³/min ±10%
Operating Temperature Range:	5 - 40°C (with EPA Equivalency)

Dimensions (HxWxD):	7" (178 mm) x 17" (432 mm) x 23.5" (597 mm)
Weight:	40 lbs
Power:	100V - 120V, 220V - 240V, 50/60 Hz, 250W
Analog Outputs:	10V, 5V, 1V, 0.1V, selectable
Recorder Offset:	±10%
Serial Outputs:	Serial Port 1: RS-232 (DB-9M) Serial Port 2: standard RS-232 or optional RS-485 (DB-9F), Ethernet
Status (Digital)	8 outputs, 6 inputs (opto-isolated), 4 alarm outputs (optional)
Current Output:	Optional 4-20mA, select up to three channels
Approvals:	USEPA RFCA-1093-093, MCERTS certified Sira MC050069/00

NOTE: The values expressed above are in accordance with EPA definitions. All error specifications are based on constant conditions. Specifications exceed US EPA and Eignungsgeprüft requirements.

Schematic



How to Order

Model 300E Gas Filter Correlation CO Analyzer includes:

- Internal pump
- Auto ranging and dual ranges
- 47mm diameter particulate filter
- 8 isolated digital status outputs
- 6 isolated digital inputs
- Bi-directional RS-232
- APIcom remote control software

Specify input AC voltage & frequency:

☐ 100V - 115V ☐ 50Hz
☐ 220V - 240V ☐ 60Hz

Specify output DC voltage:

☐ 10V ☐ 5V ☐ 1V ☐ 0.1V

Calibration Options:

☐ TFE valves for selection of customer-supplied zero and span gas
☐ Internal zero air scrubber

Additional Options:

☐ Rack mount brackets (19") with chassis slides
☐ Rack mount brackets only
☐ 4-20mA outputs (specify up to three channels)
☐ Multi-drop RS-232 connection
☐ RS-485 communications
☐ Ethernet

Calibration Valves:

☐ Stainless steel valves for selection of customer-supplied zero and span gas
☐ Shut-off valve and flow control for external span gas cylinder
☐ Internal zero air scrubber

Accessories:

☐ RS-232 Cable
☐ Expendables Kit
☐ Spare Parts Kit

Specifications subject to change without notice. M300E/01.06

TELEDYNE INSTRUMENTS
Advanced Pollution Instrumentation
A Teledyne Technologies Company
9480 Carroll Park Drive ■ San Diego, CA 92121-5201
Ph. 858-657-9800 Fax 858-657-9816
Email api-sales@teledyne.com

For more information about the Teledyne API family of monitoring instrumentation products, call us or visit our website at

www.teledyne-api.com

CERTIFIED QUALITY ISO 9001:2000 MANAGEMENT SYSTEM DNV

Approved - Returned: 12/14/2010

190-RE-0005-001 - Packet 190-014 - Langley Gulch Power Plant - 2008044 - Received: 12/10/2010

2. SPECIFICATIONS, APPROVALS AND WARRANTY

2.1. SPECIFICATIONS

Table 2-1: Model 300E/300EM Basic Unit Specifications

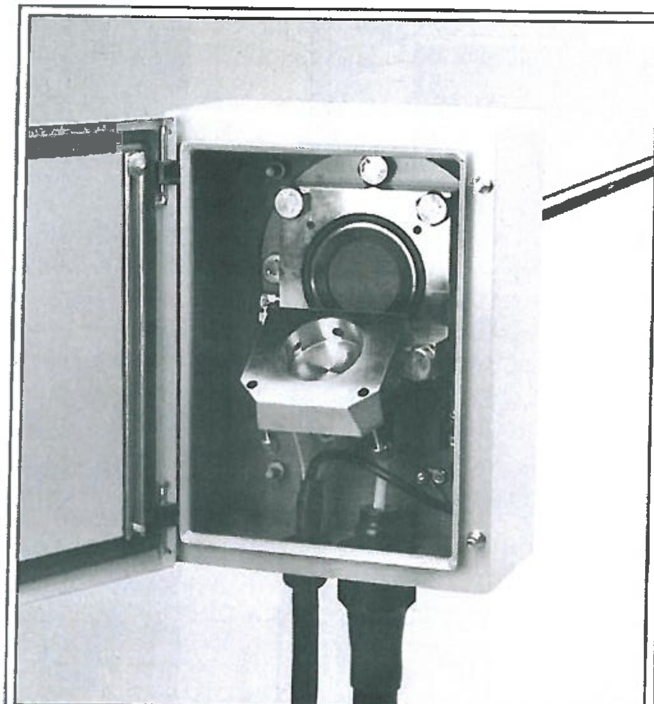
Ranges	M300E: Min: 0 1ppm; Max: 0 1000 ppm (User selectable) M300EM: Min: 0 1 ppm; Max: 0 5000 ppm (User selectable)	
Measurement Units	M300E: ppb, ppm, µg/m³, mg/m³ (user selectable) M300EM: ppm, mg/m³ (user selectable)	
Zero Noise	M300E: ≤ 0.02 ppm RMS[1];	M300EM: ≤ 0.1 ppm RMS[1]
Span Noise	M300E:<0.5% of rdg RMS over 5ppm[1, 3];	M300EM:>0.5% of rdg RMS over 20ppm
Lower Detectable Limit	M300E: < 0.04 ppm[1];	M300EM: 0.2 ppm
Zero Drift (24 hours)	M300E: < 0.1 ppm[2];	M300EM: <0.5 ppm
Zero Drift (7 days)	M300E: < 0.2 ppm[2];	M300EM: <1.0ppm
Span Drift (24 hours)	< 0.5% of reading[2,4]	
Span Drift (7 days)	< 1% of reading[2, 4]	
Linearity	M300E: Better than 1% full scale[5]; M300EM: 0 3000 ppm: 1% full scale;	3000 5000 ppm: 2% full scale
Precision	0.5% reading[1,5]	
Lag Time	<10 sec[1]	
Rise/Fall Time	<60 sec to **95%**[1]	
Sample Flow Rate	800cm³/min. ±10% O_2 Sensor option adds 120 cm³/min to total flow though when installed;	
Temperature Range	5 40 C operating, 10 40 C EPA Equivalency	
Humidity Range	0 95% RH, Non Condensing	
Temp Coefficient	< 0.05 % per C (minimum 50 ppb/ C)	
Voltage Coefficient	< 0.05 % per V	
Dimensions (HxWxD)	7" x 17" x 23.5" (178 mm x 432 mm x 597 mm)	
Weight	50 b (22.7 kg)	
AC Power	100V 50/60 Hz (3.25A), 115 V 60 Hz (3.0A), 220 240 V 50/60 Hz (2.5A)	
Environmental Conditions	Installation Category (Over voltage Category) II Pollution Degree 2	
Analog Outputs	4 user configurable outputs	
Analog Output Ranges	All Outputs: 0.1 V, 1 V, 5 V or 10 V Three outputs convertible to 4 20 mA isolated current loop. All Ranges with 5% under/over range	
Analog Output Resolution	1 part in 4096 of selected full scale voltage	
Status Outputs	8 Status outputs from opto isolators	
Control Inputs	6 Control Inputs, 2 defined, 4 spare	
Serial I/O	One (1) RS 232; One (1) RS 485 (2 connecters in parallel) Baud Rate : 300 115200	
Alarm outputs (M300EM only)	2 opto-isolated alarms outputs with user settable alarm limits	
Certifications	USEPA: Reference Method Number EQOA 0992 087 CE: EN61010 1:90 + A1:92 + A2:95, EN61326 Class A	

[1] As defined by the USEPA
[2] At constant temperature and voltage
[3] Or 0.2 ppm, whichever is greater
[4] Or 0.1 ppm, whichever is greater
[5] Above 10 ppm range, otherwise 0.2 ppm for lower ranges

CiSCO

CUSTOM INSTRUMENTATION SERVICES CORPORATION

Stack Gas Sample Probe - Model EP750



Features

- Time-tested, field-proven design with backflush
- Cal gas injection on inlet side of filter
- A simple, easily maintained probe with no welded parts
- Can be built in any machinable material, typically 316L stainless steel or Hastelloy C-276
- Insertion tube can be any length and can be field shortened; it threads into body and is easily replaced
- Designed to mount on 4 inch 150 pound ANSI flange
- Heated filter chamber located outside of flange allows safe, easy filter change
- Electrical heater standard, or optional steam heater suitable for Class 1 Division 2 installation
- Filtration 5 to 25 microns with reusable non-reactive filters
- No active components at sample probe location
- No plant utilities required at sample probe location; sample probe completely supported from analysis enclosure
- High temperature model also available

Design Description

The CiSCO sample probe is designed to mount on a 4 inch 150 pound ANSI flange. It can be fabricated out of any machinable material. The probe is also available in a high temperature configuration and an explosion proof model. The probe assembly includes a heated filter chamber, located outside the flange in a NEMA 4 enclosure, which allows the filter to be periodically maintained safely without removing the probe from the gas stream. This eliminates filter clogging due to the direct impact of particulate or water droplets. The heater prevents the sample temperature from cooling to inhibit condensation of the sample gas moisture.

Filter easily cleaned or replaced

The filter, which is application-specific, is rated at 5 to 25 microns and can be easily replaced or cleaned. It is safely accessed via a hinged assembly, secured with two captive screws. Separate gas connections for sample extraction and backflush are incorporated into the filter chamber design. The calibration gas is injected on the stack side of the filter.

Simple maintenance

The insertion tube, which penetrates the stack, is easily maintained. If an obstruction occurs, the straight through design of the tube allows the blockage to be cleared with a ramrod without removing the probe from the gas stream.

Utilities not required at probe location

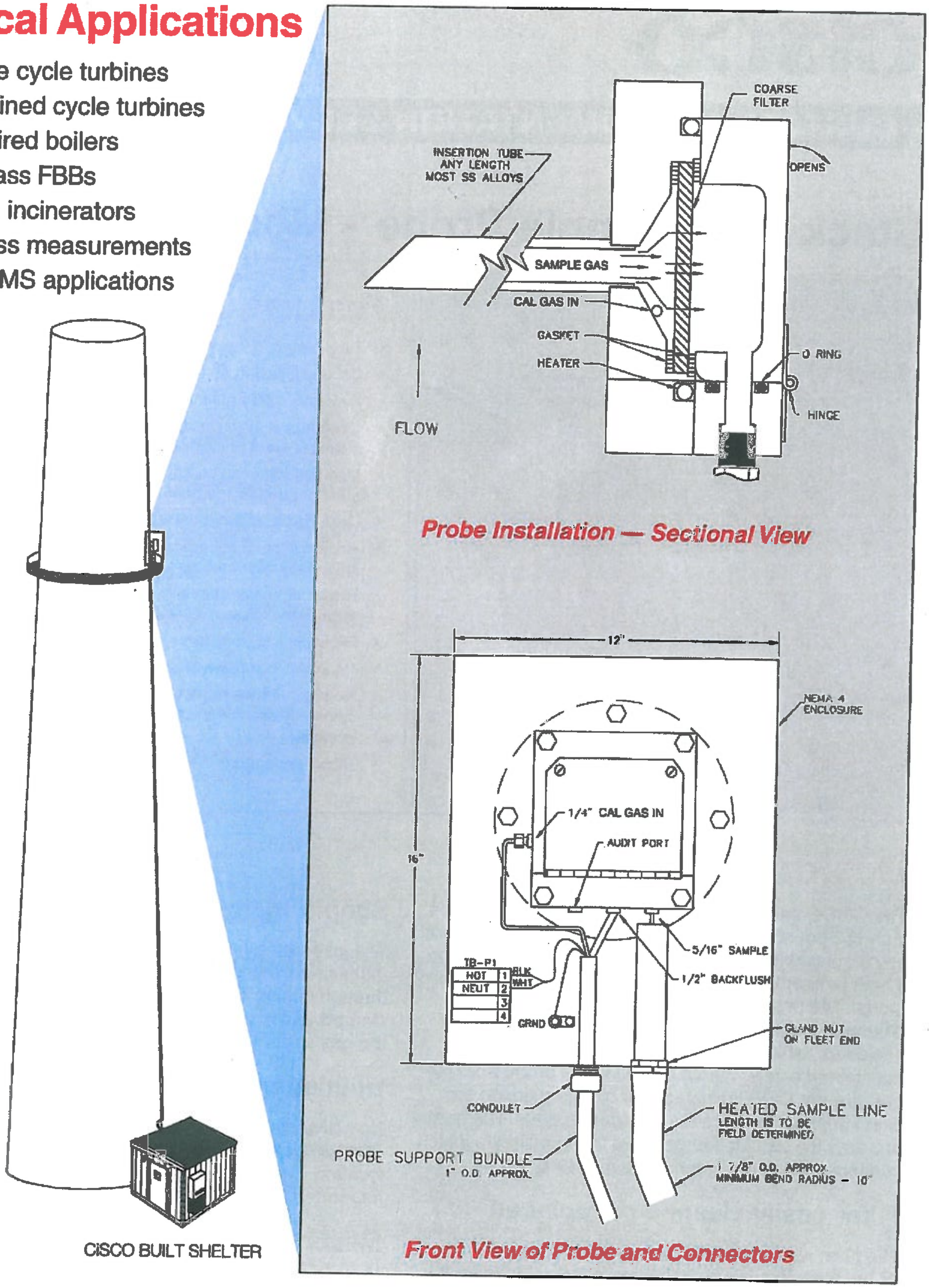
No active components are located at the sample probe. Plant utilities are not required at the sample probe location. The CISCO sample probe is completely supported from the analysis enclosure.

Meets regulatory requirements

CiSCO's sample probe is specially designed to meet federal and local environmental regulatory agency requirements for Continuous Emission Monitoring Systems (CEMS).

Typical Applications

- Simple cycle turbines
- Combined cycle turbines
- Coal fired boilers
- Bio-mass FBBs
- Waste incinerators
- Process measurements
- All CEMS applications



Probe Installation — Sectional View

Front View of Probe and Connectors

OFFERING "MADE TO MEASURE" CEMS SINCE 1985

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CiSCO

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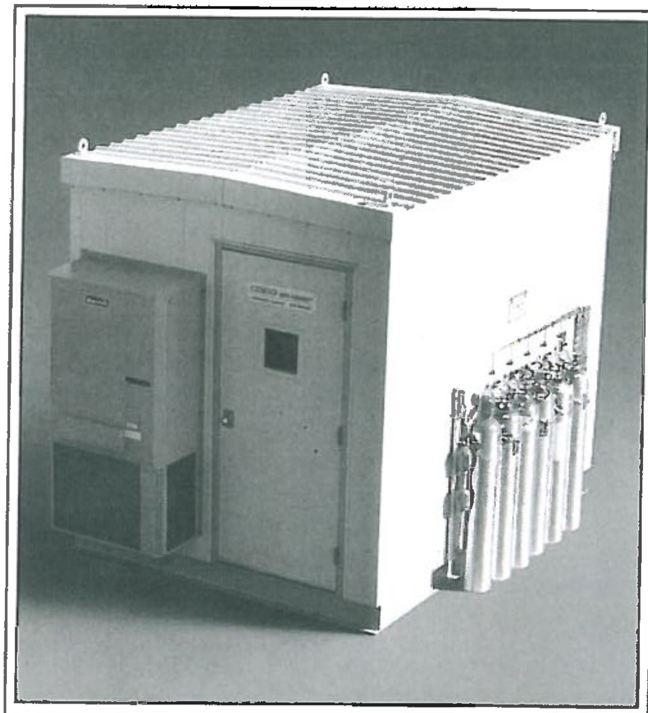
Custom CEMS Shelters



Features

- Custom built for your exact size and application
- Rugged welded steel frame with dust-tight interlocking steel side panels
- Twenty year exterior paint protection
- Climate controlled — industrial heating, air-conditioning, and R22 insulation provide stable environment
- Peaked roof promotes complete drainage
- Lifting "eyes" at all four corners facilitate handling
- No wooden or flammable materials
- Panic exit hardware on all doors and insulated, non-conductive, slip-resistant floor
- Bulkheads included for sample and calibration lines
- External junction box for plant wiring
- Class 1 Division 2 configurations available
- Meets or exceeds all applicable OSHA/NFPA/NEC and UL508 codes
- Easy, time saving site installation — ready to set on your slab or pad!

Design Description

CiSCO manufactures custom shelters to exacting standards to insure the proper environment for Continuous Emission Monitoring System (CEMS) equipment. Built of rugged, durable materials to meet size and application needs, CiSCO shelters provide a stable, clean, environmentally-controlled atmosphere for the operation and maintenance of the analysis system.

Unlike suppliers who use prefabricated housings, CiSCO designs and builds its own. This enables strict control of quality and consistency, while allowing CiSCO to offer many customized features that may not be available in other enclosures.

Improved CEMS performance

Every CiSCO shelter is designed to provide the perfect operating environment for analysis equipment and for the technicians who must maintain that equipment. CEMS housed in the proper setting are typically more predicable and trouble-free.

