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

Draft for Facility Review

DRAFT XX, 2013
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The purpose of this Statement of Basis is to set forth the legal and factual basis for the Tier I operating permit terms and conditions, including references to the applicable statutory or regulatory provisions for the terms and conditions, as required by IDAPA 58.01.01.362

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1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
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
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
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million 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
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/or 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 draft 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 (permit conditions) that apply facility-wide. Where required, monitoring, recordkeeping and reporting requirements sufficient to assure compliance with each permit condition follows the 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 applicable requirement immediately follow the applicable requirement.

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).

3. FACILITY INFORMATION

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
Month XX, 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
Month XX, 2013	T1-2013.0017 PROJ 61165	Initial Tier I	Initial Title V Operating Permit.	A

4. APPLICATION SCOPE AND 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 4.1 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 (2012AAI772) that initial startup of the combustion turbine occurred on April 11, 2012.
June 10, 2012	DEQ received the O&M manual (2012AAI1383).
March 11, 2013	DEQ received a Tier I permit application (2013AAG289), which included revisions to equipment information and the emissions inventory.
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 (2013AAG453), which included a preliminary applicability analysis concerning equipment vendor changes, and provided a schedule for submitting the remaining information requested in the incompleteness letter.
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 (2013AAG702), 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.
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 (2013AAG1038), including an ambient air quality compliance demonstration.
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 XX, 2013	DEQ made available the revised draft PTC and supporting documents for applicant review (2013AAG712[v2], 2013AAG711[v2]).
July XX, 2013	DEQ issued the final PTC permit.
July XX, 2013	DEQ made available the draft Tier I and supporting documents for applicant review (2013AAG297[v1], 2013AAG296[v1]).
July XX, 2013	DEQ determined that the PTC application was complete (2013AAG295), and could be incorporated into the Tier I permit.
August XX, 2013	DEQ published notification of the public comment period on the proposed action [XXX].
August XX, 2013	DEQ provided notification of the public comment period on the proposed action to EPA, FLM, affected states, and interested parties [XXX].
August XX – August XX, 2013	DEQ provided a public comment period on the proposed Tier I action.
August XX, 2013	DEQ provided the proposed permit and statement of basis to EPA (2013AAG297[v2], 2013AAG296[v2]) for review.

5. EMISSIONS UNITS AND EMISSION INVENTORIES

5.1 Emissions Units and Control Equipment

Table 5.1 lists the emissions units and control equipment associated with the Idaho Power Company - Langley Gulch Power Plant.

Table 5.1 Emissions Units, Control Device, and Discharge Point Information

Source Description		Control Equipment Description
Combustion turbine and duct burner (CT1)		
Combustion turbine (CT)		
Manufacturer:	Siemens	
Model:	SGT6-5000F	
Configuration:	1x1 combined cycle	
Manufacture date:	2010	
Nominal output:	269 MW	Dry low NO_x combustors
Maximum capacity:	2,134 MMBtu/hr [(a)]	Selective catalytic reduction system
Fuel:	natural gas	Catalytic oxidation system
Fuel consumption:	2,146,600 scf/hr	Good combustion practices
	793.1 MM lb/yr [(b)]	
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)	EPA Tier 2 technologies
	2.25 L/cylinder	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)	EPA Tier 3 technologies
	1.48 L/cylinder	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	
Manufacture date:	2010	Drift eliminators
Maximum water flow:	76,151 gpm	Good operating practices
Maximum operation:	8,760 hr/yr	
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 0ºF.
b) Combined fuel usage of the CT and duct burner.
c) For maintenance and testing activities.

5.2 Insignificant Emissions Units Based on Size or Production Rate

No emissions unit or activity 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.

5.3 Emission Inventories

Table 5.2 and Table 5.3 summarize the emissions inventory 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 emission is state or federally enforceable. The use of the control equipment, fuels, and operational schedules listed in Table 5.1 were used in the development of the emission inventories. Refer to Appendix B – Emission Inventories for the emission estimates provided in the application.

Table 5.2 Potential to Emit Criteria Pollutants [a]

Emissions Units	NO_x lb/hr	NO_x T/yr[d]	CO lb/hr	CO T/yr[d]	VOC lb/hr	VOC T/yr[d]	$PM_{2.5}$[b]/PM_{10}[c] lb/hr	$PM_{2.5}$[b]/PM_{10}[c] T/yr[d]	SO_2 lb/hr	SO_2 T/yr[d]	Pb lb/hr	Pb T/yr[d]	GHG CO_2e 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
CT and duct burner[e] LL[g]	452.78		70.35		18.91								
CT and duct burner[e] 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 on hours of operation. 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.
h) At startup or shutdown 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 5.3 Potential to Emit Hazardous Air Pollutants and Toxic Air Pollutants

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

a) Uncontrolled average emission rate in pounds per hour is the maximum estimated hourly average.
b) Controlled average emission rate in pounds per hour is an annual average, based on the proposed annual operating schedule and annual limits.
c) Non-carcinogenic substance listed in IDAPA 58.01.01.585.
d) Carcinogenic substance listed in IDAPA 58.01.01.586.
e) Tons per consecutive 12-calendar-month period.
f) 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.

