Statement of Basis

Tier I Operating Permit No. T1-2012.0065
Project ID 61124

Idaho Forest Group LLC - Chilco
Athol, Idaho

Facility ID 055-00024

Draft for Public Comment

October 15, 2013

Shawnee Chen, P.E.

Senior Air Quality Engineer

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

1. ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

acfm	actual cubic feet per minute
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BMP	best management practices
Btu	British thermal unit
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems as defined in 40 CFR 63.2
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
CPMS	Continuous parameter monitoring system, as defined in 40 CFR 63.2
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EFB	Electrified filter bed
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
hp	horsepower
hr/yr	hours per consecutive 12 calendar month period
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
IEU	insignificant emissions unit
IFG	Idaho Forest Group, LLC, Riley Creek-Chilco Facility
iwg	inches of water gauge
km	kilometers
lb/hr	pounds per hour
m	meters
MACT	Maximum Achievable Control Technology
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
MRRR	Monitoring, Recordkeeping and Reporting Requirements
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
O_2	oxygen
PC	permit condition

PCWP	Plywood and Composite Wood Products
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTE	potential to emit
PW	process weight rate
RICE	reciprocating internal combustion engines
Rules	*Rules for the Control of Air Pollution in Idaho*
scf/hr	standard cubic feet per hour
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T1	Tier I operating permit
T2	Tier II operating permit
TAP	toxic air pollutants
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
ULSD	ultra low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compound

2. INTRODUCTION AND APPLICABILITY

Idaho Forest Group, LLC, Riley Creek-Chilco Facility (IFG) is a manufacturer of dimensional lumber and located at 4447 East Chilco Road, in Athol. The facility is classified as a major facility, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit nitrogen oxide (NOx), carbon monoxide (CO), and volatile organic compounds (VOCs) above the major source threshold of 100 tons-per-year. The facility is also classified as a major facility, as defined by IDAPA 58.01.01.008.10.a, because it emits or has the potential to emit methanol and acetaldehyde above the major source thresholds of 10 tons-per-year for any single HAP and 25 tons-per-year for any combination of HAP.

As a major facility, IFG is required to apply for a Tier I operating permit pursuant to IDAPA 58.01.01.301. The application for a Tier I operating permit must contain a certification from IFG as to its compliance status with all applicable requirements (IDAPA 58.01.01.314.09).

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

The format of this Statement of Basis follows that of the permit with the exception of the facility's information discussed first followed by the scope, the applicable requirements and permit shield, and finally the general provisions.

IFG Tier I operating permit is organized into sections. They are as follows:

Section 1 – Acronyms, Units, and Chemical Nomenclature

Section 1 includes acronyms, units, and chemical nomenclature.

Section 2 - Tier I Operating Permit Scope

The scope describes this permitting action.

Section 3 - Facility-Wide Conditions

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

Sections 4 through 9 - Emissions Units / Sources

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

Section 10 - Insignificant Activities

This section lists those requirements that the applicant has requested as non-applicable, and DEQ proposes to grant a permit shield in accordance with IDAPA 58.01.01.325.

If requested by the applicant, this section also lists emissions units and activities determined to be insignificant activities based on size or production as allowed by IDAPA 58.01.01.317.01.b.

Section 11 - 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 all terms required by IDAPA 58.01.01 et al as well as requirements from other air quality laws and regulations. Each general provision has been paraphrased so it is more easily understood by the general public; however, there is no intent to alter the effect of the requirement. Should there be a discrepancy between a paraphrased general provision in this statement of basis and the rule or permit, the rule or permit shall govern.

3. FACILITY INFORMATION

3.1 Facility Description

IFG produces dimensional lumber which is located at Athol, ID. The primary processes at the facility are the sawmill, steam plant (i.e., the boilers), drying lumber kilns, planermill, and by-products handling.

Logs are stored in the log yard until they can be processed. Logs are debarked then cut to dimension in the sawmill. Bark from the debarker is hogged and pneumatically transferred to hog fuel storage or to the hog fuel boiler. Surplus bark is sold as a by-product. Green lumber is cut to length in the sawmill, dried in the facility’s kilns, and planed in the planermill. The finished lumber is packaged and shipped by truck or by railcar. By-products include bark, sawdust, sawmill chips, planer chips, and shavings.

3.2 Facility Permitting History

Tier I Operating Permit History - Previous 5-year permit term May 2, 2008 to October 15, 2013

The following information is the permitting history of the Tier I operating permit for this Tier I facility during the previous five-year permit term which was from May 2, 2008 to October 15, 2013. 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).

Permit Type	Permit Number	Issue Date	Project	Status
T1	T1-050123	5/2/08	Initial Tier 1	S
T1	T1-2008.0202	01/13/09	Administrative amendment - change name of facility, facility contact, and responsible official	S
T1	T1-2009.0123	10/5/09	Administrative amendment - change name of responsible official	A (will be S after the issuance of this permit)

Underlying Permit History - Includes every underlying permit

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

Permit Type	Permit Number	Issue Date	Project	Status
PTC	P-030132	02/18/04	Transfer ownership from Louisiana-Pacific Corp to Chilco Lake Lumber Co. LLC	S
PTC	P-040100	08/20/04	For the construction of a hog fuel boiler with EFB, ash handling equip, EFB baghouse, NG boiler, kilns, planer mill, planer chipper, chip bin, shavings bin with cyclone and baghouse	S
PTC	P-050116	09/01/05	Increase CO emission, remove conditions on NG boiler, planer shaving baghouse, and planer chip target bin, add hog fuel cyclone	S
PTC	No. P-2013.0005 PROJ 61153	5/10/2013	Decrease the annual CO emissions limit, remove all conditions related to the hog fuel cyclone, and put permit conditions related to the planer shavings baghouse and planer chip bin target box back into the permit.	A

Underlying Documents – Consent Order, etc.