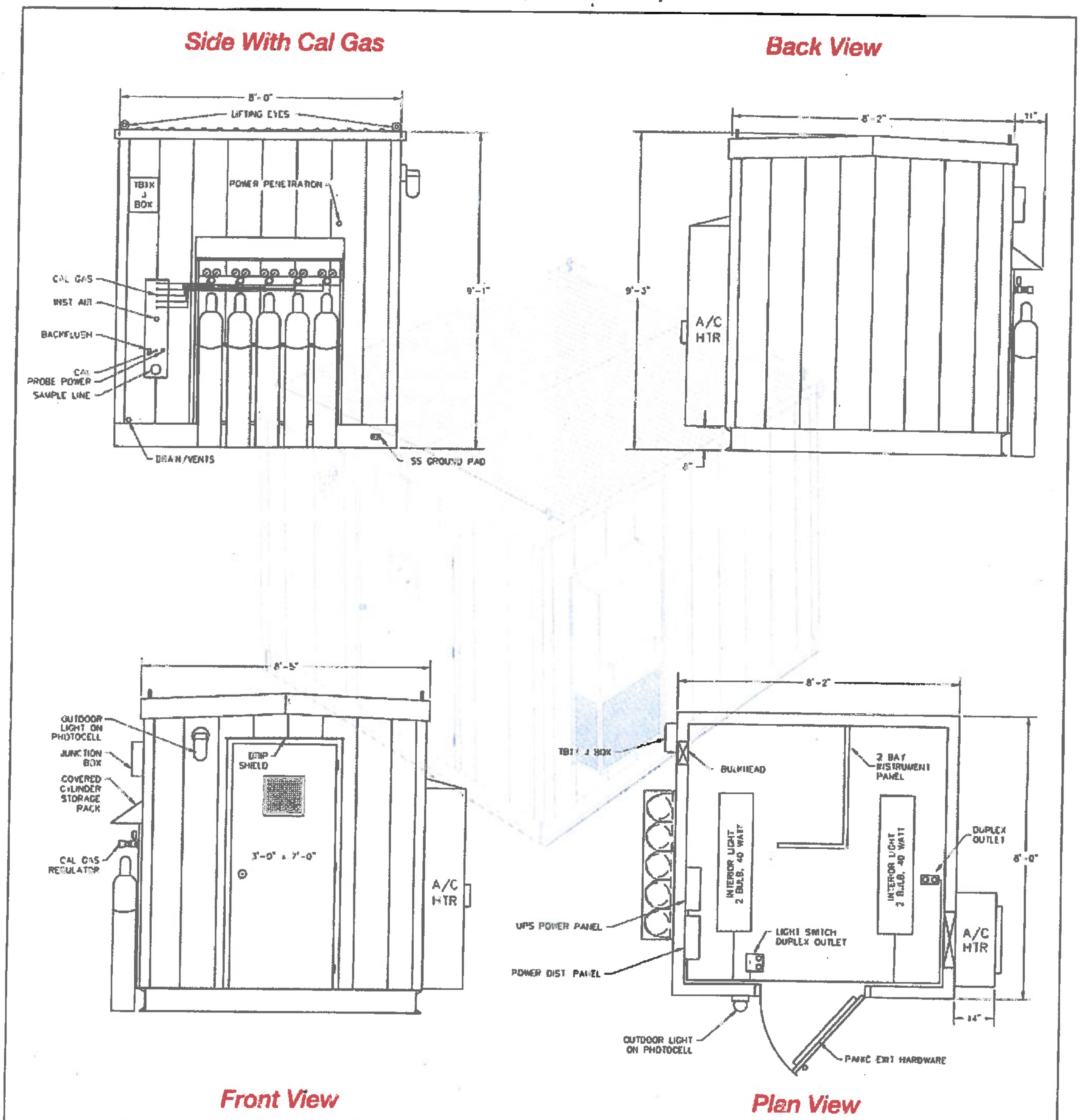
A convenient, temperature-stable, and pleasant working environment makes it easier for technicians to do their job. And, when CEMS get the care they need, maintenance costs are lower and uptime is higher.

Easy installation

Minimal field work is required to install a CiSCO shelter and startup the CEMS equipment. Each shelter is shipped on an open air-ride flatbed truck ready to hoist and place on a slab, pad, or other mounting. Typically, all that's needed to startup a system is to attach the heated sample line and probe support bundle. Then, connect utilities and a condensate drain. All necessary equipment is provided so a system can be ready to operate without delay. A hooded gas cylinder rack, complete with regulators and all connection hardware, is also included.

Made to last

CiSCO's shelters include a variety of useful features and rugged construction. The floors are 3/16" solid steel plate. Steel channels frame the bottom of the shelter and 3" square, 11 gauge corner posts support the side panels. Typical designs range from 8' x 8' (shown below) to 8' x 24'. Different heights, longer lengths and larger widths, up to 11', are also available. Safety features include panic exit hardware on the doors, non-conductive, slip-resistant flooring and smoke detectors. All shelters are complete with lighting, heating, air conditioning and utility connections. R22 insulation shields the walls, ceiling and floor, for all around protection.



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CISCO

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CeDAR by
Custom Instrumentation Services Corporation
Configurable Emissions Data Acquisition and Reporting

Benefits

- ***Broad Scope*** - CeDAR handles a wide variety of CEMS data, including multiple sources and fuels.
- ***Customized Screens*** - CeDAR displays data and trends from multiple sources and fuels, simultaneously.
- ***Flexible Reporting*** - CeDAR generates both standard and user-created customized reports.
- ***Security Options*** - CeDAR has several user configurable levels of security.
- ***Federal, State and Local Compliance*** - Complies with all (40CFR 60, 75, 51, 266, CAIR, NJ EER, PADEP, SJVAQMD and RECLAIM) data acquisition and reporting requirements.
- ***Wide Interface Capabilities*** – Compatible with PLCs (GE9030, Allen-Bradley PLC5, Control & CompactLogix, SLC500), MODBUS and OSI's PI Historian.
- ***Modifiable Database*** - CeDAR's database can be modified to meet new report generation requirements.
- **EPA Electronic Data Reporting (EDR)** – The ***breez75X*** software is compatible with ECMPS reporting requirements.
- ***Rapid Trouble Shooting*** - CeDAR systems allow for remote access with either VPN's or modems.
- ***Quality*** - CeDAR is built by CiSCO - building quality CEM systems is CiSCO's only business.

The CeDAR Solution, from CiSCO's Software Division

CeDAR is your best solution for data acquisition, display, storage and reporting of Continuous Emission Monitoring System (CEMS) data. Since CeDAR's 1998 launch, it has proven to be a highly configurable, user-friendly product, which will meet present and future data acquisition and reporting needs.

CeDAR's applications are broad in scope. Whether you have turbines, incinerators, boilers, smelters or furnaces, CeDAR can handle it. Whether your system is a multi-unit installation with multiple fuels and multiple combustion sources, or a single-fueled source, CeDAR can be configured to meet your needs.

CeDAR is versatile. CeDAR offers a wide variety of real-time user interface screens. It is built on a Windows® based platform and allows for multiple screen displays to be open and viewable at the same time. CeDAR can display quantitative numerical data simultaneously with trends, from multiple sources at the same time - in real-time. CeDAR is expandable. It comes with an array of standard reports and the ability to configure custom reports to meet your individual needs. The Report Design Wizard allows users to design, configure and store their own report designs and formats, as well as use the standard reports, provided with their system.

CeDAR has a comprehensive trending package that allows users to graph multiple parameters

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on a 10-second, one-minute, hourly or daily basis. The Value Editor allows operators to view, verify and edit a wide variety of data.

CeDAR provides three levels of security to limit access to different parts of the program. Security levels can be tailored to allow all users to change some settings or data, but limit other settings or data editing to only a select few.

Data can be archived to any mass storage device automatically or manually. Additionally, CeDAR is provided with an easy to use installation program so that if anything ever did go wrong with a DAHS computer, CeDAR can be reinstalled on another computer in minutes.

CeDAR complies with all federal, state and local (40CFR60, 75, 51, 266 and 503) data acquisition and reporting requirements, including RECLAIM, NJEER, PADEP and SJVAQMD. It can interface with popular PLCs including the GE9030, Allen-Bradley PLC's, (SLC 500, ControlLogix & CompactLogix), as well as MODBUS and PI Historians.

The Configurable Advantage

CeDAR provides distinct benefits to the end-user because of its flexible design. When permit requirements change or alterations to the site occur, simply contact CiSCO with your needs. CeDAR's configurable database can be altered to provide the data required for the site reporting needs. CeDAR's flexibility allows these changes to be completed in a short time.

Expansion Capabilities

CiSCO makes a continuous effort to satisfy customers with specialized applications. CiSCO satisfies these needs with compatible add-on modules such as the ***breez75X*** EDR reporting software compatible with ECMPS. Modules are simple to install and generally access data already provided by CeDAR.

CeDAR also provides users the ability to enter CGA/linearity data directly into the database.

Data can be viewed and analyzed. Reports can be printed and data exported to EDRs (or other reporting modules). Data can also be exported to any off the shelf spreadsheet, such as Microsoft Excel.

CiSCO is able to rapidly respond to upcoming needs because CeDAR is written using the latest Microsoft® development tools, making CeDAR's design more flexible and extensible.

Service, Support and Training

Because the best service is service you never need, CiSCO has developed CeDAR to be problem free. If you ever have a problem, a built-in modem or VPN connection allows CiSCO to diagnose and solve problems remotely. CeDAR was designed and built by CiSCO, not third party suppliers. Our 20+ years of CEMS experience means we build just what customers need today, with the flexibility to expand and change to meet their future needs.

The CeDAR software team teaches CeDAR from the ground up, at your site, or ours. Training is customized to the site's needs. Training can cover the basics of daily operation of the system or also include EDR reporting.

System Requirements

CeDAR operates on any PC using a Pentium®IV (or newer) CPU with Windows® 2000/XP/Vista operating systems. CeDAR performs well with 1 GB, or higher, of RAM.

Warranty

CeDAR software is warranted to be error free. If an error is found, we will fix it at no charge.

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APPENDIX 2

CALCULATIONS

Emissions corrected to 15% oxygen

To calculate emission concentration to a particular Oxygen concentration.

$$C_{adj} = C_d \times \frac{20.9 - XO_2}{20.9 - \%O_2}$$

Units: ppmvd

Reference: 40CFR60 Appendix A, Method 20, Eq. 20-4
CiSCO Formula ID 0010

- C_{adj} Emission concentration corrected to C percent O_2
- C_d Emission concentration measured dry, ppmvd
- X_{O2} Desired O_2% correction value. Typically 15% for turbines and 3% or 7% for boilers
- $\%O_2$ Oxygen percentage in flue gas, for $0 < O_2$ % < 20.0%

Emission Rate lb/mmBtu

To calculate emissions rate in lb/mmBtu from ppmvd.

$$E = C_d \times F_{d,gen} \times K \times MW \times \left(\frac{20.9}{20.9 - O_2\%}\right)$$

Units: lb/mmBtu

Reference: 40CFR60 Appendix A Method 19, Eq. 19-1
CiSCO Formula ID 0050

- E Emissions expressed as lb/mmBtu
- C_d Concentration measured, ppmvd
- $F_{d,gen}$ General Dry Fuel Factor, dscf/mmBtu (see formula F-7, F-7a, or prorating using Formula F-8)
- K Constant, 2.59E-9 (lb-mol/(dscf ppmvd))
- MW Molecular Wt (SO_2 64 lb/lb-mol, NO_2 46 lb/lb-mol, CO 28 lb/lb-mol, NH_3 17 lb/lb-mol)

Unmeasured Parameter Calculation

To calculate an unmeasured parameter based on user input values.

$$M_I = A \times HI$$

- M_I Mass emissions of pollutant, lb/hr
- HI Heat input to unit, mmBtu/hr
- A Emissions Factor, lb/mmBtu

SO_2 Mass Emission Rate Using 0.0006 lb/mmBtu

Use the following equation to calculate the SO_2 emission using the 0.0006 lb/mmBtu emission rate in 40CFR75 Appendix D 2.3.2 (7/1/97).

$$SO2_{rate} = ER \times HI_{rate}$$

Units: lb/hr

Reference: 40CFR75 Appendix D 3.3.2
CiSCO Formula ID D-5

- $SO2_{rate}$ Hourly mass emission rate of SO_2 from combustion of pipeline natural gas, lb/hr
- HI_{rate} Hourly heat input rate from combustion of a gaseous fuel, mmBtu/hr
- ER SO_2 emission rate from 40CFR75 Appendix D 2.3.1.1 and 2.3.2.1.1 lb/mmBtu

Notes:

Use the Gas Emission Factor (GEF) when calculating SO_2 lb/hr from fuel flow rate of "pipeline quality" natural gas. For pipeline natural gas. 0.0006 GEF, lb/mmBtu.
HI_{rate} derived in Formula F-20

Natural Gas Hourly Heat Input Rate mmBtu/hr

When the unit is combusting natural gas, use the following equation to calculate heat input from natural gas for each period. $$HI_g = \frac{Q_g \times GCV_g}{10^4}$$ Units: mmBtu/hr Reference: 40CFR75 Appendix F 5.5.2 CiSCO Formula ID F-20	• HI_g Hourly heat input from gaseous fuel, mmBtu/hour • Q_g Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet/hr. • GCV_g Gross calorific value of gaseous fuel, using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 or GPA Standard 2261-90, Btu/scf (incorporated by reference under 40CFR75 §75.6) • 10^4 Conversion of Btu to mmBtu and hundred standard cubic feet to standard cubic feet

CO_2 Mass Emission, Part 72 Method

In lieu of using the procedures, methods, and equations in 40CFR75 Appendix G 2.1, the owner or operator of an affected gas-fired unit as defined under 40CFR §72.2 may use the following equation and records of hourly heat input to estimate daily CO_2 mass emissions (in tons). $$W_{CO_2} = \left(\frac{F_c \times H \times U_f \times MW_{CO_2}}{2000}\right)$$ Units: tons/hr Reference: 40CFR75 Appendix G 2.3 CiSCO Formula ID G-4	• WCO_2 CO_2 emitted from combustion, tons/hour. • F_c Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1420 scf/mmBtu for crude, residual, or distillate oil and calculated according to the procedures in 40CFR75 Appendix F 3 3 5 • H Hourly heat input in mmBtu as reported in company records, see F-20. • U_f 1/385 scf CO_2/lb-mol at 14.7 psia and 68 F. • MW_{CO2} Molecular weight of carbon dioxide (44.0).

Calibration Correction

Calibration Correction	Corrected Concentration= Slope Factor * Raw concentration + Intercept Factor Slope Factor = $\frac{\text{Span Gas Value}}{\text{Span Response-Zero Response}}$ Intercept Factor = Actual Zero Response * Slope Factor

CUSTOM INSTRUMENTATION
SERVICES CORPORATION

LANGLEY GULCH POWER PLANT
NEW PLYMOUTH, IDAHO

CONTINUOUS EMISSIONS MONITORING SYSTEM QUALITY ASSURANCE MANUAL

CiSCO CEMS SYSTEM NO. 10009150

PREPARED BY:
CUSTOM INSTRUMENTATION SERVICES CORPORATION

PREPARED FOR:
IDAHO POWER COMPANY

November 8, 2010

Revision B

7841 SOUTH WHEELING COURT • ENGLEWOOD, COLORADO 80112
TEL: (303) 790-1000 FAX (303) 790-7292

QUALITY ASSURANCE MANUAL UPDATE LOG

DATE OF UPDATE	PAGES AFFECTED	INITIALS

TABLE OF CONTENTS

APPENDICES

LIST OF TABLES, FIGURES AND FORMS

1. GENERAL PROVISIONS

1.1. INTRODUCTION

1.1.1. CEMS Quality Assurance Policy

Langley Gulch Power Plant, located in New Plymouth, Idaho, is committed to operate in accordance with applicable federal and state environmental regulatory requirements and to ensure that environmental measurements are of high quality and reliability. For these reasons, this Quality Assurance (QA) Plan provides plant personnel, involved with the Continuous Emissions Monitoring System (CEMS) compliance program, with the procedures and guidance necessary to report accurate, precise, and reliable data.

This document is designed to fulfill the requirement in Condition 52 of the permit that the "permittee shall submit CEMS methodology and quality assurance and quality control protocols to DEQ for approval." A CEMS methodology has been prepared and submitted under separate cover.

This document is intended to remain dynamic and responsive to program improvements and regulatory changes occurring over time. For this reason, provisions for the maintenance of this QA Plan as a functional instrument are incorporated herein.

1.1.2. Purpose and Functions of the QA Plan

- Provide quality control (QC) procedures necessary to ensure maximum CEMS data capture, minimum instrument downtime, and high data quality.
- Provide the QC procedures necessary to assure compliance with applicable CEMS installation, operation and maintenance requirements, and the applicable requirements for the quarterly reporting of information to regulatory agencies.
- Define the data acceptance criteria and data quality requirements for the Langley Gulch Power Plant.
- Evaluate the adequacy of the QC procedures and data acceptance criteria through the use of periodic audits.
- Provide an effective mechanism to document and implement QA Plan revisions, as necessary, in response to audit findings, system improvements or changes to compliance program objectives.
- Serve as a resource for the overall coordination of the Langley Gulch Power Plant compliance program.

1.2. REFERENCES

Code of Federal Regulations, Title 40 Part 60, Subpart A (General Provisions)

Code of Federal Regulations, Title 40 Part 60, Subpart KKKK (Standards of Performance for Stationary Combustion Turbines

Code of Federal Regulations, Title 40 Part 60, Appendix A (Test Methods)

Code of Federal Regulations, Title 40 Part 60, Appendix B (Performance Specifications)

Code of Federal Regulations, Title 40 Part 60, Appendix F, Procedure 1 (Quality Assurance Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix A (Specifications and Test Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix B (Quality Assurance and Quality Control Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix D (Optional SO_2 Emissions Data Protocol for Gas-Fired Units and Oil-Fired Units)

Code of Federal Regulations, Title 40 Part 75, Appendix F (Conversion Procedures)

Code of Federal Regulations, Title 40 Part 75, Appendix G (Determination of CO_2 Emissions)

Code of Federal Regulations, Title 40 Part 98, (Mandatory Greenhouse Gas Reporting)

Custom Instrumentation Services Corporation (CiSCO) Continuous Emission Monitoring System (CEMS) Operations and Maintenance Manual, for the Langley Gulch Power Plant

Idaho Department of Environmental Quality, Air Quality Permit to Construct, Permit Number P-2009.0092.