6. EMISSION LIMITS AND MRRR

This section contains the applicable requirements for this major facility. Where applicable, monitoring, recordkeeping and reporting requirements (MRRR) follow the applicable requirement and state how compliance with the applicable requirement 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. The subsequent subsections list the applicable requirements for specific emissions units and pollutant-emitting activities. The final subsections identify insignificant activities, address applicable acid rain program requirements, and contain general provisions applicable to all major facilities subject to Tier I operating permit requirements.

MRRR

Immediately following each applicable requirement (permit condition) is the periodic monitoring regime upon which compliance with the underlying applicable requirement is demonstrated. A periodic monitoring regime consists of monitoring, recordkeeping and reporting requirements for each applicable requirement. If an applicable requirement does not include sufficient monitoring, recordkeeping and reporting to satisfy IDAPA 58.01.01.322.06, 07, and 08, then the permit must establish adequate monitoring, recordkeeping and reporting sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit 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 may also be required.

State Enforceability

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

Federal Enforceability

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

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

Section 1 – Acronyms, Units, and Chemical Nomenclature

This permit section describes the acronyms used in this permit.

Section 2 – Permit Scope

Permit Conditions 2.1 – 2.2

These permit conditions describe for this permit its purpose, the underlying permits incorporated, and the emission sources and the control equipment regulated.

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 monthly.
- 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 3.9 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 monthly.
- 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 Conditions 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 6.2).
- Monitor cooling water solids content and flow rate (Permit Conditions 6.4 and 6.5).

- Use of bin vent filters (Permit Condition 7.2).

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

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 limit 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 through 4.4), BACT work practices (Permit Conditions 4.12, 5.7, 6.3, and 7.3), the ammonia injection flow rate limit (Permit Condition 4.19), and manufacturer's specifications (Permit Conditions 5.6 and 5.8). Copies of current 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 CEMS monitoring (Permit Conditions 4.21 – 4.29, 4.37 – 4.38, 9.2 – 9.4, 9.8 – 9.9, and 9.12) or during testing (Permit Conditions 3.8, 4.33 – 4.35, and 5.14).
- Take appropriate action to correct, reduce, and minimize emissions from excess emissions events.
- Prohibit excess emissions during any DEQ Atmospheric Stagnation Advisory or Wood Stove Curtailment Advisory.

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

[2] "Tier I Permit Application Supplemental Information," Idaho Power, April 30, 2013 (2013AAG700).

- Notify DEQ of each excess emissions event as soon as possible, including information regarding each upset, breakdown, and safety event.
- Report excess emissions events.
- 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 4.33 – 4.34, and 3.23 – 3.26):

- 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 explicit requirements 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

This section establishes requirements for the combustion turbine and duct burner emissions units. A description of the process, control devices, and

Permit Conditions 4.1 and 4.20

Permit Condition 4.1 defines startup and shutdown (SU/SD) events and low-load (LL) 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 effectively limited by the annual NO_x and CO emission limits (Permit Condition 4.5) and the annual fuel usage limit (Permit Condition 4.17).

MRRR include the following:

- Monitor and record startup and shutdown (SU/SD) events and low-load (LL) events (Permit Condition 4.20).

Permit Condition 4.2 – 4.4, 4.10 – 4.12, 4.13 – 4.14, 4.20 – 4.22, 4.26 – 4.27, 4.33 – 4.34

Permit Conditions 4.2 – 4.4 establish BACT emission limits for the CT and the duct burner (combined). Refer to the PSD Classification (40 CFR 52.21) section for additional information concerning PSD BACT determinations. Copies of current monitoring plans and protocols are provided in Appendix E – Monitoring Plans & Protocols.[2]

MRRR include the following:

- Install, operate, and maintain SCR and CatOx control equipment (Permit Conditions 4.10 – 4.12).
- 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 3.14 – 3.16).
- Comply with monitoring protocols and methodologies (Permit Conditions 4.21 and 4.26).
- Perform compliance testing (Permit Conditions 4.33 – 4.34, and 3.23 – 3.26).

Permit Condition 4.5, 4.10 – 4.12, 4.13 – 4.14, 4.20 – 4.22, 4.26 – 4.27

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. Copies of current monitoring plans and protocols are provided in Appendix E – Monitoring Plans & Protocols.[2]

MRRR include the following:

- Install, operate, and maintain SCR and CatOx control equipment (Permit Conditions 4.10 – 4.12).
- 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 3.14 – 3.16).
- Comply with monitoring protocols and methodologies (Permit Condition 4.21 and 4.26).

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.

MRRR include the following:

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

Permit Condition 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 for ammonia injection flow rate monitoring (Permit Conditions 3.14 – 3.16).
- Comply with monitoring protocols and methodologies (Permit Condition 4.32).
- 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.

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] Copies of current monitoring plans and protocols are provided in Appendix E – Monitoring Plans & Protocols.[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 3.24).

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. Refer to the PSD Classification (40 CFR 52.21) section for additional information concerning PSD BACT determinations.

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 – 5.10, 5.13, and 5.14).
- Comply with O&M manual requirements for minimizing emissions (Permit Conditions 3.14 – 3.16).

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. 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 5.11 – 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. Refer to the PSD Classification (40 CFR 52.21) section for additional information concerning PSD BACT determinations. These limits correspond to the potential emission rates (PTE) used in preconstruction modeling compliance demonstrations.

Permit Condition 5.13

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

Permit Condition 5.14

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. Refer to the PSD Classification (40 CFR 52.21) section for additional information concerning PSD BACT determinations.

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

MRRR include the following:

- Comply with manufacturer's recommendations and O&M manual requirements (Permit Conditions 6.1, 6.3, and 3.14 – 3.16).
- Operate the control equipment (Permit Condition 6.2).
- Monitor cooling water solids content and flow rate (Permit Conditions 6.4 and 6.5).

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. Refer to the PSD Classification (40 CFR 52.21) section for additional information concerning PSD BACT determinations.

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

MRRR include the following:

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

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 Conditions

Permit Condition 9.1

This permit condition describes the statement of basis for Acid Rain permit requirements. Refer to the Acid Rain Permit (40 CFR 72-75) section for information concerning Acid Rain Program regulatory review and MRRR.

Permit Conditions 9.2 – 9.4

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.b 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 9.5

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 9.6 – 9.7

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 9.8 – 9.19

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 9.20 – 9.21

This permit condition 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

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.

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”.
- Permit conditions specified as “state-only” 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 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 program 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.

7. REGULATORY REVIEW

7.1 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 (AQCR) 63. There are no Class I areas within 10 kilometers of the proposed facility. Refer to 40 CFR 81.313 for additional information.

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

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

Because the proposed 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 And Chronology section for a listing of relevant dates.

7.3 PSD Classification (40 CFR 52.21)

Because the proposed facility is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input (designated facility) which has the potential to emit 100 tons per year or more of CO (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 proposed 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.

7.4 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]

The CT, HRSG, and duct burner are affected sources subject to Subpart KKKK, because the construction date was after February 18, 2005.

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 June 12, 2006.

In accordance with 40 CFR 60.4200(a)(2)(i), 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 5.1 for the manufacture dates of each emissions unit.

7.5 NESHAP Applicability (40 CFR 61)

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

7.6 MACT Applicability (40 CFR 63)

The stationary RICE (emergency generator and fire pump) are area sources subject to 40 CFR 63, Subpart ZZZZ because they commenced construction after June 12, 2006. Because these sources are subject to regulation under 40 CFR 60, Subpart IIII, no further requirements are applicable under 40 CFR 63, Subpart ZZZZ. Refer to Table 5.1 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 was not proposed as a major source of HAP emissions.

7.7 CAM Applicability (40 CFR 64)

Although potential pre-control device emissions of NO_x and CO could 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 40 CFR 64.2(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.

40 CFR 64.2 .....Applicability.

(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 (T1 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 7.1, 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 the relevant 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 permit (40 CFR 70).

Therefore, the CT and duct burner are exempt from CAM requirements.

Table 7.1 CT and Duct Burner Compliance Assurance Monitoring Applicability [(a)]

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

a) VOC emissions are shown here for informational purposes only. it was determined that CAM was applicable to VOC emission limits.

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.

7.8 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 Conditions of the permit.

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:

(iii) 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

(iv) 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:

(ii) 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.

(iii) 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.

(iv) 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 Conditions of the permit Refer to the Application Scope And 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 9.8 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 9.2 and 9.4 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 9.5 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 9.12 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 9.14 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 9.20 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 9.2 and 9.5 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 9.2, 9.4, 9.12, 9.14, and 9.20 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.

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[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, Subpart A .....Continuous Emission Monitoring, 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 9.21 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 pertaining to 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, 9.6, 9.10, and 9.11 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 provided showed 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 9.9 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 9.10 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 9.11 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.

Because the permittee has elected to combine emissions for the CT1 (both CT and duct burner), because the CT1 does not have an applicable NO_x emission limitation under the Acid Rain program, because no bypass stack nor multiple stacks are in use, and because the CT1 has not been demonstrated as a LME, the requirements of §§75.16-75.19 were not determined to be applicable, and were not included as permit conditions.

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, and 9.18), the permittee is required to have CEMS QA/QC Plans addressing requirements referenced in this section. Copies of current monitoring plans and protocols are provided in Appendix E – Monitoring Plans & Protocols.

Permit Condition 9.7 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 H2 O) 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, 9.15, and 9.18), the permittee is required to have CEMS QA/QC and Monitoring Plans addressing requirements referenced in this section. Copies of current monitoring plans and protocols are provided in Appendix E – Monitoring Plans & Protocols.

Permit Condition 9.13 incorporates applicable requirements from these sections by reference.

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 NOx CEMS monitoring requirements (Permit Conditions 4.21, 4.24, 9.15, and 9.18), the permittee is required to have CEMS QA/QC and Monitoring Plans addressing requirements referenced in this section. Copies of current monitoring plans and protocols are provided in Appendix E – Monitoring Plans & Protocols.