Quality Assurance Handbook for Air Pollution Measurement Systems, Volume I: Principles: (EPA 600/9-76-0276)

Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III: Stationary Source Specific Methods; (EPA-600/4-77-027b)

1.3. DEFINITIONS

Bias - Systematic error, resulting in measurements that will be either consistently low or high relative to the reference value. A bias test following each 40 CFR 75 RATA (Relative Accuracy Test Audit) determines if a CEMS is biased.

Calibration Drift - The difference between the analyzer reading and a reference value after a period of normal operation (i.e., 24 hours) during which no unscheduled maintenance work took place.

Continuous Emission Monitoring System (CEMS) - The total equipment required for the determination and permanent recording of stack emissions at the Langley Gulch Power Plant.

Cylinder Gas Audit (CGA) - This test is required by 40 CFR Part 60 for the CO analyzer. It is a 2-point [low (20-30%) and mid (50-60%) of range] test using protocol gases. The test is run while the unit is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during the test. The test is conducted within three (3) trials. The difference between the reference gas and the analyzer measurement shall not vary more than ± 5% or 15 ppm, whichever is less restrictive.

Data Acquisition and Reporting System (DAHS) - The portion of the CEMS (software and hardware) that permanently records all monitored emission data (including CEMS analyzers, and plant signals).

Fuel Flowmeter Accuracy Test This test is required by 40 CFR Part 75 for fuel flowmeter is listed in 40 CFR 75 Appendix D Section 2.1.5. It is a 3-point [low (minimum), mid (approximately equally spaced between the minimum and the full range), and high scale (maximum) ranges] using and independent source as a comparison. The test is conducted within 3 trials. The difference between the reference and the fuel flowmeter measurement shall not vary more than ± 2%

IDEQ Idaho Department of Environmental Quality

Linearity Test - This test is required by 40 CFR Part 75 for NO_x and O_2 analyzers. It is a 3-point [low (20-30%), mid (50-60%), and high (80-100%) of range] test using protocol gases. The test is run while the unit is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during the test. The test is conducted within three (3) trials. The difference between the reference gas and the analyzer measurement shall not vary more than ± 5% or 5 ppm, whichever is less restrictive.

O&M Manual - CiSCO CEMS Operations and Maintenance Manual

Out-of-Control for CEMS

(1) Calibration Error (drift). A CEMS is out-of-control when calibration drift exceeds the limit of the applicable standard for any calibration. The out-of-control period begins with the hour of completion of the failed calibration error test and ends at the time of completion of an effective re-calibration.

(2) Linearity Check/CGA. A CEMS is out-of-control when the error in linearity or CGA at any of the gas concentrations in a quarterly linearity check or CGA exceeds the applicable standard. The out-of-control period begins with the hour of the failed check and ends with the hour of a satisfactory linearity check following corrective action. For NO_x CEMS, the

out-of-control designation applies if either of the component analyzers (NO_x or O_2) exceeds the applicable specification.

(3) RATA (Relative Accuracy Test Audit). An out-of-control period occurs if the relative accuracy results from a RATA exceed the applicable standard. The out-of-control period begins with the hour of completion of the failed RATA and ends with the hour of completion of a successful RATA, following corrective action.

Out-of-Control for Fuel Flowmeter

(1) Fuel Flowmeter Calibration - A fuel flowmeter is out-of-control when an accuracy test drift exceeds ± 2%. The out-of-control period begins with the hour of completion of the failed accuracy test and ends with the hour of completion following an effective re-calibration.

(2) Fuel Flowmeter Calibration - A fuel flowmeter is out-of-control when an accuracy test has expired. The out-of-control period begins with the hour within the quarter that the test was required and ends with the hour of completion of a successful accuracy test. The out-of-control period begins with the hour within the quarter that the test was required and ends with the hour of completion of a successful accuracy test.

Quality Assurance (QA) - The activities and procedures that are performed by or on behalf of the Langley Gulch Power Plant, to ensure that CEMS data meets USEPA and state criteria with respect to accuracy, precision, availability, and representation after the successful completion of the initial performance specification testing.

Relative Accuracy (RA) - A comparison of CEMS measurements and reference method test results. The CEMS measurements are compared to the results of EPA reference method testing performed in accordance with the procedures and criteria established in 40 CFR 60, Appendix A.

Span Value for 40 CFR 75 - Between 100% and 125% of the Maximum Potential Concentration (MPC) or the Maximum Expected Concentration (MEC).

USEPA or EPA - The United States Environmental Protection Agency.

1.4. SUMMARY OF APPLICABLE CEMS REGULATIONS

Langley Gulch Power Plant falls under the regulatory requirements listed in Section 1.2. The NO_x and O_2 analyzers fall nder the QA/QC requirements of 40 CFR 75. Appendix A of 40 CFR 75 requires an initial evaluation of the CEMS accuracy. This includes a Relative Accuracy Test Audit (RATA), 7-day Calibration Error Test, Cycle Time Test and Linearity Check. Appendix B of 40 CFR 75 requires periodic CEMS performance evaluations. This includes quarterly Linearity Checks and a semi-annual or annual Relative Accuracy Test Audit (RATA).

The CO analyzer falls under the requirements in 40 CFR 60, Appendix B and F and the Construction Permit. This includes an initial Relative Accuracy Test Audit (RATA) and 7-day Calibration Drift Test, quarterly Cylinder Gas audits (CGA) and annual Relative Accuracy Test Audit (RATA).

For 40 CFR 75, quarterly reports in the latest version of the electronic reporting format are due to EPA within 30 days of the end of the quarter. For 40 CFR 60, semiannual reports summarizing all recorded excess emission events and periods of monitor downtime must be prepared and submitted to the IDEQ. The results of all performance tests and audits conducted during the quarter must be included in both reports. All CEMS records, including raw, reduced and validated data, maintenance records, audit findings and written QA procedures must be maintained for a minimum of five years.

This quality assurance plan must be maintained in accordance with 40 CFR 75, Appendix B and 40 CFR 60, Appendix F. Specifically, the CEMS is designed to meet the regulations listed in Table 1.

TABLE 1 APPLICABLE PERFORMANCE SPECIFICATIONS

Pollutant	Regulation
NO_x	40 CFR 75, Appendix A, Section §3
O_2	40 CFR 75, Appendix A, Section §3
CO	40 CFR 60, Appendix B, Performance Specification 4/4a
Fuel Flowmeter	40 CFR 75, Appendix D, Section §2.15

The CEMS is used to determine compliance with the limits listed in the Air Quality Permit as shown in Table 2.

TABLE 2
AIR QUALITY PERMIT TO CONSTRUCT EMISSION LIMITS

Pollutant	Normal Operation	Low-Load Operation	Startup and Shutdown	Annual Emissions	Applicable Regulation
NO_x ppm @ 15% O_2, 3-hour rolling average	2.0	96	96	NA	PTC Section 33, 34, 35
NOx ppm @ 15% O_2, 30-day rolling average	15	96	NA	NA	PTC Section 37
NO_x Tons/Year	NA	NA	NA	88	PTC Section 36
CO ppm @ 15% O_2, 3-hour rolling average	2.0	24.5	NA	NA	PTC Section 33, 34
CO lb/hr	NA	NA	2510	NA	PTC Section 35
CO Tons/Year	NA	NA	NA	278.1	PTC Section 36
VOC ppm @ 15% O_2, 3-hour rolling average	2.0	11.5	NA	NA	PTC Section 33, 34

2. DESCRIPTION OF CEMS PROGRAM

2.1. PLANT DESCRIPTION

The Langley Gulch Power Plant is located near New Plymouth, Idaho. The site consists of a one-on-one combined-cycle plant, consisting of a natural gas-fired combustion turbine (CT) and a steam turbine. The CT is equipped with a heat recovery steam generator (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 increases steam production and steam turbine output for peak loads.

The unit is fired exclusively with pipeline quality natural gas and has an exhaust stack which discharges into the atmosphere approximately 160 feet above grade. The turbine has a maximum heat input of approximately 2134 mmBtu/hr at design conditions and generates 269 MW. The duct burner has a maximum heat input of approximately 241 mmBtu/hr at design conditions. The plant includes dry low NO_x combustors and selective catalytic reduction (SCR) to control NO_x emissions and a catalytic oxidation system to control CO emissions.

2.2. CEMS EQUIPMENT DESCRIPTION AND MEASURED PARAMETERS

The extractive CEMS supplied to the Langley Gulch Power Plant was manufactured by Custom Instrumentation Services Corporation of Englewood, Colorado. The CEMS is housed in a 10' x 10' metal shelter, located at the base of the stack. The shelter is climate controlled and provides a clean environment for the analyzers, system PLCs (programmable logic controllers) and other supporting equipment. The DAHS is located in the plant control room.

Table 3 shows the parameters measured by the CEMS. All analyses are performed on a "dry" basis from undiluted samples and are reported in lb/mmBtu, lb/hr, tons/year and ppm @ 15% O_2. Emissions are measured at the HRSG stack and at the catalyst inlet. The catalyst inlet analyzers are used for plant operations. The analyzers used in the CEMS are described in the following sections.

TABLE 3 MEASURED PARAMETERS

CT/HRSG	Units
NO_x	ppm, ppm @ 15% O_2, lb/mmBtu, lb/hr, tons/yr
CO	ppm, ppm @ 15% O_2, lb/mmBtu, lb/hr, tons/yr
O2	dry %
Natural Gas Flow Rate	hscf/hr
Catalyst Inlet*	**Units**
NO_x	ppm, ppm @ 15% O_2
CO	ppm, ppm @ 15% O_2
O2	dry %

* For plant use only

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2.2.1. Data Acquisition and Reporting System (DAHS)

The Data Acquisition and Reporting System (DAHS) used at the Langley Gulch Power Plant provides historical data storage with access to data for review and editing. It generates all required reports in the formats, which are acceptable to the EPA and the state. This includes hourly, daily, and monthly summaries, plus daily and quarterly exceedences data, automatically or on demand. The semi-annual report required by the state is generated and submitted within 30 days after the end of period. 40 CFR 75 quarterly reports in the most current electronic data reporting format are also generated by the DAHS. Sample reports are provided in Appendix 1.

The DAHS is designed to be placed in a Control Room environment. An IBM compatible desktop computer will store, manipulate, format, and archive the data. A color monitor, keyboard, printer, and modem are also included.

CeDAR™ software provided for data acquisition is an integrated, user-friendly, menu-driven software package developed by CiSCO for data acquisition, analysis, and reporting. Data acquisition will continue uninterrupted in the background while data manipulation and report generation is taking place in the foreground. Other software packages include the following:

- Windows for multitasking
- PCAnywhere for phone modem communications

The calculations of emissions in units of the applicable standards (See Table 3) are accomplished by the DAHS. The calculations used are provided in Appendix 2. The calculation to correct for calibration drift is also included in Appendix 2.

2.2.2. Oxides of Nitrogen Analyzer

For the analysis of NO_x, Teledyne (TAPI) Model 200EM analyzers are used. The Chemiluminescence detection method quantitatively converts NO to NO_2 by gas-phase oxidation with molecular ozone that is produced by the analyzer ozone generator in an environment, of system supplied dry instrument air. The Model 200EM converts NO_2 to NO by employing a converter cartridge filled with molybdenum (Mo, "moly") chips heated to a temperature of 600° F. The analyzer ranges configured into the system are given in Table 4.

2.2.3. Carbon Monoxide Analyzer

For the analysis of CO, Teledyne (TAPI) Model 300EM analyzers are used. The Model 300EM Gas Filter Correlation Carbon Monoxide analyzer is a microprocessor-controlled analyzer that determines the concentration of carbon monoxide (CO) in a sample gas drawn through the instrument. It requires that sample and calibration gasses be supplied at ambient atmospheric pressure in order to establish a stable gas flow through the sample chamber where the gases ability to absorb infrared radiation is measured.

The microprocessor uses the calibration values, the IR absorption measurements made on the sample gas along with data regarding the current temperature and pressure of the gas to calculate a final CO concentration. The analyzer ranges configured into the system are given in Table 4. Automatic range change is dependent upon concentration. All ranges are linearized within 0.1% with the microprocessor controlled electronics.

2.2.4. Oxygen Analyzer

For the analysis of Oxygen, the O_2 channel of the Teledyne (TAPI) Model 200 EM analyzer is used. This type of analyzer is characteristically linear and is not sensitive to interference from moisture, combustibles, or physical vibrations. A true gross oxygen analysis is provided. The analyzer ranges configured into the system are given in Table 4.

2.2.5. Fuel Flowmeter

The duct burner fuel flow meter will be a Rosemount compact orifice mass flowmeter model 3095MFCCS040N065T33CA1AQ4M5. The combustion turbine fuel flow meter will be a Triad (or equal) orifice plate meter tube with a Rosemount 2051 transmitter.

2.3. REPORTS

The reports generated for the Langley Gulch Power Plant are generated by the DAHS. Sample reports can be found in Appendix 1. All reporting is done in accordance with the requirements of 40 CFR 75 and the Air Quality Permit.

To meet the 40 CFR 75 requirements a quarterly report must be submitted to the EPA in electronic format. The file generated by the DAHS is in a prescribed format and includes emission and plant data for every hour in the quarter. Periods of missing data are substituted using EPA missing data procedures. The quarterly data is provided to the EPA electronically. The accuracy of the data being submitted is verified using Emissions Collection and Monitoring Plan System (ECMPS). This program verifies that all data is entered in the proper location and is in the proper format.

The Air Quality Permit requires that quarterly reports are submitted to summarize excess emissions and monitor information following the format in 40 CFR 60, Subpart KKKK. The information provided includes a summary of excess emissions, monitor downtime, and quarterly quality assurance test results. All monitoring data shall be kept on file for a period of at least five years and made available to agency personnel upon request.

- Unit Hourly Emissions Report - Summarizes minute totals/averages of mass emission and operating parameters for each hour.
- Unit Daily Emissions Report - Summarizes hourly totals/averages of mass emission and operating parameters for each hour in a 24-hour period.
- Unit Monthly Emissions Report - Summarizes daily emission rates and operating parameters for each month.
- Daily Fuel Report - Summarizes hourly fuel flow rates and usage for each hour in a 24-hour period.
- CEMS Downtime Report (daily, monthly, quarterly, or for a specified duration) - For each reported parameter, shows time and duration when plant is on-line and the CEMS is off-line.
- Excess Emissions Report (daily, monthly, quarterly, or for a specified duration) - Shows all parameter limit exceedences.
- CEMS Performance Summary - Summarizes downtime by reason and calculates excess emissions as a percentage of total source operating time.
- Emissions Data Summary - Summarizes exceedences by reason and calculates downtime as a percentage of total source operating time.
- Audit Report - Shows values for several parameters during a specified period of time.

- Raw Values Report - Shows raw values and monitor codes (in text and code number) for one parameter during a specified period of time.
- Calibration Reports Summarizes calibration results and calculates out-of-control conditions for each analyzer for each day.

2.4. ORGANIZATIONAL RESPONSIBILITIES

The organizational chart for the Langley Gulch Power Plant (Figure 1) shows the personnel responsible for QA activities. All identified plant personnel have a shared responsibility for the day-to-day operation, maintenance and quality assurance of the CEMS. The responsibilities for QA activities can be summarized as follows:

Manager, Power Production
- 40 CFR 75 designated representative.

Facility Contact
- Administer the QA Manual to ensure compliance, including checking QA results periodically and reviewing/updating the QA Manual as needed, but at least once per year
- Responsible, along with Plant Technician, for overall maintenance and inspection program. This includes checking QA results and reviewing maintenance procedures.
- Responsible for compiling reports sent out under company letterhead to the appropriate regulatory agencies. Printed reports originate from the CEMS DAHS and are compiled by the Plant Engineer and are forwarded to the DR and the Regulatory Agency.
- Responsible for the overall program including maintaining complete files of CEMS data, including records, reports, alarm printouts, QA forms, etc. All required information is stored for five years and shall be made available for inspection upon request. DAHS printed reports with a software back-up copy are archived. Any forms or documents that are not computer generated will be archived onsite.
- Responsible for electronically storing and maintaining all CEMS files, which includes, but is not limited to all records, reports, and QA forms.

Plant Technician
- Schedule and perform daily, weekly, monthly, quarterly, and annual maintenance defined in the QA Manual.
- Perform all required corrective actions needed to keep the CEMS operating within specifications, including service to correct out-of-control conditions, service required as a result of preventative maintenance checks, service due to CEMS alarm conditions, and service due to malfunctioning components. If an alarm condition cannot be corrected, the Plant Engineer and CEMS Manufacturer are contacted.
- Ensure that all required CEMS accuracy audits, including Linearity Checks, Cylinder Gas Audits (CGAs) and Relative Accuracy Test Audits (RATAs) are performed as required by applicable regulations. This may include retaining the services of an outside stack testing company or initiating corrective maintenance if a Linearity Check or RATA fails.
- Maintain the CEMS spare parts inventory at required levels to minimize downtime and data loss. Parts are obtained from the onsite warehouse or ordered from the manufacturer.