Permit Condition 9.15 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:*

(1) The data and information required in paragraphs (b) through (h) of this section, beginning with the earlier of the date of provisional certification or the deadline in §75.4(a), (b), or (c);

(2) The supporting data and information used to calculate values required in paragraphs (b) through (g) of this section, excluding the subhourly data points used to compute hourly averages under §75.10(d), beginning with the earlier of the date of provisional certification or the deadline in §75.4(a), (b), or (c);

(3) The data and information required in §75.58 for specific situations, beginning with the earlier of the date of provisional certification or the deadline in §75.4(a), (b), or (c);

(4) The certification test data and information required in §75.59 for tests required under §75.20, beginning with the date of the first certification test performed, the quality assurance and quality control data and information required in §75.59 for tests, and the quality assurance/quality control plan required under §75.21 and appendix B to this part, beginning with the date of provisional certification;

(5) The current monitoring plan as specified in §75.53, beginning with the initial submission required by §75.62;

(6) The quality control plan as described in section 1 of appendix B to this part, beginning with the date of provisional certification; and

(7) The information required by sections 6.1.2(b) and (c) of appendix A to this part.

(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:*

(1) Date and hour;

(2) Unit operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator));

(3) Hourly gross unit load (rounded to nearest MWge) (or steam load in 1000 lb/hr at stated temperature and pressure, rounded to the nearest 1000 lb/hr, or mmBtu/hr of thermal output, rounded to the nearest mmBtu/hr, if elected in the monitoring plan);

(4) Operating load range corresponding to hourly gross load of 1 to 10, except for units using a common stack or common pipe header, which may use up to 20 load ranges for stack or fuel flow, as specified in the monitoring plan;

(5) Hourly heat input rate (mmBtu/hr, rounded to the nearest tenth);

(6) Identification code for formula used for heat input, as provided in §75.53; and

(7) For CEMS units only, F-factor for heat input calculation and indication of whether the diluent cap was used for heat input calculations for the hour.

(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:*

(1) Component-system identification code, as provided in §75.53 (including identification code for the moisture monitoring system, if applicable);

(2) Date and hour;

(3) Hourly average NO_x concentration (ppm, rounded to the nearest tenth) and hourly average NO_x concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in §75.24(d);

(4) Hourly average diluent gas concentration (for NO_x-diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth);

(5) If applicable, the hourly average moisture content of the stack gas (percent H2 O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);

(6) Hourly average NO_x emission rate (for NO_x-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth);

(7) Hourly average NO_x emission rate (for NO_x-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in §75.24(d). The requirement to report hourly NO_x emission rates to the nearest thousandth shall not affect NO_x compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;

(8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_x-diluent or NO_x concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to §75.32;

(9) Method of determination for hourly average NO_x emission rate or NO_x concentration and (if applicable) for the hourly average moisture percentage, using Codes 1-55 in Table 4a of this section; and

(10) Identification codes for emissions formulas used to derive hourly average NO_x emission rate and total NO_x mass emissions, as provided in §75.53, and (if applicable) the F-factor used to convert NO_x concentrations into emission rates.

(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:

(1) If the owner or operator chooses to use a CO_2 CEMS (including an O_2 monitor and flow monitor, as specified in appendix F to this part), then the owner or operator shall record for each hour or partial hour during which the unit operates the following information for CO_2 mass emissions, as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in §75.53 (including identification code for the moisture monitoring system, if applicable);

(ii) Date and hour;

(iii) Hourly average CO_2 concentration (in percent, rounded to the nearest tenth);

(iv) Hourly average volumetric flow rate (scfh, rounded to the nearest thousand scfh);

(v) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth), where CO_2 concentration is measured on a dry basis. If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);

(vi) Hourly average CO_2 mass emission rate (tons/hr, rounded to the nearest tenth);

(vii) Percent monitor data availability for both the CO_2 monitoring system and, if applicable, the moisture monitoring system (recorded to the nearest tenth of a percent), calculated pursuant to §75.32;

(viii) Method of determination for hourly average CO_2 mass emission rate and hourly average CO_2 concentration, and, if applicable, for the hourly average moisture percentage, using Codes 1-55 in Table 4a of this section;

(ix) Identification code for emissions formula used to derive hourly average CO_2 mass emission rate, as provided in §75.53; and

(x) Indication of whether the diluent cap was used for CO_2 calculation for the hour.

(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);

(iii) For coal-fired units, flag indicating whether optional procedure to adjust combustion-formed CO_2 mass emissions for carbon retained in flyash has been used and, if so, the adjustment;

(iv) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, daily sorbent-related CO_2 mass emissions (tons/day, rounded to the nearest tenth); and

(v) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, total daily CO_2 mass emissions (tons/day, rounded to the nearest tenth) as the sum of combustion-formed emissions and sorbent-related emissions.