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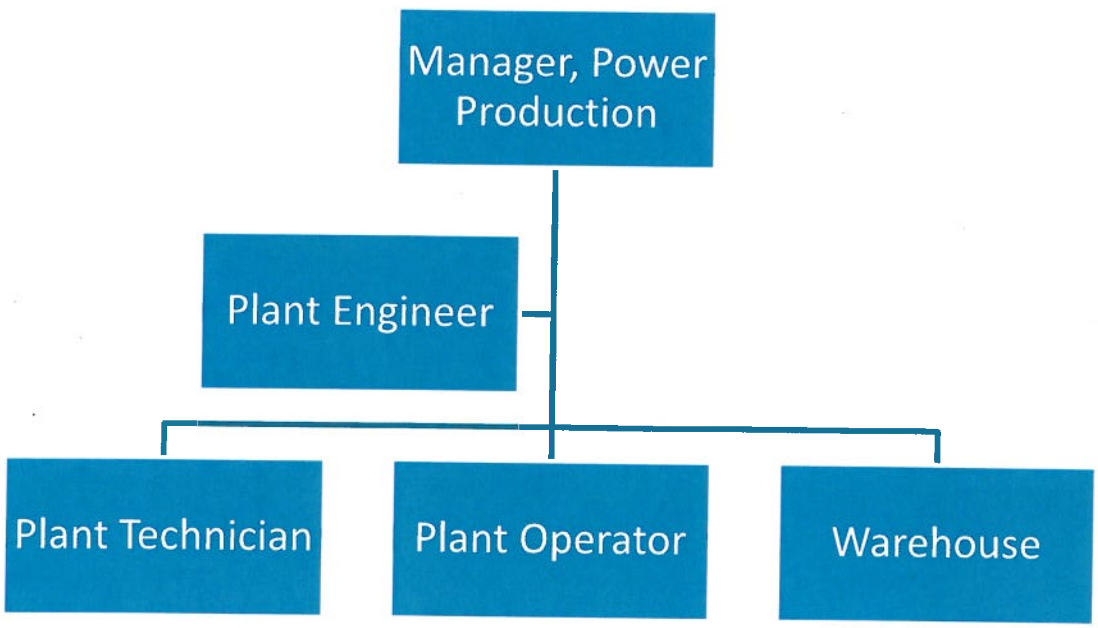
Plant Operator

- Monitor for CEMS alarms in the control room on a 24-hour basis. Alarms are investigated, and the appropriatecorrective actions are taken as needed. The events are documented in the DAHS with both reason for the alarm and the actions taken to correct the problem.
- Trouble shoot and attempt to correct alarm conditions, and notify Plant Technician if an alarm condition is not corrected.
- Maintain the supply of cylinder gases required for daily calibration drift tests and periodic CEMS assessment audits. This includes maintaining a permanent file of all cylinder gas certification documentation from the cylinder gas supplier.

Figure 1

Langley Gulch Power Plant Organizational Chart



3. QUALITY ASSURANCE REQUIREMENTS

The CEMS for the Langley Gulch Power Plant is designed to meet the reporting, record keeping, certification, and quality assurance requirements of 40 CFR 75 and the state Air Quality Permit.

3.1. DATA VALIDATION REQUIREMENTS

Personnel at the Langley Gulch Power Plant strive to achieve 95% availability of the monitors under normal operating conditions. All reasonable and practical means are used to achieve this objective, including overtime-corrective maintenance work, quarterly audits, routine preventative maintenance, and daily calibration checks. All pertinent regulations require the reduction of emissions to one-hour time-based emissions.

3.1.1. Invalid Data

Numerous conditions can render data invalid. If the correct numbers of valid data points are not collected for any reason, then the data collected is considered invalid. For 40 CFR 75 reporting, invalid data is automatically replaced by the DAHS. For 40 CFR 60 reporting, invalid data is reported as monitor downtime. The following are examples of conditions that could result in invalid data:

- CEMS control power failure
- Analyzer malfunction
- Water in sample
- Back flush cycle
- Last calibration fail
- Out-of-Service
- CEMS Off-line
- CEMS failed linearity test (out-of-control)
- CEMS failed relative accuracy (out-of-control)

3.1.2. Hourly Data Validation

a) The CEMS must complete a minimum of one cycle of operation (sampling, analyzing and data recording) for each successive 15-minute period. This is defined as a data point.

b) A valid hour of data is computed from four or more data points equally spaced over the one-hour period. Gaseous emissions data are reduced and recorded as one-hour averages. If one of the 15-minute periods (using four data points per hour) is invalid, the hour is considered invalid and the DAHS will replace the hourly data using the missing data procedures in 40 CFR 75 or will be recorded as monitor downtime.

c) For 40 CFR 75 reporting, during periods of calibration, quality assurance or maintenance activities, a valid hour consists of at least two data points separated by a minimum of 15 minutes. If the CEMS does not collect valid data in accordance with this criteria, then the missing data procedures must be used to replace the data. In order to perform calibrations, quality assurance or maintenance, the "out-of-service" periods should begin more than 30 minutes into an hour and end less than 30 minutes into the next hour. In this way, nearly 60 minutes of service can be performed on the system without impacting availability.

d) For quarterly 40 CFR 75 reporting, all missing or invalid data is automatically replaced by the DAHS following the procedures contained in 40 CFR 75, Subpart D (for NO_x) and Appendix D (for fuel flow).

e) After determination of the emissions in the proper reporting parameters, the emissions data is rounded off to the same number of significant digits as the emission limit or the number of significant digits required by EPA.

3.2. CEMS GAS ANALYZER CALIBRATION

The CEMS is equipped with manual and automatic, zero and span calibration capabilities. The automatic calibration routine is performed every 24 hours under the programmed control of the system PLC. In addition, a calibration can be started manually at any time with the activation of the "Cal Start" button provided on the Operator Interface Terminal (OIT).

In either mode, a "Cal-at-Cabinet" valve allows the operator to select one of two modes of calibration. With the valve in the cabinet position, calibration gas is injected directly into the sample flow control components and then into the analyzers. With the valve in the probe position, calibration gas is injected into the sample probe via the 1/4" Teflon calibration line in the probe support bundle. The calibration gas is then pulled through the sample conditioning subsystem just as the sample is, and the integrity of the entire system is checked. This is the normal mode that is used during the automatic calibration routine.

In the automatic calibration sequence, either manually or automatically initiated, the cal gas solenoid valves are automatically sequenced by the system PLC. The first four minutes of each five-minute period of gas flow is used for system stabilization. During the last minute, the analyzer response is interrogated by the PLC. Eleven values are read, five seconds apart, and are averaged for an average calibration reading. Initial programming has timed the calibration sequence, five minutes for zero and five minutes for each analyzer span.

If the calibration check passes, a new sample output correction factor is calculated for each analyzer at each sample point and is stored to be used during sampling until the next calibration. If the calibration fails, the calibration fail alarm is activated and the subsequent sample output signal(s) will be uncorrected for each failed analyzer. Programming for 40 CFR 75 allows a maximum ±1% difference from reference gas for O_2 and ±5% of span for NO_x. Programming for 40 CFR 60 allows a maximum ±20% of span for CO.

In order for the PLC to check the validity of a calibration and generate a fail or out-of-control signal if the analyzer response is outside of preset limits, it not only needs to know the actual analyzer response, it also must "know" a constant to compare it with. For zero, the constant is zero, and is stored in a register in the PLC. All analyzer span concentration values are input to the PLC via the OIT. The values are taken directly from the span gas cylinder certification sheets. The nominal span gas concentrations required for the Langley Gulch Power Plant are provided in Table 4.

TABLE 4 ANALYZER RANGES AND NOMINAL SPAN GAS CONCENTRATIONS

ANALYZER	FULL SCALE RANGE	40 CFR 75 SPAN	DAILY SPAN GAS
NO_x Low Range	0-10 ppm	0-10 ppm	8-10 ppm
NO_x High Range	0-150 ppm	0-150 ppm	120-150 ppm
CO Low Range	0-10 ppm	NA	5-10 ppm
CO Mid Range	0-50 ppm	NA	25-50 ppm
CO High Range	0-3000 ppm	NA	1500-3000 ppm
O_2	0-25 %	0-21 %	16.8-21 %

Calibration adjustment procedures for gas analyzers are provided in Appendix 3. The specific analyzer manufacturer's manuals are contained in the CEMS O&M Manual, which is incorporated here by reference.

3.3. CEMS INSTALLATION AND CERTIFICATION

The CEMS must meet the installation and initial certification criteria contained in the Air Quality Permit, 40 CFR 75, Appendix A, and 40 CFR 60, Appendix B. This includes a Relative Accuracy Test Audit (RATA) and 7-day calibration error tests on all analyzers. For 40 CFR 75 certification, linearity, response time, bias, and DAHS verification tests must also be performed.

Once certified, the CEMS is evaluated on a cyclical basis in accordance with the Quality Assurance and Quality Control Procedures under the following 40 CFR 75, Appendix B, 40 CFR 60, Appendix F and the Air Quality Permit.

3.3.1. Relative Accuracy Test Audit (RATA)

Relative Accuracy Test Audits (RATAs) are conducted on the CEMS as a part of an initial certification and as a semi-annual or annual quality assurance check. The test evaluates the accuracy of the CEMS. The RATA is performed by a third-party contractor stack sampling team that conducts reference method tests and data collection simultaneously with the CEMS. 40 CFR 75 Appendix A, Section 6.1.2 (a-c) requires, starting January 1, 2009, any Air Emission Test Body (AETB) conducting a RATA for Part 75 must adhere to the requirements of ASTMD D7036-04, and provide a credentialed "Qualified Individual" on-site for the duration of the testing. The reference method tests are performed in accordance with procedures in 40 CFR 60, Appendix A, Reference Method 3A (O_2), Method 7E (NO_x), and Method 10 (CO). Langley Gulch Power Plant is operated at the normal operating load during the RATA. The data from the CEMS DAHS is evaluated and compared with the data from the reference method test results as a part of the relative accuracy determination. A minimum of nine test runs are performed. A maximum of twelve runs may be performed. Three of the twelve runs may be rejected as only nine test runs are needed to determine relative accuracy. All relative accuracy test data is reported.

The relative accuracy (RA) specifications for each applicable regulation are in Table 5. The results of any RATA above the minimum standard result in the analyzer and CEMS being classified as out-of-control. In the event RATA results indicate an out-of-control period, the analyzers are re-calibrated, all problems are corrected, and another RATA is initiated immediately. Notice must be forwarded to the EPA and the state within 72 hours of the additional RATA test.

Under 40 CFR 75 , the results of the initial certification RATA determine if the next scheduled RATA must be conducted during the next six months or within 12 months. In the event the results from an initial or periodic RATA for the NO_x or O_2 CEMS are between 7.5% and 10.0% RA (relative accuracy), the next RATA test is required in the second quarter following the RATA per 40 CFR 75. In order to perform RATAs on an annual basis instead of a semiannual basis, the results from an initial or periodic NO_x or O_2 RATA must be less than or equal to 7.5% RA (relative accuracy).

For qualifying low NO_x emitters (<0.20 lb/mmBtu), the CEMS qualify for annual RATAs where the average analyzer value during a RATA is within 0.015 lb/mmBtu of the average reference method value (as per 40 CFR 75, Appendix B, 2.3.1).

TABLE 5 RELATIVE ACCURACY (RA) SPECIFICATIONS

Component	Regulation	Specification
NO_x lb/mmBtu	40 CFR 75 Appendix A 3.3.2 (semi-annual RATA)	≤10.0% RA of the mean value of reference method tests or ≤0.020 lb/mmBtu if level during RATA is ≤0.2 lb/mmBtu
	40 CFR 75 Appendix B § 2.3.1.2(f) (annual RATA)	≤7.5% RA of the mean value of reference method tests or ≤0.015 lb/mmBtu if level during RATA is ≤0.2 lb/mmBtu
CO ppm	40 CFR 60 Appendix B, Performance Specification 4/4a	10% RA 5% of emission standard +/- 5 ppm mean difference

3.3.1.1.RATA Calculations

The RATA is performed during initial certification or at least once a year, according to the Relative Accuracy Test procedure in the applicable Performance Specification. To evaluate RATA results, use the following procedure.

1. Calculate the arithmetic mean of the monitor or monitoring system measurement values.

2. Calculate the mean of the reference method values.

3. Using data from the automated DAHS, calculate the arithmetic differences between the reference method and monitor measurement data sets.

4. Calculate the arithmetic mean of the difference (Eq. A-7, 40 CFR 75, Appendix A, Section 7.5.1), the standard deviation (Eq. A-8 40 CFR 75, Section 7.3.2), the confidence coefficient (Eq. A-9), and the monitor or monitoring system relative accuracy (RA) using the equation below.

The relative accuracy for a RATA is defined as (Eq. A-10 40 CFR 75, Section 7.3.4):

$$RA \quad \frac{|\bar{d}| + |cc|}{RM} \times 100$$

Where:

RA	Relative accuracy of the CEMS, %
$|\bar{d}|$	Absolute value of the mean difference between the RM values and the CEMS values
$|cc|$	Absolute value of the confidence coefficient
RM	Average reference method (Arithmetic mean) value or applicable standard in lb/hr, lb/mmBtu or ppm

If the RATA results exceed the RA performance criteria, the CEMS is considered out-of-control. The appropriate personnel, designated in the Organizational Responsibilities section, must initiate corrective maintenance and arrange prompt follow-up testing after the corrective maintenance is completed.

3.3.1.2. 40 CFR 75 Bias Factor and Adjustment Factor

Following a RATA, the NO_x CEMS is tested for bias. The bias test requires the comparison of the mean difference (d) and the confidence coefficient (cc) determined when calculating the relative accuracy results. If the mean difference (d) is greater than the confidence coefficient (cc), the monitor or monitoring system has failed the bias test.

If the monitor or monitoring system fails the bias test standard ($d \geq cc$ and $RA \leq 10\%$), a Bias Adjustment Factor (BAF) is calculated using equation (Eq.) A-12 in 40 CFR 75, Appendix A. If the RA is greater than 10% but less than 20%, then an adjustment factor of 1.111 is used. The BAF and adjustment factor are applied to the associated CEMS data until the next RATA test or a repeat bias test shows a different bias factor. The BAF and adjustment factor are manually keyed into the CEMS DAHS for CEMS data adjustment and reporting.

The BAF is determined using the following equation (Eq. A-12 40 CFR 75, Section 7.6.5):

$$BAF \quad 1 + [\,|\bar{d}| \div CEM]$$

Where:

BAF	Bias Adjustment Factor (to the nearest 1000th)
$|\bar{d}|$	Arithmetic mean of the difference obtained during bias test using Equation A-7
CEM	Mean of the data values provided by the monitor during the bias test

3.3.2. 7-Day Calibration Error Test

The calibration error test verifies the ability of the CEMS to remain within calibration standards for a specified period of time without unscheduled maintenance, repair or adjustment. The calibration error test results are determined from the daily calibrations of the analyzers with two concentrations of calibration gas (zero-level and mid/high-level) performed approximately 24 hours apart for seven consecutive operating days. 40 CFR 75 defines an *operating day* as any day in which the unit combusts fuel. The calibration gases are injected at the CEMS extractive probe to verify the sample lines, sample conditioning, sample analysis, and data acquisition and handling system. The calibration error test is expressed as a percent of the span of the analyzer. The calibration error for the O_2 analyzers is expressed as the difference from the reference gas. The calibration error test performance specifications are listed in Table 6.

TABLE 6 7-DAY CALIBRATION ERROR TEST PERFORMANCE STANDARDS

GAS	FULL SCALE RANGE	40 CFR 75 SPAN	ZERO ERROR	SPAN ERROR
NO_x Low Range	10 ppm	10 ppm	$\leq \pm 2.5\%$	$\leq \pm 2.5\%$
NO_x High Range	150 ppm	150 ppm	$\leq \pm 2.5\%$	$\leq \pm 2.5\%$
CO Low Range	10 ppm	NA	$\leq \pm 5\%$	$\leq \pm 5\%$
CO Mid Range	50 ppm	NA	$\leq \pm 5\%$	$\leq \pm 5\%$
CO High Range	3000 ppm	NA	$\leq \pm 5\%$	$\leq \pm 5\%$
O_2	25%	21%	$\leq \pm 0.5\%\ O_2$	$\leq \pm 0.5\%\ O_2$

3.3.3. DAHS Verification Tests

The DAHS evaluation and certification include sample calculations to verify the following: (1) proper computation of all required emissions, (2) proper computation and application of the missing data substitution procedures, and (3) application of the bias adjustment factor. These tests are performed in accordance with EPA specifications.

3.3.4. 40 CFR 75 Cycle Time/40 CFR 60 Response Time Test

The cycle time/response time tests determine the time required for the CEMS to respond to a change in monitored gases. The response test includes the response through the entire sample transport, sample conditioning, analyzing and reporting system cycle of the CEMS. Tests are conducted with zero gas and high-level calibration cylinder gas.

While the source is operating and the CEMS is measuring and recording the stack concentrations, zero or high-level calibration gas is injected until a stable response is reached. The response time for the monitor to complete 95.0% of the concentration or emission rate step change at each gas concentration is recorded by the DAHS. Response times of less than 15 minutes are acceptable. The longer of the two cycle times (NO_x or O_2 analyzers) is the NO_x system response time.

Furthermore, to meet 40 CFR 60 Appendix B Performance Specification 4a requirements for ranges of 200 ppm or less, the CO analyzer is challenged with a zero gas and high level (50 to 100% of range) calibration gas. Both the upscale and down scale response time averages are determined. As stated in 40 CFR 60, Appendix B, PS 4a the response time to reach 95% of the respective reference gas values must be on average less than 1.5 minutes. The upscale and downscale time is the longer of the two analyzer response times.

3.3.5. Linearity Check

A linearity check is required on the NO_x and O_2 analyzers during the initial certification tests for 40 CFR 75. See section 3.6 Quarterly QA Assessments, for a description of the procedures.

3.4. FUEL METER INSTALLATION AND CERTIFICATION

The fuel flowmeter system must meet the installation and initial certification criteria contained in the operating permit and 40 CFR 75, Appendix D.

Once certified, the fuel flowmeter system is evaluated on a cyclical basis in accordance with the Quality Assurance and Quality Control Procedures under the following: 40 CFR 75, Appendix D and the operating permit.

3.4.1. Fuel Flowmeter Accuracy Test

The Fuel Flowmeter Accuracy Test (FFAT) is conducted on the fuel flowmeter as a part of an initial certification and at least once every four-calendar quarters for a quality assurance check. The test evaluates the accuracy of the meters.

For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of 2.0 percent of the upper range value (i.e. maximum fuel flow rate measurable by the flowmeter) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined using 40 CFR 75 Appendix D Section 2.1.5.1 of this appendix for initial certification in any of the following ways (as applicable): by design (orifice, nozzle, and venturi-type flowmeters, only) or by measurement under laboratory conditions; by the manufacturer; by an independent laboratory; or by the owner or operator. Flowmeter accuracy may also be determined using 40 CFR 75 Appendix D Section 2.1.5.2 by in-line comparison against a reference flowmeter.

TABLE 7: FUEL FLOWMETER TEST SPECIFICATION

Component	Regulation	Specification
FFAT	40 CFR 75 Appendix D Section 2.1.5	≤2% of full scale or upper range value

The accuracy for the FFAT is based on the reference value of the reference meter or device compared to the tested fuel flowmeter. The following equation is used:
Eq. D-1 (40 CFR 75, Appendix D)

$$ACC = \frac{|R-A|}{URV} \times 100$$

Where:

- ACC = Flowmeter accuracy at a particular load level, as a percentage of the upper range value.
- R=Average of the three flow measurements of the reference flowmeter.
- A=Average of the three measurements of the flowmeter being tested.
- URV=Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

The results must be forwarded in a timely manner to the regulatory agencies. The results can be submitted to the EPA electronically via the ECMPS Client Tool with the current quarterly emission submission or prior. Hardcopies are stored on-site for audit purposes.

TABLE 8: FUEL FLOWMETER TEST REQUIREMENTS

TEST	TEST REQUIREMENTS
FFAT	Report the date, hour, and minute that all test runs were completed.
	For laboratory tests not performed inline, report the date and hour that the fuel flowmeter was reinstalled following the test.
	It is required to test at least at three different levels: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads.

3.5. DAILY QA ASSESSMENT PLAN

3.5.1. Daily CEMS Calibration Error (Drift)

The daily calibration error (drift) test is used to evaluate the quality of the data collected by the CEMS. The CEMS is calibrated each day approximately 24-hours apart using zero-level and high-level concentration cylinder gases. Calibration error for the analyzers is determined as follows (Eq. A-5, 40 CFR 75, Appendix A).

$$CE = \frac{|R-A|}{S} \times 100$$

Where:
- CE — Calibration error as a percentage of the span
- R — Reference value of the zero or high-level cylinder gas
- A — Actual monitoring system response
- S — Span of the instrument

Calibration error for the O_2 analyzer is determined by the following formula.

CE |R A|

- CE — Calibration error as a percentage of the span
- R — Reference value of the zero or high-level cylinder gas
- A — Actual monitoring system response

The standards of performance for calibration error are summarized in Table 9. Reports of calibration error test results are printed daily. These reports must be filed for record keeping purposes. The calibration results are also archived by the CEMS data acquisition and handling system.

3.5.2. Daily Drift Requirements

For 40 CFR 75, the NOx and O2 analyzers are invalid when the calibration error exceeds the calibration fail limits in Table 9. The invalid period begins with the hour of completion of the failed calibration error test and ends with the hour of completion following an effective recalibration. In addition, an analyzer is considered out of control if a daily calibration has not been performed within 26-clock hours (2-hour grace period). Units that have been offline for more than 26-clock hours prior to doing an online calibration are permitted an 8-hour grace period from startup to perform an online calibration. 40 CFR 75 Appendix B 2.1.4 permits the use of a mean difference between the analyzer response and the calibration gas of 5 ppm for NO_x analyzers with spans of $\leq$50 ppm.

For 40 CFR 60, the CO analyzers are out-of-control if either the zero (low level) or high level calibration drift exceeds twice the applicable drift specification for five consecutive daily periods. If either the low-level or the high-level calibration drift result exceeds four times the applicable drift specification, the CEMS is out-of-control. The out-of-control period begins at the time corresponding to the completion of the fifth consecutive daily check with a drift in excess of two times the allowable limit or the time corresponding to the completion of a daily check in excess of four times the allowable limit. The end of the out-of-control period is the time corresponding to the completion of a calibration drift check following corrective action that results in the drift at both low and high levels being within the allowable limit.

TABLE 9 Analyzer Drift Specifications

GAS	Regulation	CALIBRATION FAIL	OUT-OF-CONTROL
NO_x Low Range	40 CFR 75	5.0 ppm	NA
NO_x High Range	40 CFR 75	10.0 ppm	NA
CO Low Range	40 CFR 60	1.0 ppm	2.0 ppm
CO Mid Range	40 CFR 60	5.0 ppm	10.0 ppm
CO High Range	40 CFR 60	300.0 ppm	600.0 ppm
O_2 (diluent)	40 CFR 75	1.0% O_2	NA

3.6. QUARTERLY QA ASSESSMENT

The following CEMS quality assessment is completed on the pollutant and diluent analyzers on a quarterly basis. Quarterly linearity checks must not be performed less than two months apart.

3.6.1. Linearity Checks/Cylinder Gas Audits

Pollutant and diluent analyzers undergo a quarterly cylinder gas audit (CGA) in three of four quarters each calendar year. A linearity check is required in every quality assurance operating quarter. A QA operating quarter is one in which the plant operates for 168 hours. Linearity checks are not required on NO_x analyzers with span values of 30 ppm or less.

The CGA requirements in 40 CFR 60, Appendix F are similar to the 40 CFR 75 linearity requirements except that only two levels of calibration gas are required (low and mid). A CGA is performed on analyzers with gases at 20-30% and 50-60% of full scale. A linearity check is performed on analyzers with gases at 20-30%, 50-60%, and 80-100% of span. The cylinder gases are injected at the base of the sample probe on the stack to assess the complete sample train. The quarterly linearity check uses cylinder gases prepared in accordance with EPA Protocol No. 1 procedures when they are being used to meet the 40 CFR 75 requirements.The data is collected by the DAHS.

It is critically important to regularly record and track the expiration of all cylinder gases used for quality assurance purposes. These dates may be entered on the line next to the cylinder number in the linearity/CGA settings of CeDAR Database Editor. Using expired gases can result in invalidating a quality assurance test in certain circumstances.

The accuracy for a CGA is based on the reference value of the cylinder gas concentration; the following equation is used (Eq. 1-1, 40 CFR 60, Appendix F). :

$$A = \frac{|C_m - C_a|}{C_a} \times 100$$

Where:

A Accuracy of analyzer, percent
C_m Average analyzer response during audit in appropriate units.
C_a Average audit value (certified value) in appropriate units.

Linearity error for the pollutant analyzers and diluent analyzers are determined as follows (Eq. A-4, 40 CFR 75, Appendix A, Section 7.1):

$$LE = \frac{|R - A|}{R} \times 100$$

Where:

LE Percent linearity error, based on the reference value
R Reference value of the cylinder gas (low, mid or high)
A Average of three monitoring system responses

The results must be forwarded in a timely manner to the regulatory agencies. The quarterly assessment report is due to the state and to the EPA not later than 30 days after the end of the quarter. The results of the three-point linearity check are provided in electronic format with the quarterly report. Documentation includes EPA Protocol No. 1 cylinder gas certifications that meet the concentration requirements. The gases required are listed in Table 10.

TABLE 10 AUDIT GASES

Analyzer	LOW	MID	HIGH
NO_x High Range	30-45 ppm	75-90 ppm	120-150 ppm
CO Low Range	2-3 ppm	5-6 ppm	8-10 ppm
CO Mid Range	10-15 ppm	25-30 ppm	40-50 ppm
CO High Range	600-900 ppm	1500-1800 ppm	2400-3000 ppm
O_2	4.2-6.3%	10.5-12.6%	16.8-21%

To perform the linearity check, each audit gas must take the same path as the sample gas. First the calibration gas bottles are put in place of the gases used for the daily zero and span check. Then, the manual calibration switch is pushed and the gas flows up the Teflon line in the probe support bundle and into the probe chamber. The gas is then drawn down the heated sample line and into the analyzers. The flow rates and pressures during the check should be the same as those during calibration. A detailed description of the linearity check procedures is located in the Langley Gulch Power Plant CEMS O&M Manual.

The difference between the actual concentration of the audit gas and the concentration indicated by the monitor is used to assess the accuracy of the monitoring data. The mean difference at all test points must meet the requirements listed below. Results of the check are kept on file at the plant and reported to the state and the EPA in the quarterly report.

3.6.2. Out-of-Control Linearity Error

An out-of-control period occurs when the error in linearity at any of the three concentrations exceeds the applicable standards as summarized below. The out-of-control period begins with the hour of the failed linearity check and ends with the hour of a satisfactory linearity check following corrective action and/or monitor repair.

NO_x — Error in linearity results are acceptable if they do not exceed or deviate from the reference values by more than 5%. Linearity results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average reference values is less than or equal to 5 ppm.

O_2 — Error in linearity results are acceptable if they do not exceed or deviate from 5% of the reference value <u>or</u> the absolute value of the difference between the average of the monitor response values and the average reference values must be less than or equal to 0.5% O_2, whichever is less restrictive.

3.6.3. Out-of-Control CGA 40 CFR 60

According to 40 CFR 60, Appendix F, a CO analyzer is considered out-of-control if the CGA results exceed ±15% of the gas value or ±5 ppm. The out-of-control period begins at the time corresponding to the completion of sampling for the CGA and ends at the time corresponding to the completion of a subsequent successful CGA, following corrective action. During an out-of-control period, CEMS data cannot be used to calculate emission compliance or counted towards meeting minimum data availability.

3.7. CEMS ANNUAL QA ASSESSMENT

See 40 CFR 75, Appendix B, Section 2.3.1 for Relative Accuracy Test Audit and 40 CFR 75, Appendix B, 2.3.3 for Bias Adjustment Factor information.

3.8. FUEL FLOWMETER ANNUAL QA ASSESSMENT

3.8.1. Fuel Flowmeter Accuracy Test

See Section 3.4.1 for Fuel Flowmeter Accuracy Test.

4. MAINTENANCE

4.1. GENERAL

Langley Gulch Power Plant requires a certain level of maintenance to assure a high level of confidence in the validity of the data. A good maintenance program prevents major and costly equipment failures and is required by the applicable regulations.

4.2. DAILY CALIBRATION CHECK

Once every day, an automatic calibration check is performed. The zeros and spans of the gas analyzers are compared to known concentrations of calibration gas. The calibration routine is part of the system timing function programmed into the system PLC and therefore, the time and frequency of each calibration can be field set. Refer to the CiSCO CEMS Operations and Maintenance Manual for further details.

Evaluation Procedure for Daily Calibration Reports

1. At the same time each day, the PLC is programmed to initiate an automatic calibration check. The results of these checks are printed on the Daily Calibration Reports. All monitor values are printed. (See the sample reports in Appendix 1.)

2. Collect the daily calibration reports and alarm printouts (See Organizational Responsibilities section).

3. Analyze the Daily Calibration Reports and Alarm Printouts (See Organizational Responsibilities section). If the monitors or analyzers are operating within specifications, the Daily Preventative Maintenance Checklist (Form 1) is completed to indicate that the calibration check is acceptable. If any problems are noted in any step of the process, immediately initiate corrective action to repair the component or analyzer (See Organizational Responsibilities section). All corrective actions must be documented, including problem description, actions taken, and as-left condition.

4. An automatic calibration check is always required after CEMS maintenance to provide documentation that the CEMS calibration is within specifications.

Procedure: Daily Gas Analyzer Calibration Drift Determination

Step 1: The CEMS computer is programmed to initiate an automatic calibration check at a preset time each day. When necessary, plant personnel can manually initiate the automatic calibration check function by pressing the Auto Calibrate Mode Switch. This will start an automatic calibration test sequence. This test mode takes approximately 15 minutes.

Step 2: After the test sequence is completed, observe the analyzer values that were recorded on the computer printout. The calibration values should have two sets of readings, zero and span check values.

Step 3: Check the calibration result values to determine if any analyzer failed calibration. If the monitors or analyzers are operating within specifications, the Daily Preventative Maintenance Checklist (Form 1) is completed to indicate that the calibration check is acceptable. Check CeDAR alarm log for failed calibrations.

Step 4: If an analyzer failed calibration, troubleshooting procedures must start immediately to correct the problem (See Organizational Responsibilities section). All corrective actions must be documented, including problem description, actions taken, and as-left condition.

a. After completing the troubleshooting procedure, repair the analyzer as necessary to insure calibration performance within the acceptable range.

b. Initiate a parts order to replace the faulty equipment as soon as possible.

c. Initiate the automated calibration check function to obtain a new computer printout of calibration values to ensure that the problem has been corrected.

Step 5: Record all steps taken to bring the CEMS into proper operating condition, including problem description, actions taken, and as-left condition.

4.3. DAILY PREVENTATIVE MAINTENANCE

The daily preventative maintenance checks include a review of the calibration error (drift) test results, a check of the calibration gas cylinders, plus visual checks and verification of various general items. The CEMS Daily Preventative Maintenance Checklist (Form 1) must be completed each day. If an item on the checklist is verified as operating within normal parameters, use the designation OK. If an item does not check out as operating within normal parameters, corrective action must be initiated and the corrective actions must be documented, including problem description, actions taken, and as-left condition. CiSCO has provided a record book for the CEM System that should be used to document all maintenance.

NOTES: When checking the supply of calibration gases, new calibration gas bottles should be ordered when the cylinder gas pressure gauge reads approximately 1000 psig. NOTE: All cylinder gas certification documentation must be filed for permanent reference when new cylinders are received at the plant.

CEMS DAILY PREVENTATIVE MAINTENANCE CHECKLIST

DATE ____________________ INITIALS ______________________

TIME STARTED __________________ TIME COMPLETED __________

UNIT # ________________________

	MON	TUES	WED	THURS	FRI	SAT	SUN
Calibration Error (Drift) Checks							
NOx Analyzer	____	____	____	____	____	____	____
CO Analyzer	____	____	____	____	____	____	____
O2 Analyzer	____	____	____	____	____	____	____
CEM Visual Inspections							
Bath temp & water level	____	____	____	____	____	____	____
Sample pumps, temp.	____	____	____	____	____	____	____
Printer paper supply	____	____	____	____	____	____	____
Panel flows & pressures	____	____	____	____	____	____	____
Log in Cal & problems	____	____	____	____	____	____	____
System Alarms	____	____	____	____	____	____	____
Calibration Gas Bottle Checks (High pressure, psig)							
NO_x low/ CO low	____	____	____	____	____	____	____
NO_x high / CO mid	____	____	____	____	____	____	____
CO high	____	____	____	____	____	____	____
O_2	____	____	____	____	____	____	____

COMMENTS:

FORM 1

4.4. PERIODIC TEST AND PREVENTATIVE MAINTENANCE CHECKLISTS

The following Periodic Test and Preventative Maintenance Checklists (Forms 2 through 5) list the procedures that must be performed each month, every three months, every six months, and every year to complete the recommended maintenance. Some items on the maintenance sheets, such as filter checks, may not exhibit a failure condition until damage to other components has resulted. These items require caution in determining replacement frequency. Close and continuous observation of the operating characteristics of the system, with particular notation of any shift, either sudden or prolonged, in one direction, of any of the many visual indicators in the system should prompt a maintenance response to prevent loss of data and/or equipment damage.

CEMS alarms indicate that service is required. They do not necessarily indicate that data is invalid. They do announce that the system is operating outside of design tolerance and incorrect data and equipment damage will occur if the system is allowed to continue operation without corrective action. For this reason, the alarms should be exercised on a regular basis to assure that they are operational. All alarm conditions require correction in a timely manner.

One of the best indications of system performance is the validity of the data being generated. The CEMS is programmed to conduct a calibration error (drift) test once every 24 hours. Daily scrutiny of these results will dictate whether or not maintenance is needed. As part of a good maintenance program, a stock of spare parts must be kept on site and available at all times.

The Periodic Test and Preventative Maintenance Checklists (Form 2 through 5) are used to direct and record maintenance activities. Each one must be completely filled out and maintained as part of the CEMS records. Many maintenance items on the checklists have a corresponding Periodic Test Procedure (PTP) or Preventative Maintenance Procedure (PMP) that provides detailed instructions. The correct PTP or PMP numbers are referenced on the checklist for those items. Periodic Test Procedures (PTPs) and Preventative Maintenance Procedures (PMPs) are provided in Appendices 3 and 4.

4.5. CORRECTIVE ACTION FOR A MALFUNCTIONING CEMS

Due to the complexity of the CEMS, a detailed written procedure is not provided for a malfunctioning system, analyzer, monitor or component in this manual. Each problem must be evaluated by trained plant personnel utilizing the CEMS Operations and Maintenance Manual (which is incorporated here by reference) and/or factory assistance.

It is recommended that zero and span calibration error (drift) tests be conducted immediately prior to any maintenance and a calibration must be performed after any maintenance. If the post-maintenance zero or calibration error (drift) test shows excessive drift, corrective action and recalibration must be conducted to bring the CEMS within specifications. All corrective action activities will be documented and will include problem description, actions taken, and as-left condition. Data is out-of-control if the daily calibration drift is greater than limits shown in Table 9.

4.6. SPARE PARTS INVENTORY

A recommended spare parts inventory is listed in the CiSCO CEMS O&M Manual. Refer to the Organizational Responsibilities section for person responsible for maintaining spare parts inventory.