…

(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:*

(1) Component-system identification code, as provided in §75.53;

(2) Date and hour;

(3) Hourly average diluent gas (O_2 or CO_2) concentration (in percent, rounded to the nearest tenth);

(4) Percent monitor data availability for the diluent monitor (recorded to the nearest tenth of a percent), calculated pursuant to §75.32; and

(5) Method of determination code for diluent gas (O_2 or CO_2) concentration data using Codes 1-55, in Table 4a of this section.

(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 9.16 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:*

…

(2) For units with add-on NO_x emission controls using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing NO_x emission rate data:

(i) Date and hour;

(ii) Inlet air flow rate (scfh, rounded to the nearest thousand);

(iii) Excess O_2 concentration of flue gas at stack outlet (percent, rounded to the nearest tenth of a percent);

(iv) Carbon monoxide concentration of flue gas at stack outlet (ppm, rounded to the nearest tenth);

(v) Temperature of flue gas at furnace exit or economizer outlet duct (°F);

(vi) Other parameters specific to NO_x emission controls (e.g., average hourly reagent feedrate);

(vii) Method of determination of NO_x emission rate using Codes 1-55 in Table 4a of §75.57; and

(viii) Inlet and outlet NO_x emission rate values recorded by a NO_x continuous emission monitoring system and the removal efficiency of the add-on emission controls.

(3) Except as otherwise provided in §75.34(d), for units with add-on SO_2 or NO_x emission controls following the provisions of §§75.34(a)(1), (a)(2), (a)(3) or (a)(5), the owner or operator shall record:

(i) Parametric data which demonstrate, for each hour of missing SO_2 or NO_x emission data, the proper operation of the add-on emission controls, as described in the quality assurance/quality control program for the unit. The parametric data shall be maintained on site and shall be submitted, upon request, to the Administrator, EPA Regional office, State, or local agency;

(ii) A flag indicating, for each hour of missing SO_2 or NO_x emission data, either that the add-on emission controls are operating properly, as evidenced by all parameters being within the ranges specified in the quality assurance/quality control program, or that the add-on emission controls are not operating properly.

(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:*

(1) For each hour when the unit is combusting oil:

(i) Date and hour;

(ii) Hourly average volumetric flow rate of oil, while the unit combusts oil, with the units in which oil flow is recorded (gal/hr, scf/hr, m3 /hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(iii) Sulfur content of oil sample used to determine SO_2 mass emission rate (rounded to nearest hundredth for diesel fuel or to the nearest tenth of a percent for other fuel oil) (flag value if derived from missing data procedures);

(iv) [Reserved];

(v) Mass flow rate of oil combusted each hour and method of determination (lb/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(vi) SO_2 mass emission rate from oil (lb/hr, rounded to the nearest tenth);

(vii) For units using volumetric oil flowmeters, density of oil with the units in which oil density is recorded and method of determination (flag value if derived from missing data procedures);

(viii) Gross calorific value of oil used to determine heat input and method of determination (Btu/lb) (flag value if derived from missing data procedures);

(ix) Hourly heat input rate from oil, according to procedures in appendix D to this part (mmBtu/hr, to the nearest tenth);

(x) Fuel usage time for combustion of oil during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)) (flag to indicate multiple/single fuel types combusted);

(xi) Monitoring system identification code;

(xii) Operating load range corresponding to gross unit load (01-20);

(xiii) Type of oil combusted; and

(xiv) Heat input formula ID and SO_2 Formula ID (required beginning January 1, 2009).

(2) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part for daily manual oil sampling, when the unit is combusting oil, the highest sulfur content recorded from the most recent 30 daily oil samples (rounded to the nearest tenth of a percent).

(3) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part, when either an assumed oil sulfur content or density value is used, or when as-delivered oil sampling is performed:

(i) Record the measured sulfur content, gross calorific value, and, if applicable, density from each fuel sample; and

(ii) Record and report the assumed sulfur content, gross calorific value, and, if applicable, density used to calculate SO_2 mass emission rate or heat input rate.

(4) For each hour when the unit is combusting gaseous fuel:

(i) Date and hour.

(ii) Hourly heat input rate from gaseous fuel, according to procedures in appendix F to this part (mmBtu/hr, rounded to the nearest tenth).

(iii) Sulfur content or SO_2 emission rate, in one of the following formats, in accordance with the appropriate procedure from appendix D to this part:

(A) Sulfur content of gas sample and method of determination (rounded to the nearest 0.1 grains/100 scf) (flag value if derived from missing data procedures); or

(B) Default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas, or calculated SO_2 emission rate for natural gas from section 2.3.2.1.1 of appendix D to this part.

(iv) Hourly flow rate of gaseous fuel, while the unit combusts gas (100 scfh) and source of data code for gas flow rate.

(v) Gross calorific value of gaseous fuel used to determine heat input rate (Btu/100 scf) (flag value if derived from missing data procedures).

(vi) *SO_2 mass emission rate due to the combustion of gaseous fuels (lb/hr).*

(vii) *Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)) (flag to indicate multiple/single fuel types combusted).*

(viii) *Monitoring system identification code.*

(ix) *Operating load range corresponding to gross unit load (01-20).*

(x) *Type of gas combusted; and*

(xi) *Heat input formula ID and SO_2 Formula ID (required beginning January 1, 2009).*

(5) *For each oil sample or sample of diesel fuel:*

(i) *Date of sampling;*

(ii) *Sulfur content (percent, rounded to either the nearest hundredth, or nearest ten-thousandth for diesel fuels and to the nearest tenth for other fuel oil);*

(iii) *Gross calorific value (Btu/lb); and*

(iv) *Density or specific gravity, if required to convert volume to mass.*

(6) *For each sample of gaseous fuel for sulfur content:*

(i) *Date of sampling; and*

(ii) *Sulfur content (grains/100 scf, rounded to the nearest tenth).*

(7) *For each sample of gaseous fuel for gross calorific value:*

(i) *Date of sampling; and*

(ii) *Gross calorific value (Btu/100 scf).*

(8) *For each oil sample or sample of gaseous fuel:*

(i) *Type of oil or gas; and*

(ii) *Type of sulfur sampling (using codes in tables D-4 and D-5 of appendix D to this part) and value used in calculations, and type of GCV or density sampling (using codes in tables D-4 and D-5 of appendix D to this part).*

…

(e) Specific SO_2 emission record provisions during the combustion of gaseous fuel. *(1) If SO_2 emissions are determined in accordance with the provisions in §75.11(e)(2) during hours in which only gaseous fuel is combusted in a unit with an SO_2 CEMS, the owner or operator shall record the information in paragraph (c)(3) of this section in lieu of the information in §§75.57(c)(1), (c)(3), and (c)(4), for those hours.*

(2) *The provisions of this paragraph apply to a unit which, in accordance with the provisions of §75.11(e)(3), uses an SO_2 CEMS to determine SO_2 emissions during hours in which only gaseous fuel is combusted in the unit. If the unit sometimes burns only gaseous fuel that is very low sulfur fuel (as defined in §72.2 of this chapter) as a primary and/or backup fuel and at other times combusts higher sulfur fuels, such as coal or oil, as primary and/or backup fuel(s), then the owner or operator shall keep records on-site, in a form suitable for inspection, of the type(s) of fuel(s) burned during each period of missing SO_2 data and the number of hours that each type of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns very low sulfur fuel exclusively, nor does it apply to a unit that burns such gaseous fuel(s) only during unit startup.*

(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):*

(1) *All low mass emission units shall report for each hour:*

(i) *Date and hour;*

(ii) Unit operating time (units using the long term fuel flow methodology report operating time to be 1);

(iii) Fuel type (pipeline natural gas, natural gas, other gaseous fuel, residual oil, or diesel fuel). If more than one type of fuel is combusted in the hour, either:

(A) Indicate the fuel type which results in the highest emission factors for NO_x (this option is in effect through December 31, 2008); or

(B) Indicate the fuel type resulting in the highest emission factor for each parameter (SO_2, NO_x emission rate, and CO_2) separately (this option is required on and after January 1, 2009);

(iv) Average hourly NO_x emission rate (lb/mmBtu, rounded to the nearest thousandth);

(v) Hourly NO_x mass emissions (lbs, rounded to the nearest tenth);

(vi) Hourly SO_2 mass emissions (lbs, rounded to the nearest tenth);

(vii) Hourly CO_2 mass emissions (tons, rounded to the nearest tenth);

(viii) Hourly calculated unit heat input in mmBtu;

(ix) Hourly unit output in gross load or steam load;

(x) The method of determining hourly heat input: unit maximum rated heat input, unit long term fuel flow or group long term fuel flow;

(xi) The method of determining NO_x emission rate used for the hour: default based on fuel combusted, unit specific default based on testing or historical data, group default based on representative testing of identical units, unit specific based on testing of a unit with NO_x controls operating, or missing data value;

(xii) Control status of the unit; and

(xiii) Base or peak load indicator (as applicable); and

(xiv) Multiple fuel flag.

(2) Low mass emission units using the optional long term fuel flow methodology to determine unit heat input shall report for each quarter:

(i) Type of fuel;

(ii) Beginning date and hour of long term fuel flow measurement period;

(iii) End date and hour of long term fuel flow period;

(iv) Quantity of fuel measured;

(v) Units of measure;

(vi) Fuel GCV value used to calculate heat input;

(vii) Units of GCV;

(viii) Method of determining fuel GCV used;

(ix) Method of determining fuel flow over period;

(x) Monitoring-system identification code;

(xi) Quarter and year;

(xii) Total heat input (mmBtu); and

(xiii) Operating hours in period.

Permit Condition 9.17 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 9.18 incorporates applicable requirements from this section by reference.

40 CFR 75.60 .....General provisions.

(i) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the signatory requirements of §72.21 of this chapter for all submissions.