CEMS MONTHLY/PERIODIC TESTING CHECKLIST
FOR LANGLEY GULCH POWER PLANT

UNIT # ______________________ DATE ______________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
GENERAL:					
Check Water Bath Level					
EXERCISE ALARMS:					
Shelter Temp Transmitter Alarm Test (PTP# 2c, Rev 0)					
Sample Vacuum Alarm (PTP# 3, Rev 4)					
Water Alarm (PTP# 4, Rev 4)					
Air Pressure Alarm (PTP# 5, Rev 4)					
Heated Sample Line Temp Alarm (PLC controlled line) (PTP# 6c, Rev 1)					
Low Cylinder Pressure Alarm (PTP# 15, Rev 0)					

COMMENTS:

FORM 2

CEMS 3-MONTH PREVENTATIVE MAINTENANCE CHECKLIST FOR LANGLEY GULCH POWER PLANT

UNIT #______________________ DATE ______________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
Replace Fine Sample Filters (PMP #1)					
Exercise Flow Meters (PMP# 2)					
Exercise Pressure Regulators (PMP# 3)					
Change Primary and Secondary Air Filter (PMP# 6)					
Change AC Filters (PMP# 8b)					
Change Drain Pump Tubing (PMP# 11)					
Complete Monthly Checklist					
Complete CGA/Linearity Error Tests					

COMMENTS:

FORM 3

CEMS 6-MONTH PREVENTATIVE MAINTENANCE CHECKLIST FOR LANGLEY GULCH POWER PLANT

UNIT #_______________ DATE _______________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
Check/Replace Filter Holder Seal (PMP# 12)					
System Leak Test (PMP# 21)					
Complete Monthly Checklist					
Complete 3-Month Checklist					
Complete RATA testing ***if a semiannual RATA is required***					

COMMENTS:

FORM 4

CEMS ONE-YEAR PREVENTATIVE MAINTENANCE CHECKLIST FOR LANGLEY GULCH POWER PLANT

UNIT # ______________________ DATE ____________________

MAINTENANCE ITEM	STATUS	START TIME	END TIME	INITIALS	COMMENTS
Change HRSG Probe Filter /Seals (PMP# 4)					
Clean Heated Sample Lines (PMP# 7)					
Change Membrane Dryer (PMP# 9)					
Replace Air Dryer Tower (PMP# 10)					
Rebuild Sample Vacuum Pump as needed (PMP# 13)					
Change SCR Inlet Probe Filter /Seals (PMP# 17)					
Change Ammonia Scrubber (PMP# 22)					
Calibrate fuel flow meters to 2% accuracy					
Complete Monthly Checklist					
Complete 3-Month Checklist					
Complete 6-Month Checklist					
Complete RATA testing					

COMMENTS:

FORM 5

APPENDICES

APPENDIX 1

DAHS REPORT FORMATS

Not currently available

APPENDIX 2

CALCULATIONS AND CALIBRATION PROCEDURES

FORMULAS

Correct ppm to 15% oxygen

To calculate emission concentration to a particular Oxygen concentration.

$$C_{adj} = C_d \times \frac{20.9 - XO_2}{20.9 - \%O_2}$$

Units: ppmvd

Reference: 40CFR60 Appendix A, Method 20, Eq. 20-4
CiSCO Formula ID 0010

- C_{adj} — Emission concentration corrected to C percent O_2
- C_d — Emission concentration measured dry, ppmvd
- X_{O2} — Desired O_2% correction value. Typically 15% for turbines and 3% or 7% for boilers
- $\%O_2$ — Oxygen percentage in flue gas, for $0 < O_2$ % < 20.0%

Emission Rate lb/mmBtu

To calculate emissions rate in lb/mmBtu from ppmvd.

$$E = C_d \times F_{d,gen} \times K \times MW \times \left(\frac{20.9}{20.9 - O_2\%} \right)$$

Units: lb/mmBtu

Reference: 40CFR60 Appendix A Method 19, Eq. 19-1
CiSCO Formula ID 0050

- E — Emissions expressed as lb/mmBtu
- C_d — Concentration measured, ppmvd
- $F_{d,gen}$ — General Dry Fuel Factor, dscf/mmBtu (see formula F-7, F-7a, or prorating using Formula F-8)
- K — Constant, 2.59E-9 (lb-mol/(dscf ppmvd))
- MW — Molecular Wt (SO_2 64 lb/lb-mol, NO_2 46 lb/lb-mol, CO 28 lb/lb-mol, NH_3 17 lb/lb-mol)

Unmeasured Parameter Calculation

To calculate an unmeasured parameter based on user input values.

$$M_l = A \times HI$$

- M_l — Mass emissions of pollutant, lb/hr
- HI — Heat input to unit, mmBtu/hr
- A — Emissions Factor, lb/mmBtu

SO_2 Mass Emission Rate Using 0.0006 lb/mmBtu

Use the following equation to calculate the SO_2 emission using the 0.0006 lb/mmBtu emission rate in 40CFR75 Appendix D 2.3.2 (7/1/97).

$$SO2_{rate} = ER \times HI_{rate}$$

Units: lb/hr

Reference: 40CFR75 Appendix D 3.3.2
CiSCO Formula ID D-5

- $SO2_{rate}$ — Hourly mass emission rate of SO_2 from combustion of pipeline natural gas, lb/hr
- HI_{rate} — Hourly heat input rate from combustion of a gaseous fuel, mmBtu/hr
- ER — SO_2 emission rate from 40CFR75 Appendix D 2 3 1 1 and 2.3.2.1.1 lb/mmBtu

Notes:

Use the Gas Emission Factor (GEF) when calculating SO_2 lb/hr from fuel flow rate of "pipeline quality" natural gas. For pipeline natural gas 0.0006 GEF, lb/mmBtu.
HI_{rate} derived in Formula F-20

Natural Gas Hourly Heat Input Rate mmBtu/hr

When the unit is combusting natural gas, use the following equation to calculate heat input from natural gas for each period. $$HI_g = \frac{Q_g \times GCV_g}{10^4}$$ Units: mmBtu/hr Reference: 40CFR75 Appendix F 5.5.2 CiSCO Formula ID F-20	• HI_g Hourly heat input from gaseous fuel, mmBtu/hour • Q_g Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet/hr. • GCV_g Gross calorific value of gaseous fuel, using ASTM D1826-88, ASTM D3588-91, ASTM D4891-89, GPA Standard 2172-86 or GPA Standard 2261-90, Btu/scf (incorporated by reference under 40CFR75 §75.6) • 10^4 Conversion of Btu to mmBtu and hundred standard cubic feet to standard cubic feet

CO_2 Mass Emission, Part 72 Method

In lieu of using the procedures, methods, and equations in 40CFR75 Appendix G 2 1, the owner or operator of an affected gas-fired unit as defined under 40CFR §72.2 may use the following equation and records of hourly heat input to estimate daily CO_2 mass emissions (in tons). $$W_{CO_2} = \left(\frac{F_c \times H \times U_f \times MW_{CO_2}}{2000}\right)$$ Units: tons/hr Reference: 40CFR75 Appendix G 2.3 CiSCO Formula ID G-4	• WCO_2 CO_2 emitted from combustion, tons/hour. • F_c Carbon based F-factor, 1040 scf/mmBtu for natural gas; 1420 scf/mmBtu for crude, residual, or distillate oil and calculated according to the procedures in 40CFR75 Appendix F 3.3.5 • H Hourly heat input in mmBtu as reported in company records, see F-20. • U_f 1/385 scf CO_2/lb-mol at 14.7 psia and 68 F. • MW_{CO2} Molecular weight of carbon dioxide (44.0).

Calibration Correction

Calibration Correction	Corrected Concentration= Slope Factor * Raw concentration + Intercept Factor Slope Factor = $\frac{\text{Span Gas Value}}{\text{Span Response-Zero Response}}$ Intercept Factor = Actual Zero Response * Slope Factor

CALIBRATION PROCEDURES

To calibrate the CEMS gas analyzer, use the following procedures.

1. Verify that the following system switches, pressures, and flows match the typical settings.

RANGE SWITCHES	TYPICAL SETTINGS
NO_x Analyzer	0-10/150 ppm
CO Analyzer	0-10/50/3000 ppm
O_2 Analyzer	0-25%

PRESSURES	TYPICAL SETTINGS
Bypass (Stack)	5-6 psi
$NO_x/CO/O_2$ Sample	2-4 psi
Dry Air	15 psi
Gas Cylinder Regulator	12 psi

FLOWS	TYPICAL SETTINGS
NO_x/O_2 Sample (Stack)	3 L/M
Stack Calibration	5-9 L/M
Purge Air	9-10 L/M

2. Perform individual analyzer calibration adjustments using the procedures found in the CEMS Operations and Maintenance Manual, which are incorporated in this QA Manual by reference.

3. Initiate an automatic calibration check and verify that the calibration drift for each gas analyzer is within acceptable limits. If not, perform corrective maintenance as needed and repeat the calibration check until a satisfactory result is achieved.

APPENDIX 3

PERIODIC TEST PROCEDURES

PERIODIC TEST PROCEDURE

TITLE: Bath Temp Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

BATH TEMPERATURE ALARM-DESCRIPTION

A thermal switch mounted on the lid of the refrigeration-cooled cold-water bathtub monitors the temperature of the water. Should the temperature of the water rise too high, above 40°F (4°C) the "Bath Temp" alarm will be activated. This alarm will also come on should the level of the water in the tub drop, due to evaporation or leakage. The switch is normally open and is held closed when immersed in cool water. The switch will open at temperatures above 40°F (4°C). If the switch does not open above 40°F (4°C), please call CiSCO Field Service (303-790-1000).

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Remove water bath cover so the temperature sensor is out of the water, allow time to let the sensor acclimate. Keep the sensor in alarm status for at least 30 seconds.
3) Verify that the "Bath Temp" alarm appears on the local operator interface terminal.
4) Check water bath level before putting cover back on.
5) Place the CEM System back "in-service."
6) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
7) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE

TITLE: Shelter Temperature Transmitter Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: Heat Gun, Can Freeze Mist

SHELTER TEMPERATURE TRANSMITTER ALARM - DESCRIPTION

A thermocouple with a 4-20mA transmitter is used to monitor the temperature inside the rack. Temperature is transmitted to the PLC, which will compare it to coded set points of 50°F (10°C) and 95°F (35°C). Historical data is available in the DARS/DAHS.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS and indicate maintenance.
2) Locate the thermocouple with temperature transmitter near top of the rack/cabinet (see Figure 2.3).
3) Using the heat gun, increase the temperature of the thermocouple above 95°F (35°C). Keep the sensor in alarm status for least 30 seconds.
4) Verify that the "High Shelter Temp" alarm appears on the local operator interface terminal.
5) Remove heat source.
6) Apply "Freeze Mist" or equivalent to thermocouple to reduce the temperature below 50°F (10°C). Keep sensor in alarm for at least 30 seconds.
7) Verify the "Low Shelter Temp" alarm on the local operator interface terminal.
8) Wait for alarm to clear after removal of cold temp source.
9) Place the CEM System back "in-service."
10) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
11) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE

TITLE: Sample Vacuum Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 9/16" wrench, ¼" plug

SAMPLE VACUUM ALARM-DESCRIPTION

A vacuum switch monitors the sample vacuum on the input to the sample pump. The vacuum switch is typically set to activate at 7 to 8 inches Hg (178 to 203 mm of Hg) and can be field adjusted. The switch is normally open and will close as the sample vacuum reaches its preset value. This alarm will activate on the operator interface terminal. If adjustment is required, please call CiSCO Field Service (303-790-1000).

Note: Each vacuum setting is system specific and the 7 to 8 inches of Hg (178 to 203 mm of Hg)may vary.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Remove ¼ flex tubing on inlet of fine sample filter assembly (see Figure 3.1)
3) Plug inlet fitting in filter assembly using ¼" tube plug. Keep in alarm status for at least 30 seconds.
4) Verify that the "Sample Vacuum" alarm appears on the local operator interface terminal.
5) Remove ¼" tube plug and reconnect the line.
6) Place CEM System "back in-service."
7) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
8) Perform PMP #21, System Leak Check.
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE
(CONT'D)

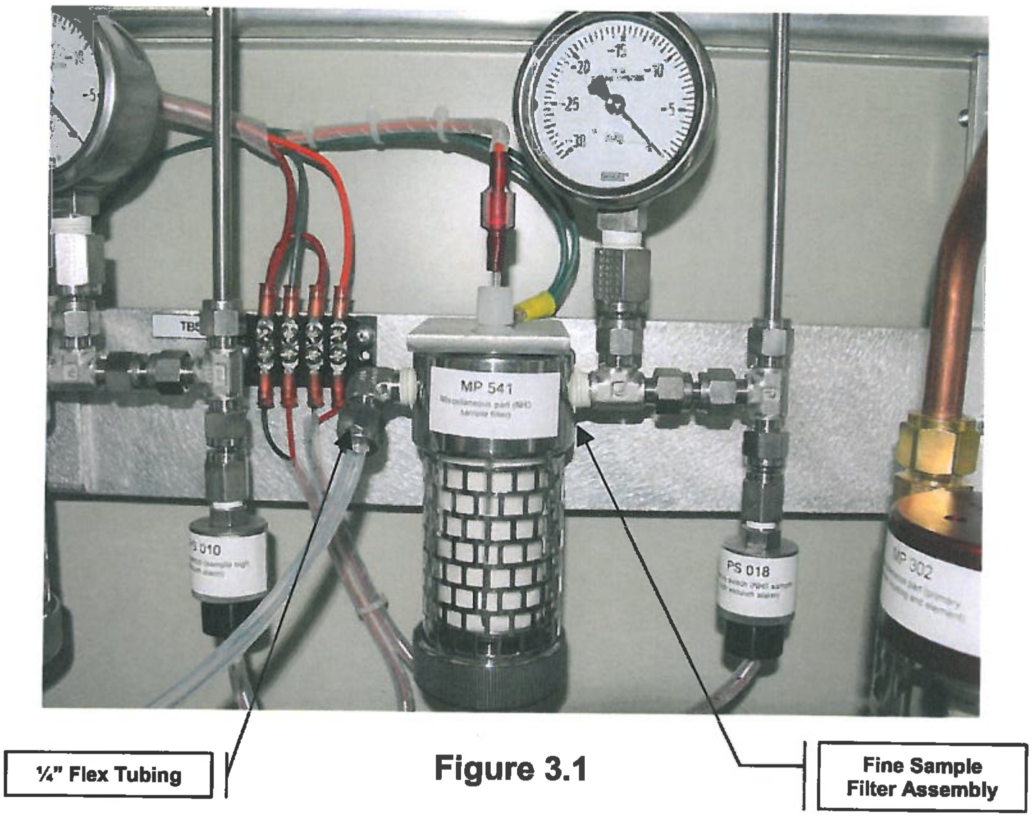


Figure 3.1

PERIODIC TEST PROCEDURE

TITLE: Water Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 10" jumper wire

WATER ALARM-DESCRIPTION

A sensor located in the fine sample filter will sense the presence of condensate through the conductivity to ground provided by the condensate. A "Water" alarm will be activated for the affected sample train if condensate is detected. This is given high priority to prevent damage to the system caused by allowing condensate to contaminate the sampling system. The sample pump will be automatically shut off if the water alarm is activated. To clear the water alarm and reactivate the sample pump, the alarm condition must be reviewed and the out-of-service button must be momentarily activated. Activation of this alarm is indicated on the interface terminal

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Remove the knurled lower flange and glass cylinder or fine sample filter assembly (see Figure 4.1).
3) Ground condensate probe for 10 seconds by using a jumper (see Figure 4.2).
4) After 10 seconds, the alarm will be verified in the PLC and the sample pump will shut off.
5) Verify that the "Water" alarm appears on the local operator interface terminal.
6) Remove jumper. Replace the knurled lower flange and glass cylinder. Be careful when tightening nut assembly. Excessive tightening can break glass filter assembly.
7) Perform PMP #21, System Leak Check.
8) Place CEM System back "in-service", back "out-of-service" and then back "in-service" to reactivate sample pump.
9) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
10) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

Note: This test just gives an indication that the circuit is functioning. Test procedure can be performed in conjunction with PMP #1. Refer to the Summarized Maintenance Schedule.

PERIODIC TEST PROCEDURE
(CONT'D)

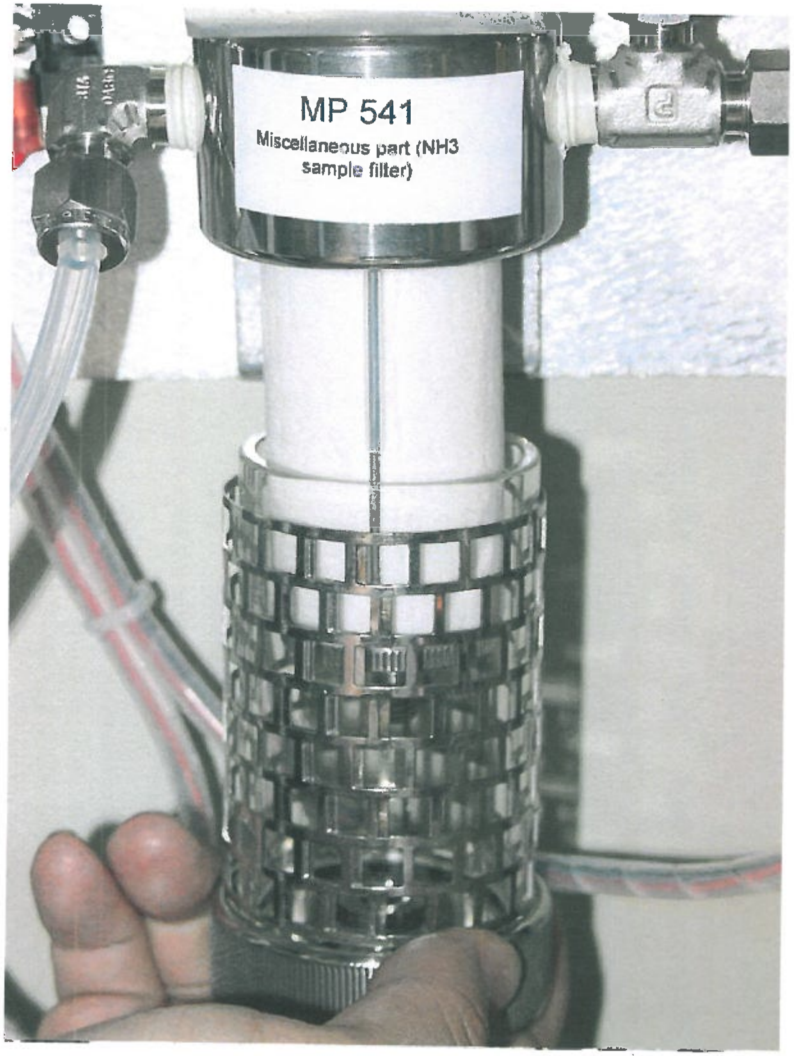


Figure 4.1

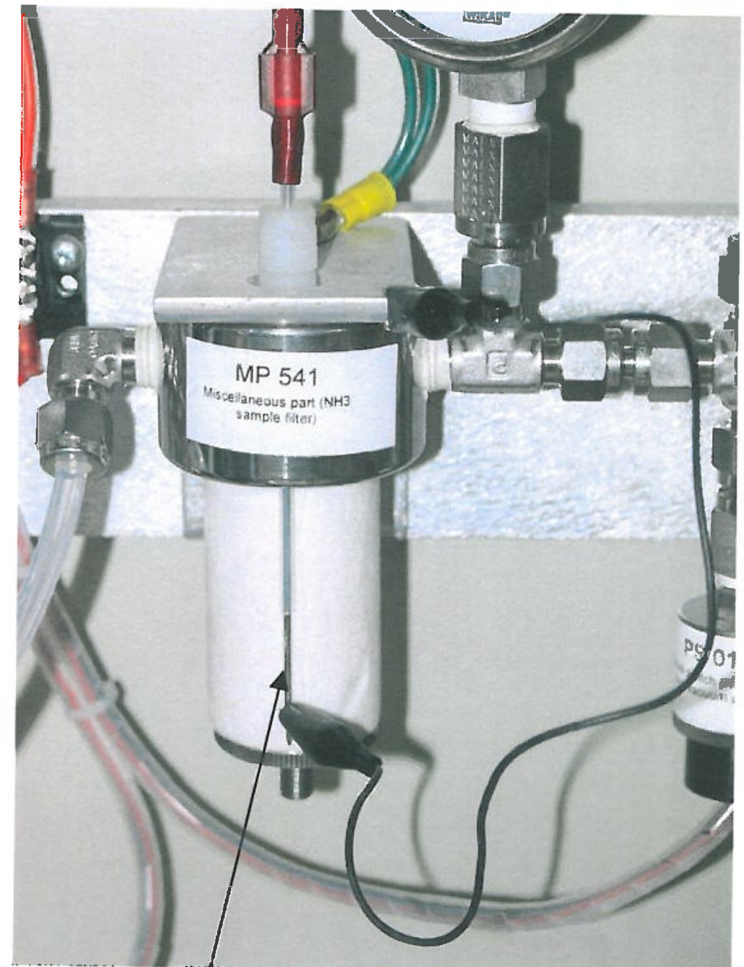


Figure 4.2

190-QC-0002-001 - Packet 190-022 - Langley Gulch Power Plant - 2008044 - Received: 12/17/2010

PERIODIC TEST PROCEDURE

TITLE: Instrument Air Pressure Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

INSTRUMENT AIR PRESSURE ALARM-DESCRIPTION

A pressure switch monitors the instrument air pressure supplied to the cabinet/shelter. The pressure switch is set to activate at approximately 70 psi (480 KPa) decreasing and is field adjustable. Activation of this alarm is indicated on the operator interface terminal.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Shut off instrument air valve (see Figure 5.1).
3) Monitor air pressure on inlet gauge mounted on the inlet air filter block, assembly.
4) Release air pressure at drain valve on the bottom of the primary air filter down to 70 psi (±5 psi), (480 KPa, ±35 KPa). Keep the sensor in alarm status for at least 60 seconds for the built-in time delay to expire.
5) Verify that the "Air Press" alarm appears on the local operator interface terminal.
6) Turn on instrument air valve and verify that "Air Press" alarm is no longer active.
7) Place CEM System back "in-service."
8) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE
(CONT'D)

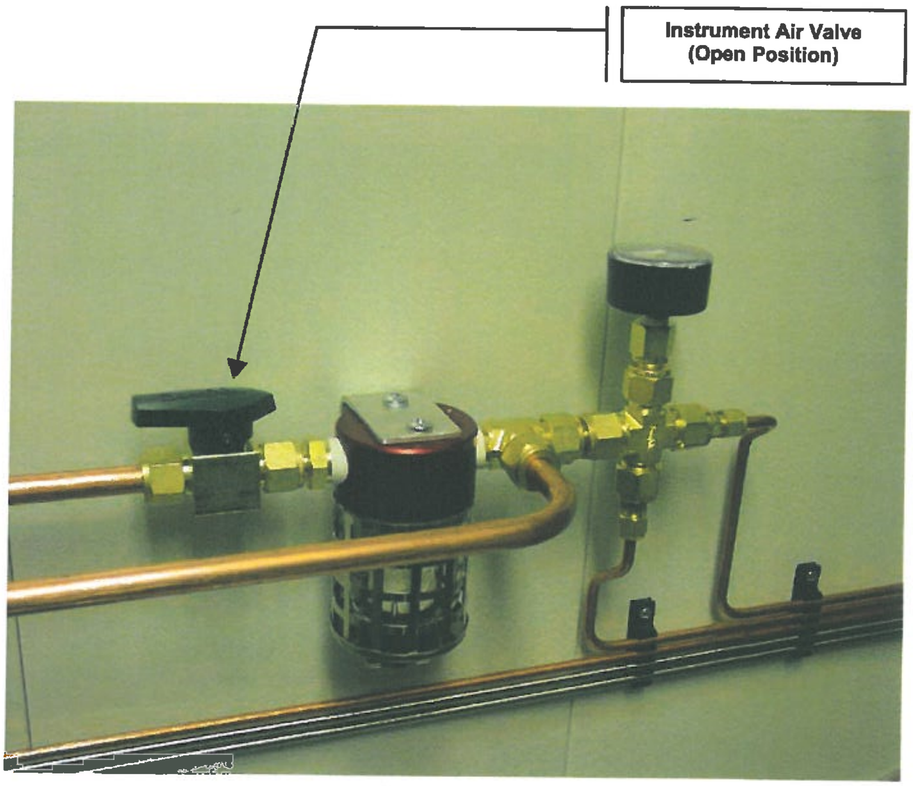


Figure 5.1

PERIODIC TEST PROCEDURE

TITLE: Heated Sample Line Temp Alarm Test (Controlled Line)

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual.

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

HEATED SAMPLE LINE TEMPERATURE ALARMS - DEVIATION VERIFICATION

A digital temperature controller maintains the sample line temperature (this device is usually mounted on the instrument rack). The controller monitors the temperature of the heated sample line via an input provided by a J-type thermocouple (T/C) imbedded in the heated sample line. The alarm is set to activate upon a predetermined deviation from the control set point temperature, refer to your manual for correct set point. If the heated sample line temperature drops 10°F below this set point or rises 15°F above the set point then the "Line Temp" alarm will be energized.

TO TEST THIS ALARM:

1) Place the CEMS in the "out-of-service" mode to prevent collection of erroneous data in the data system.

2) Go to the "default parameter" view showing the Process Temperature and Process Set Point.

Alarm High - Deviation Verification

a) Change the set point using the 'Down' arrow key until the set point is 15 or more degrees below the thermocouple reading, i.e., Process Temperature. The deviation output LED on the controller will activate and an ***Alarm High*** will be indicated.
b) Verify that the "HSL Temp" alarm appears on the operator interface terminal. Review the data system alarm log to ensure that the data system recorded the alarm.

Alarm Low - Deviation Verification

a) Change the set point using the 'Up' arrow key until the set point is 10 degrees or more above the thermocouple reading, i.e., Process Temperature. The deviation output LED on the controller will activate and an ***Alarm Low*** will be indicated.

b) Verify that the "HSL Temp" alarm appears on the operator interface terminal. Review the data system alarm log to ensure that the data system recorded the alarm.

PERIODIC TEST PROCEDURE
(CONT'D)

3) Place the CEMS back in the "in-service" mode to re-establish valid data collection in the data system.

4) Record the completion of this procedure in the CEMS Log Book and the QA Manual checklist.

Note: This test just gives an indication that the circuit and controller are functioning. For sample lines greater than 200 feet (60 meters), there may be an additional T/C. To test the secondary T/C, disconnect the primary T/C at the connector located near the sample line, and then connect the secondary going to the temperature controller. Repeat the steps above.

PERIODIC TEST PROCEDURE

TITLE: Sample Flow Alarm Test

MAINTENANCE FREQUENCY: Refer to the Summarized Maintenance Schedule in the O&M Manual

ESTIMATED TIME / PERSONS REQUIRED: 5 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

SAMPLE FLOW ALARM-DESCRIPTION

Each sample flow meter can be equipped with an optional sample flow switch. If the sample flow drops below the preset level, the switch contacts will close indicating the fault condition. The "Sample Flow" alarm will activate on the local operator interface terminal if this alarm is detected. These flow switches are field adjustable and should be set to alarm at approximately 50 to 75% of the normal sample flow rate. Since most analyzers are flow sensitive, this alarm prevents accumulating erroneous data due to low or nonexistent sample flow.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Note the setting on the analyzer flow meter.
3) Decrease the flow with the flow control valve until the "Sample Flow" alarm is activated on the local operator interface terminal.
4) Return the flow meter to its original setting and verify that the "Sample Flow" alarm is no longer active.
5) Place the CEM System back "in-service".
6) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm.
7) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE

TITLE: Calibration Gas Flow Alarm Test

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: None

CALIBRATION GAS FLOW ALARM-DESCRIPTION

If the calibration gas flow drops below the preset level, the switch contacts will close indicating the fault condition. The "CAL FLOW" alarm will be activated on the operator panel in the shelter if a low flow condition is detected. The flow switch is field adjustable and should be set to deactivate on decreasing flow at about 50 to 75% of the normal calibration gas flow rate through the sample probe. This switch will probably deactivate during a calibration at cabinet due to reduced flow requirements.

TO TEST THIS ALARM:

1) Initiate the "out-of-service" mode to prevent collection of erroneous data in the DARS/DAHS, and indicate maintenance.
2) Open a test gas valve using the functions in the local operator interface terminal. Make sure that the Cal-at Cabinet valve is in the Probe position. Wait 15 seconds for flow to stabilize. Note level of the calibration gas flow. Flow rate should be equal to the sum of all the sample flow rates to each analyzer plus the bypass flow rate plus 1 to 2 LPM. The "Cal Flow" alarm should not be activated.
3) Decrease the calibration gas flow rate slowly by adjusting the flow valve on the calibration gas flow meter until the PLC Digital Input deactivates. Note level of flow on flow meter.
   Keep the sensor in this state for 15 seconds, to allow the PLC time delay to expire.
4) If the flow rate at which the Input deactivated was about 50 to 75% of the calculated calibration gas flow rate, proceed to step 6. If the flow rate at which the Input was deactivated was not 50 to 75%, the flow switch may require adjustment. Follow directions in step 5.
5) To adjust the calibration flow switch, turn the adjustment screw on the body of the flow switch clockwise to increase the flow rate level at which the alarm is activated or turn the adjustment screw counter clockwise to decrease the flow rate at which the alarm is activated. Increase the flow until the PLC Input activates and then repeat steps 1 through 4 above until the Input is deactivated at the correct flow rate (see Figure 12.1)
6) Reset the calibration flow meter to the correct flow rate.
7) Turn off the gas valve and place the CEM System back "in-service."
8) Review the DAHS alarm log to ensure that the DARS/DAHS recorded the alarm
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PERIODIC TEST PROCEDURE
(CONT'D)

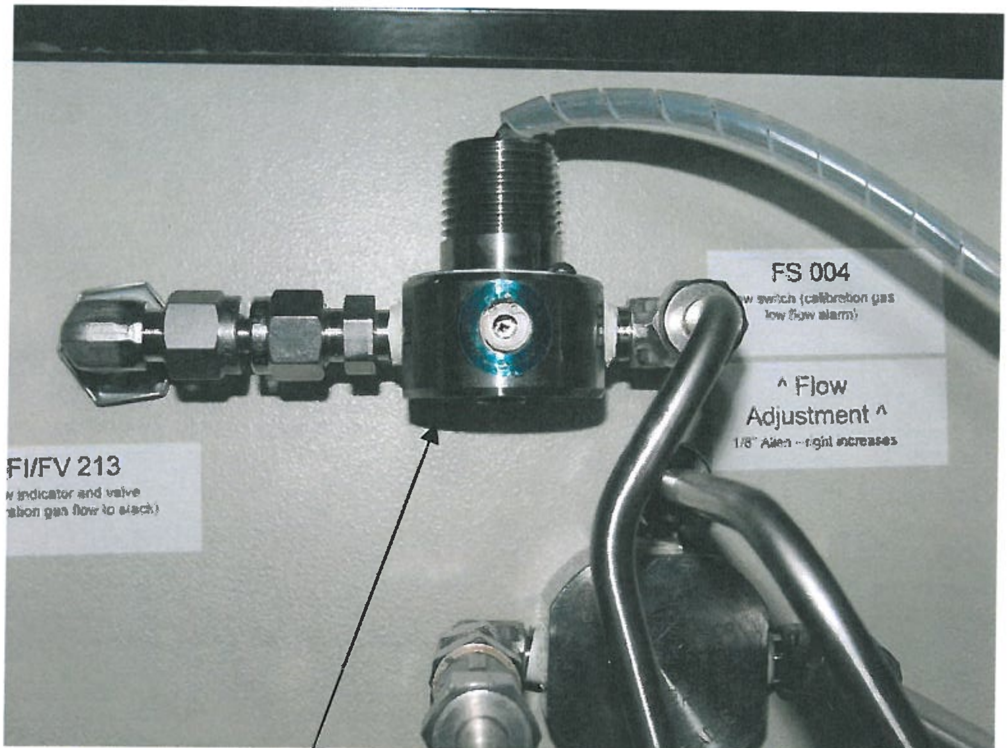


Figure 12.1

APPENDIX 4

PREVENTATIVE MAINTENANCE PROCEDURES

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Change Fine Sample Filters

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 10" adjustable wrench and miscellaneous hand tools

Note: This PMP should be done in conjunction with PMP #12 when in accordance with the Maintenance Schedule.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

The fine sample filter will remove 99.9% of all particulates 0.1 micron or larger. Its purpose is to protect the downstream components, especially the membrane dryer, from particulate contamination.

1) Place the CEM System in "out-of-service" mode.
2) Turn off sample pump(s) by using circuit breaker or by pulling the power plug.
3) Remove the knurled lower flange and glass cylinder for each filter.
4) Remove internal knurled nut and filter.
5) Install new filter. Make sure the water alarm probe is resting against the filter without touching the knurled nut.
6) Reassemble the unit taking care that the o-rings are well in place. Be very careful when tightening the assembly. Excessive tightening can break glass filter cylinder.
7) Turn on the sample pump.
8) Perform system leak test using PMP #21.
9) Once the assembly is complete, place the CEM System "back-in-service".
10) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Exercise Flowmeter

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: N/A

MAINTENANCE INSTRUCTIONS:

Check for ability to vary flow rates for each flowmeter.

1) Place the CEM System in "out-of-service" mode.
2) Each flowmeter is adjustable. Adjustment is obtained either with a valve on the flowmeter or by a separate valve in series with the flowmeter. Identify each flow meter that will be tested during this procedure.
3) Note and record the setting of each flowmeter.
4) Turn flow control knob on each flowmeter (on flowmeters with knob on base) clockwise then counter clockwise, then back to original setting. The rotometer float should move accordingly.
5) On flowmeters without flow control knobs, (i.e., Siemens analyzer and bypass flow control meters) find the corresponding flow control knob and turn clockwise, then counter clockwise, then back to the original setting. The rotometer float should move accordingly.
6) On calibration gas flowmeter, activate the zero or span solenoids using the local operator interface terminal. Vary flow then reset to original setting recorded in 3 above.
7) Check the flowmeter settings. A marker should be present on the flowmeter to indicate its proper setting. The valve of this setting should match the recommended valve listed in the O&M Manual. Settings may also appear in the Shelter's Log Book.
8) Place the CEM System "back-in-service".
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Exercise Pressure Regulator

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: N/A

MAINTENANCE INSTRUCTIONS:

1) Each regulator is manually adjustable and has a corresponding gauge to indicate the regulator control setting. Identify each regulator that will be maintained during this procedure.

2) Note settings on gauges associated with each regulator and record.

3) Turn regulator control knobs clockwise then counter clockwise, then return to original settings on all sample, bypass and purge air regulators as recorded in step 2 above.

4) Flow must exist through all regulators. To test calibration gas regulators, activate zero and span solenoids using the local operator interface terminal. Exercise, adjust and set pressure while cal gases are flowing.

5) Check the regulator settings. A marker should be present on each regulator to indicate its proper setting. The value indicated by the marker should match the value recommended in the O&M Manual, or as recorded in the Shelter's Log Book.

6) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Primary and Secondary Instrument Air Filters

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: ½ hour, 1 person

TOOLS / MATERIAL REQUIRED: primary and secondary air filter, 8" crescent wrench.
Note: Refer to the Recommended Spare Parts List located in the Appendix of the O&M Manual for part numbers per system. Some systems do not include a secondary filter.

Safety Notes: Safety Glasses

CAUTION! ***Bleed off all instrument air prior to changing filters.***

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.
2) Shut off instrument air valve in cabinet/shelter.
3) Release instrument air pressure using drain valve on the primary air filter. Check instrument air pressure gauge for 0 psi (0 KPa).
4) Remove primary and secondary air filter housings. The secondary filter polycarbonate bowl unscrews from the bottom. The primary filter drain nut unscrews from the bottom to free the polycarbonate housing. Be careful to retain o-ring.
5) Inspect filter seals. Replace if seals show signs of wear or deformity.
6) Remove air filters and install new filters.
7) Reinstall filter housings. Make sure that the screws and o-ring are still in place.
8) Turn instrument air valve back on.
9) Check filter housings for leaks using leak detection fluid.
10) Place CEM System "back-in-service".
11) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Clean Heated Sample Line

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 2 persons

TOOLS / MATERIAL REQUIRED: 6" adjustable wrench, 8" adjustable wrench and service water. Utility gloves.