(j) Submissions. *The designated representative shall submit all reports and petitions (except as provided in §75.61) as follows:*

(1) Initial certifications. *The designated representative shall submit initial certification applications according to §75.63.*

(2) Recertifications. *The designated representative shall submit recertification applications according to §75.63.*

(3) Monitoring plans. *The designated representative shall submit monitoring plans according to §75.62.*

(4) Electronic quarterly reports. *The designated representative shall submit electronic quarterly reports according to §75.64.*

(5) Other petitions and communications. *The designated representative shall submit petitions, correspondence, application forms, designated representative signature, and petition-related test results in hardcopy to the Administrator. Additional petition requirements are specified in §§75.66 and 75.67.*

(6) Semiannual or annual RATA reports. *If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy RATA report within 45 days after completing a required semiannual or annual RATA according to section 2.3.1 of appendix B to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by §75.59(a)(9) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report.*

(7) Routine appendix E retest reports. *If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by §75.59(b)(5) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.*

(k) Confidentiality of data. *The following provisions shall govern the confidentiality of information submitted under this part.*

(1) All emission data reported in quarterly reports under §75.64 shall remain public information.

(2) For information submitted under this part other than emission data submitted in quarterly reports, the designated representative must assert a claim of confidentiality at the time of submission for any information he or she wishes to have treated as confidential business information (CBI) under subpart B of part 2 of this chapter. Failure to assert a claim of confidentiality at the time of submission may result in disclosure of the information by EPA without further notice to the designated representative.

(3) Any claim of confidentiality for information submitted in quarterly reports under §75.64 must include substantiation of the claim. Failure to provide substantiation may result in disclosure of the information by EPA without further notice.

(4) As provided under subpart B of part 2 of this chapter, EPA may review information submitted to determine whether it is entitled to confidential treatment even when confidentiality claims are initially received. The EPA will contact the designated representative as part of such a review process.

Permit Condition 9.19 incorporates applicable requirements from this section by reference.

40 CFR 75.61 .....Notifications.

(a) Submission. *The designated representative for an affected unit (or owner or operator, as specified) shall submit notice to the Administrator, to the appropriate EPA Regional Office, and to the applicable State and local air pollution control agencies for the following purposes, as required by this part.*

(1) Initial certification and recertification test notifications. *The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests and revised test dates as specified in §75.20 for continuous emission monitoring systems, for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii), (a)(1)(iv) and (a)(4) of this section. The owner or operator shall also provide written notification of testing performed under §75.19(c)(1)(iv)(A) to establish fuel-and-unit-specific NO_x emission rates for low mass emissions units. Such notifications are not required, however, for initial certifications and recertifications of excepted monitoring systems under appendix D to this part.*

(i) Notification of initial certification testing and full recertification. *Initial certification test notifications and notifications of full recertification testing under §75.20(b)(2) shall be submitted not later than 21 days prior to the first scheduled day of certification or recertification testing. In emergency situations when full recertification testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.*

(ii) Notification of certification retesting, and partial recertification testing. *For retesting required following a loss of certification under §75.20(a)(5) or for partial recertification testing required under §75.20(b)(2), notice of the date of any required RATA testing or any required retesting under section 2.3 in appendix E to this part shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing; except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as*

notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier.

(iii) Repeat of testing without notice. *Notwithstanding the above notice requirements, the owner or operator may elect to repeat a certification or recertification test immediately, without advance notification, whenever the owner or operator has determined during the certification or recertification testing that a test was failed or must be aborted, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.*

(iv) Waiver from notification requirements. *The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may issue a waiver from the notification requirement of paragraph (a)(1)(ii) of this section, for a unit or a group of units, for one or more recertification tests or other retests. The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may also discontinue the waiver and reinstate the notification requirement of paragraph (a)(1)(ii) of this section for future recertification tests (or other retests) of a unit or a group of units.*

(2) New unit, newly affected unit, new stack, or new flue gas desulfurization system operation notification. *The designated representative for an affected unit shall submit written notification: For a new unit or a newly affected unit, of the planned date when a new unit or newly affected unit will commence commercial operation, or becomes affected, or, for new stack or flue gas desulfurization system, of the planned date when a new stack or flue gas desulfurization system will be completed and emissions will first exit to the atmosphere.*

(i) Notification of the planned date shall be submitted not later than 45 days prior to the date the unit commences commercial operation or becomes affected, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere.

(ii) If the date when the unit commences commercial operation or becomes affected, or the date when the new stack or flue gas desulfurization system exhausts emissions to the atmosphere, whichever is applicable, changes from the planned date, a notification of the actual date shall be submitted not later than 7 days following: The date the unit commences commercial operation or becomes affected, or the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere.

(3) Unit shutdown and recommencement of commercial operation. *For an affected unit that will be shut down on the relevant compliance date specified in §75.4 or in a State or Federal pollutant mass emissions reduction program that adopts the monitoring and reporting requirements of this part, if the owner or operator is relying on the provisions in §75.4(d) to postpone certification testing, the designated representative for the unit shall submit notification of unit shutdown and recommencement of commercial operation as follows:*

(i) For planned unit shutdowns (e.g., extended maintenance outages), written notification of the planned shutdown date shall be provided at least 21 days prior to the applicable compliance date, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual shutdown date or the actual date of recommencement of commercial operation differs from the planned date, written notice of the actual date shall be submitted no later than 7 days following the actual date of shutdown or of recommencement of commercial operation, as applicable;

(ii) For unplanned unit shutdowns (e.g., forced outages), written notification of the actual shutdown date shall be provided no more than 7 days after the shutdown, and written notification of the planned date of recommencement of commercial operation shall be provided at least 21 days in advance of unit restart. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

(4) Use of backup fuels for appendix E procedures. *The designated representative for an affected oil-fired or gas-fired peaking unit that is using an excepted monitoring system under appendix E of this part and that is relying on the provisions in §75.4(f) to postpone testing of a fuel shall submit written notification of that fact no later than 45 days prior to the deadline in §75.4. The designated representative shall also submit a notification that such a fuel has been combusted no later than 7 days after the first date of combustion of any fuel for which testing has not been performed under appendix E after the deadline in §75.4. Such*

notice shall also include notice that testing under appendix E either was performed during the initial combustion or notice of the date that testing will be performed.

(5) Periodic relative accuracy test audits, appendix E retests, and low mass emissions unit retests. *The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under section 2.3.1 of appendix B to this part, of periodic retesting performed under section 2.2 of appendix E to this part, and of periodic retesting of low mass emissions units performed under §75.19(c)(1)(iv)(D), no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the respective State agency or office of EPA, and the notice is provided as soon as practicable after the new testing date is known, but no later than twenty-four (24) hours in advance of the new date of testing.*

(i) Written notification under paragraph (a) (5) of this section may be provided either by mail or by facsimile. In addition, written notification may be provided by electronic mail, provided that the respective State agency or office of EPA agrees that this is an acceptable form of notification.

(ii) Notwithstanding the notice requirements under paragraph (a)(5) of this section, the owner or operator may elect to repeat a periodic relative accuracy test, appendix E retest, or low mass emissions unit retest immediately, without additional notification whenever the owner or operator has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

(iii) Waiver from notification requirements. *The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may issue a waiver from the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for a unit or a group of units for one or more tests. The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may also discontinue the waiver and reinstate the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for future tests for a unit or a group of units. In addition, if an observer from a State agency or EPA is present when a test is rescheduled, the observer may waive all notification requirements under paragraph (a)(5) of this section for the rescheduled test.*

(6) Notice of combustion of emergency fuel under appendix D or E. *The designated representative of an oil-fired unit or gas-fired unit using appendix D or E of this part shall, for each calendar quarter in which emergency fuel is combusted, provide notice of the combustion of the emergency fuel in the cover letter (or electronic equivalent) which transmits the next quarterly report submitted under §75.64. The notice shall specify the exact dates and hours during which the emergency fuel was combusted.*

(7) Long-term cold storage and recommencement of commercial operation. *The designated representative for an affected unit that is placed into long-term cold storage that is relying on the provisions in §75.4(d) or §75.64(a), either to postpone certification testing or to discontinue the submittal of quarterly reports during the period of long-term cold storage, shall provide written notification of long-term cold storage status and recommencement of commercial operation as follows:*

(i) Whenever an affected unit has been placed into long-term cold storage, written notification of the date and hour that the unit was shutdown and a statement from the designated representative stating that the shutdown is expected to last for at least two years from that date, in accordance with the definition for long-term cold storage of a unit as provided in §72.2 of this chapter.

(ii) Whenever an affected unit that has been placed into long-term cold storage is expected to resume operation, written notification shall be submitted 45 calendar days prior to the planned date of recommencement of commercial operation. If the actual date of recommencement of commercial operation differs from the expected date, written notice of the actual date shall be submitted no later than 7 days following the actual date of recommencement of commercial operation.

(8) Certification deadline date for new or newly affected units. *The designated representative of a new or newly affected unit shall provide notification of the date on which the relevant deadline for initial certification is reached, either as provided in §75.4(b) or §75.4(c), or as specified in a State or Federal SO_2 or NO_x mass emission reduction program that incorporates by reference, or otherwise adopts, the monitoring, recordkeeping, and reporting requirements of subpart F, G, or H of this part. The notification shall be submitted no later than 7 calendar days after the applicable certification deadline is reached.*

(b) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems as specified in §75.20(c)(8) to the State or local air pollution control agency.

(c) If the Administrator determines that notification substantially similar to that required in this section is required by any other State or local agency, the owner or operator or designated representative may send the Administrator a copy of that notification to satisfy the requirements of this section, provided the ORISPL unit identification number(s) is denoted.

40 CFR 75.62 .....Monitoring plan submittals.

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

40 CFR 75.64 .....Quarterly reports.

Permit Condition 9.19 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 9.3 includes the requirements of this subsection.

8. PUBLIC COMMENT AND EPA REVIEW

8.1 Public Comment Period

8.2 EPA Review of Proposed Permit

Appendix A – Acid Rain Permit Application

Appendix B – Emission Inventories

Appendix C – Limit Stringency Evaluation

Appendix D – Operation and Maintenance Manual

Appendix E – Monitoring Plans & Protocols