Safety Notes: Safety Glasses and Gloves

MAINTENANCE INSTRUCTIONS:

The sample line connecting the sample probe to the cabinet/shelter is heated to prevent the sample from dropping below its dew point. It contains a 5/16" and a 3/8" OD tube for a dual sample line and a 5/16" OD tube for a single sample line. The tubes are covered with ½" of insulation to form a line of about 1-¾" diameter. The heater is a series, self-limiting heater that will automatically reduce its power requirements as it approaches its design temperature. The line is designed to maintain a minimum sample gas temperature of 350°F (177°C) when ammonia is present in the sample or 250°F (121°C) when ammonia is not present.

TO CLEAN HEATED SAMPLE LINE:

1) Place the CEM System in "out-of-service" mode.
2) Switch "off" heated sample line circuit breaker and allow line to cool.
3) Turn off the sample pump at the breaker or by pulling the power plug.
4) Disconnect heated sample line at both ends.
5) Connect instrument air to the end of the heated sample line in the cabinet/shelter and turn air on for 5 minutes.
6) Connect clean service water to a line at the bottom and run for 5 minutes. Monitor the condition of the water at the probe end and ensure that it is clean.
7) Shut off water, disconnect the water line from the heated sample line and allow water to drain for approximately 10 minutes.
8) Connect instrument air back onto the heated sample line at the cabinet/shelter end and turn the air on for 10 minutes.
9) Switch "on" heated sample line circuit breaker.
10) Continue the flow of instrument air through the heated sample line for an additional 15 minutes or until HSL temperature is normal.
11) Using gloves connect the line back to the probe and cooler.
12) Turn on the sample pump.
13) Perform System Leak Test using PMP #21.
14) Place the CEM System "back-in-service".
15) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

Note: If the heated sample line is still not clean, consult CiSCO.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Air Conditioner Filters on HVAC

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: Air Filter, miscellaneous hand tools.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

1) To access the filters, remove the HVAC exterior panel that contains the variable intake damper (Reference HVAC manufacturers manual for details, Appendix J).

2 Remove the AC fresh air and return air filters.

3) Inspect both filters for dirt build-up and condition.

4) A dirty fresh air filter or return air filter must be replaced.

5) Install existing or new filters as required and replace the HVAC exterior panel.

6) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Change Membrane Dryer

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: 9/16 open-end wrench, membrane tube bundle, pressure gauge and a on/off valve and screw driver.

Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers per system.

To minimize maintenance downtime, it may be advisable to have a spare membrane dryer/housing assembly on site. The spare assembly can be installed and the replaced assembly can be rebuilt as time permits.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

Membrane Dryer

A membrane dryer is used to remove additional moisture from the sample to prevent acid mist carryover and further reduce any analysis interference due to water. The sample gas moisture is removed from the sample gas in the gas phase using dry air input provided by the heatless air dryer. A sample dew point of -80°F (-62°C) is achieved

The material used in the membrane dryer allows water, in the gas phase, to permeate through the membrane from the wet sample side to the dry purge side due to a difference in water vapor pressures. Dry purge air with an -80°F (-62°C) dew point is supplied by the instrument air dryer. Purge airflow should be higher than sample flow to assure sufficient drying capacity.

TO CHANGE MEMBRANE DRYER:

1) Place the CEM System in "out-of-service" mode.
2) Unplug the sample pump power cord.
3) Remove membrane dryer assembly and all tubing connections.
4) Remove the end cap at each end of membrane assembly and remove o-rings.
5) Loosen both black lock bushings on air purge housing and remove old tube bundle.
6) Inspect o-rings and replace if necessary.
7) Install new tube bundle and reassemble membrane assembly. Make sure the tube bundle o-ring seals are installed.
8) Leak check membrane dryer assembly. This can be accomplished by installing a pressure gauge with an on/off valve on the inlet of the membrane dryer and plugging the outlet. Pressurize the dryer to 15 psi (103 KPa), shut off the valve, and monitor the pressure. If the pressure holds for 5 minutes, the dryer is leak tight.
9) Install membrane dryer assembly back into the system and tighten the tubing connections.
10) Plug in sample pump power cord.
11) Place the CEM System "back-in-service".
12) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Air Dryer Towers

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 15 minutes, 1 person

TOOLS / MATERIAL REQUIRED: small strap wrench or channel locks

Safety Notes: Safety Glasses

***CAUTION!* Bleed off all instrument air prior to changing towers out.**

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.
2) Shut off instrument air valve in cabinet/shelter.
3) Release instrument air pressure using drain on primary air filter. Check the instrument air gauge for 0 psi (0 KPa).
4) Remove air dryer towers using a strap wrench.
5) Install new air dryer towers. Tighten towers only hand tight.
6) Turn instrument air valve on.
7) Leak check the dryer with leak detector fluid.
8) Place CEM System "back-in-service".
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Drain Pump Tubing

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: Tubing cutter, replacement tubing
Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers per system.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

Condensate removed from the sample cooler will contain Nitric and Sulfuric acids, which may corrode the flex tubes.

1) Place the CEM System in "out-of-service" mode.
2) Unplug drain pump power cord.
3) Remove tubing from refrigeration unit trap drain fitting and from drain vent manifold.
4) Remove four (4) wing nuts on multiple head pumps or four (4) knurled screws on a single head pump.
5) Separate pump head in half and remove tubing.
6) Reinstall new section of tubing in pump head.
7) Put head(s) back together on the pump.
8) Reattach tubing on the drain/vent manifold and refrigeration trap drain fitting. The pump motor turns clockwise when viewed from the pump head end. The tube on the right goes to the refrigerated cooler.
9) Plug in the drain pump power cord.
10 Perform system leak check using PMP #21.
11) Place the CEM System "back-in-service".
12) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Fine Sample Filter Glass Cylinder Seal

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 6" adjustable wrench, filter gasket
Note: This PMP should be done in conjunction with PMP #1.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.
2) Turn off the sample pump at the breaker or by pulling the power plug.
3) Remove fine sample filter base with wrench. Be careful not to break filter glass cylinder.
4) Replace filter cylinder gaskets.
5) Reassemble filter unit insuring proper installation of gasket. Be careful not to over tighten the glass cylinder as it could break.
6) Turn on the sample pump.
7) Perform System Leak Test using PMP #21.
8) Place the CEM System "back-in-service".
9) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Sample Pump Head Rebuild (1 or 2 heads)

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: 5/32" and 3/16" Allen head wrench, 9/16" open-end wrench, vacuum gauge with ¼" male npt. fitting, rebuild kit for single head pumps, or dual head pump.

Note: Stack sample pump and bypass stack pumps use—refer to the Recommended Spare Parts List in the O&M Manual for part numbers.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

1) Place the CEM System in "out-of-service" mode.
2) Note direction of flow on pump head. Label in and out lines.
3) Remove pump from system by pulling power cord and removing ¼" flex lines using 9/16" wrench.
4) Remove 4 pump head screws using 3/16" Allen head wrench.
5) Remove pump diaphragm plate using 5/16" Allen head wrench.
6) Remove and then replace Teflon coated diaphragm and small Teflon seal from kit.
7) Wipe any foreign particles from inside pump head area.
8) Remove valve plate by removing two (2) screws using 5/16" Allen head wrench.
9) Remove then replace 2-flapper valves and valve gasket from kit.
10) Reinstall valve plate onto head (note plate is keyed). Ensure valve disks are seated and do not pinch during assembly.
11) Reinstall head on pump in accordance with the direction labeled in Step 2.
12) Start up pump and check deadhead vacuum by attaching a vacuum gauge onto the inlet (vacuum range should be 18-22" hg depending on altitude).
13) Reinstall pump into system.
14) Check sample and bypass flows to see if they are in specs per O&M Manual or Log Book entry.
15) Perform System Leak Test using PMP #21.
16) Place the CEM System "back-in-service".
17) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Replace Probe Filter and Gasket Set on High Temperature Probe Assembly

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 1 hour, 1 person

TOOLS / MATERIAL REQUIRED: 6" adjustable wrench, $^{3}/_{16}$" Allen wrench, inlet sample probe filter element, gasket set, gasket scraper.

Note: Refer to the Recommended Spare Parts List or Probe Assembly drawings located in the Appendix of the O&M Manual for part numbers per system.

Safety Notes: Safety Glasses and Gloves

MAINTENANCE INSTRUCTIONS:

1) Make sure the probe is cool enough to work on (Unit not on-line).
2) Place CEMS in "Out-of-Service" mode.
3) Turn off the sample pump at the breaker.

At the Probe:

4) Loosen and remove two (2) socket cap screws from the bottom of the probe manifold. (Use $^{3}/_{16}$" Allen wrench.)
5) Loosen four (4) captive hex head screws and remove cover assembly. (Use 6" adjustable wrench.)
6) Remove outer gasket, filter element and inner gasket. Also remove the three (3) O-Ring manifold gaskets. Clean filter seat surfaces with gasket scraper and rag.
7) Install new inner gasket, filter element and outer gasket. Also install the three (3) new O-Ring (manifold) gaskets. (The three (3) O-Rings (manifold) gaskets are provided with the gasket set.)
8) Replace probe cover and securely and evenly tighten the four (4) captive hex head screws. (DO NOT over-tighten.) Ensure gasket o-rings are seated properly before tightening.
9) Replace socket cap screws (bottom of manifold) and securely tighten. (DO NOT over-tighten.)

Inside the Shelter:

10) Turn on the sample pump.
11) Perform the system leak test using PMP #21.
12) Place the CEMS "back-in-service".
13) Record the completion of this procedure in the CEMS Log Book and the QA Manual checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: TEI NO_x Analyzer Pump Rebuild

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 20 minutes, 1 person

TOOLS / MATERIAL REQUIRED: Pump repair kit (part no. 5013) Allen wrench – 3mm, 4mm, 9/16" wrench, spanner wrench

Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers.

MAINTENANCE INSTRUCTIONS:

TO REBUILD PUMP:

1) Place CEMS "out-of-service".
2) Disconnect pump tubing.
3) Remove the eight (8) socket head screws and washers holding the top metal plate of the pump head (use a 3mm Allen wrench). Refer to Figure 1.

   IMPORTANT: Note the orientation of the plate for reassembly later on.
4) Remove and discard old Teflon gasket.
5) Remove main body of pump head by removing four (4) socket head screws (use 4mm Allen wrench).

   IMPORTANT: Note the correct orientation of the head so as to reassemble it correctly.
6) To remove Teflon diaphragm, loosen and remove the clamping disk by using the spanner wrench in the dimples of the claming disk.
7) Discard the old Teflon diaphragm.
8) Insert clamping disk into new Teflon diaphragm (consisting of three (3) pieces) and screw clamping disk back into pump head. Do not over-tighten.
9) To remove flapper valve(s), loosen and remove screw and nut holding the flapper valves in place. Replace the old flapper with the new flapper being sure that the flappers are lying completely flat and straight. Be sure the screw head and not the washer is on the smooth side of the pump head.
10) Replace main body of the pump with four socket head screws being sure to use correct orientation as noted in Step 5.
11) Place Teflon gasket over main body of the pump head. There is only one position that this gasket can be placed so that all eight screw holes in the pump headline up with the holes in the gasket.
12) Replace top plate of pump head with the eight (8) socket head screws and washers being sure the Teflon gasket stays in place.
13) Reattach tubing.
14) Start pump and check vacuum pressure by reading the valve in the service mode menu of the analyzer. Valve should be below 35 mmHg.
15) Place system "in-service" and record completion in System Log Book.

PREVENTATIVE MAINTENANCE PROCEDURE (CONT'D)

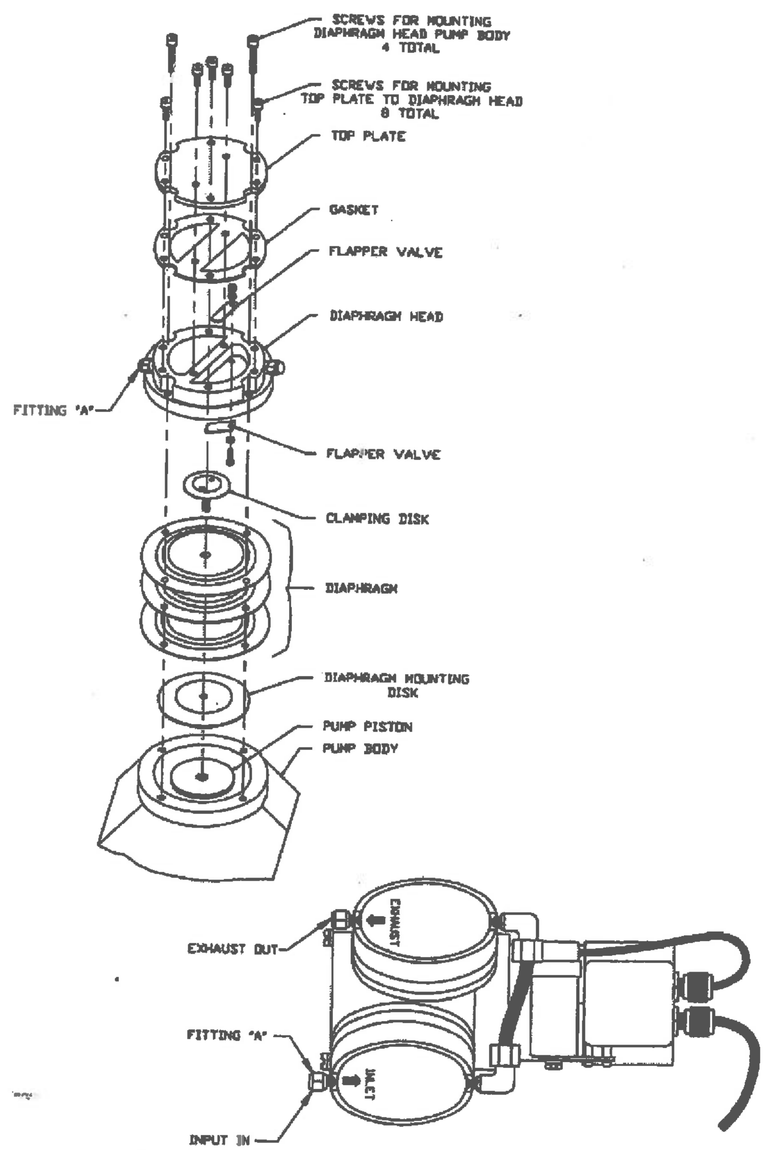


Figure 1 – KNF Pump Assembly

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: System Leak Test Procedure

MAINTENANCE FREQUENCY: See O&M, QA Manuals and Referenced PMPs

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 2 10" crescent wrenches or wrench set

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

System Leak Test

The System Leak Test is conducted to ensure that there are no leaks in the system that might impact the integrity of the sample and the sample analysis. This procedure tests for leaks in the vacuum portion of the CEMS. Leaks downstream of the vacuum pump are in a positive pressure environment and will not normally impact sample integrity, but could impact the ability to get an adequate sample volume and/or pressure.

1) Place the system in the "out-of-service" mode.
2) Select the zero gas by selecting it from the "Test Gas" screen on the OIT Panel.
3) Place the 4-way calibration valve in the "cabinet" position.
4) Allow the system to stabilize. Typically 3-4 minutes is adequate.
5) Adjust the oxygen analyzer to a zero value.
6) Place the 4-way calibration valve in the "probe" position.
7) Allow the system to stabilize. Typically 4-5 minutes is adequate.
8) Look at the oxygen analyzer output, a reading greater than 0.20 indicates an unacceptable leak. The leak can be anywhere from the probe through the vacuum pump inlet. All fittings and parts should be checked for tightness and tubing needs to be checked for leakage.
9) Once the assembly is complete, place the CEM System "back-in-service".
10) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.

PREVENTATIVE MAINTENANCE PROCEDURE

TITLE: Change NH_3 Scrubber

MAINTENANCE FREQUENCY: See O&M and QA Manuals

ESTIMATED TIME / PERSONS REQUIRED: 30 minutes, 1 person

TOOLS / MATERIAL REQUIRED: 9/16" open-end wrench, 7/16" open-end wrench or 10" adjustable wrench, Teflon tape, and replacement scrubber.
Note: Refer to the Recommended Spare Parts List in the O&M Manual for part numbers.

Safety Notes: Safety Glasses

MAINTENANCE INSTRUCTIONS:

NH_3 Scrubber:

An NH_3 (ammonia) scrubber is installed inline on the sample inlet prior to a NO_x analyzer in a CEM System on a process, which utilizes NH_3 to reduce NO_x emissions.

TO CHANGE NH_3 SCRUBBER

1) Place the CEM System in "Out-of-Service" mode.
2) Loosen and remove the compression fittings (connected to tubing) from each end of the NH_3 scrubber housing.
3) Loosen and remove (Teflon taped) threaded fittings from each end of the NH_3 scrubber housing.
   Note: Take note that the NH_3 scrubber housing is marked with a "direction of flow arrow" which points towards the analyzer.
4) Remove old Teflon tape from housing fitting threads and replace with new Teflon tape.
   Note: Teflon tape threads that are inserted into the NH_3 scrubber (apply clockwise going with the threads) — the threads that insert into the compression fittings (on the tubes) do ***not*** get Teflon taped.
5) Install NH_3 scrubber housing fittings to the appropriate end of the ***new*** NH_3 scrubber housing.
   Note: Refer to the "direction of flow arrow" note.
6) Securely tighten the ***new*** NH_3 scrubber housing fittings to the compression fittings.
7) Once the assembly is complete, place the CEM System "Back-in-Service".
8) Record completion of this procedure in the CEM System Log Book and the QA Manual Checklist.