IFG does not have active consent orders or settlement agreements at the time of issuing this permit.

4. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

4.1 Application Scope

This permit is the renewal of the facility's currently effective Tier I operating permit. This permit includes the following changes to the existing permit:

- Add the requirements in 40 CFR 64 that apply to the hog fuel boiler.
- Add the requirements in 40 CFR 63, Subpart DDDDD that apply to the hog fuel boiler.
- Add the natural gas-fired boiler section, including the requirements in 40 CFR 60 Subpart Dc and 40 CFR 63, Subpart DDDDD that apply to the boiler.
- Add the requirements in 40 CFR 63, Subpart ZZZZ that apply to the fire-water pump engine.

- Incorporate the requirements in PTC No. P-2013.0005 PROJ 61153 issued May 10, 2013.
- Update insignificant activities list.
- Remove Hog Fuel Cyclone section.
- Correct “five dry kilns” to “four dry kilns”
- Remove “Fire Water Pump” and “Small Generators and Compressors” from the insignificant list.

4.2 Application Chronology

October 11, 2012	DEQ received an application.
December 5, 2012	DEQ received application addendum regarding natural gas-fired boiler through email (hard copy was received on December 10, 2012).
December 7, 2012	DEQ determined that the application was complete.
January 29, 2013	DEQ made available the draft permit and statement of basis for peer and regional office review.
February 9, 2013	DEQ made available the draft permit and statement of basis for applicant review.
March 4, 2013	DEQ received application supplement including Form FRA for 40 CFR 63, Subpart DDDDD.
May 14, 2013	DEQ made available the 2nd draft permit and statement of basis for applicant review, including the requirements taken from 40 CFR 63, Subpart DDDDD and from PTC No. P- P-2013.0005 PROJ 61153 issued on 5/10/2013.

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

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

5.1 Process No. 1 - HOG FUEL BOILER

Table 5.1 lists the emissions units and control devices associated with the hog fuel boiler.

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

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Hog fuel boiler Manufacturer: Kipper and Sons, #1018 Date Manufactured: 1977 Rated heat capacity: 125 MMBtu/hr Rated steam capacity: 75,000 pounds steam per hour (permitted at 607,594 thousand pounds of steam per any consecutive 12-month period) Burner type: Spreader stoker Fuel: Woodwaste Stack flow rate: 43,000 acfm	Multiclone Manufacturer: Western Pneumatics, Inc. Efficiency: 95% for PM Electrified filter bed (EFB) fine dust collector Manufacturer: EFB Inc. Model number: EFB FDC 75 Efficiency: 99% for PM	Hog fuel boiler EFB stack
	EFB Dust Collector	The PM emissions from cleaning the EFB filter media are controlled by the	EFB baghouse

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
		EFB baghouse, which has a PM control efficiency of 99% or greater.	vent

The hog fuel boiler provides steam to heat the facility's dry kilns and the facility's production buildings. The hog fuel boiler is rated at 75,000 pounds of steam per hour or 125 MMBtu/hr and is limited to 607,594 thousand pounds of steam per any consecutive 12-month period.

Emissions resulting from combustion in the hog fuel boiler are first routed to a high efficiency multiclone. The multiclone is the primary PM emission control device. Ash and partially combusted wood fiber removed by the multiclone are then segregated by a classifier. From the classifier, partially combusted wood fiber is reintroduced back into the boiler firebox, and the ash is removed for disposal. After the multiclone, the uncaptured fine dust and smoke particles are collected in an electrified filter bed (EFB) dust collector. The cleaned air stream is vented through the boiler's EFB stack. When the EFB dust collector is cleaned, the dust-laden air stream is vented to the EFB baghouse. Emissions from the EFB baghouse exit to the atmosphere through the EFB baghouse vent.

5.2 Process No. 2 - DRY KILNS (FOUR TOTAL)

Table 5.2 lists the emissions units and control devices associated with dry kilns.

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

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Four dry kilns	None	Vents

The dry kilns are used to dry green lumber. Lumber is dried by the steam produced by the facility's boilers. Vents on the dry kilns are opened and closed during batch drying cycles to control temperature and moisture within the kilns.

5.3 Process No. 3 - SAWMILL

Table 5.3 lists the emissions units and control devices associated with the sawmill.

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

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Sawmill chip bin target box	None	Target box
NA	Sawdust bin target box	None	Target box

Logs are debarked and cut into dimensional lumber in the sawmill. As a result of these processes, wood scraps and sawdust are produced. The wood scraps are chipped in a chipper. The fine size material is screened and added to sawdust that is pneumatically conveyed to the sawdust bin target box located on the outdoor sawdust bin. Chips are pneumatically transferred to a sawmill chip bin target box on the outdoor sawmill chip bin.

The sawdust building enclosure controls emissions from the sawing of logs and chipping of wood scrap.

5.4 Process No. 4 - FIRE-WATER PUMP ENGINE

Table 5.4 lists the emissions units and control devices associated with the fire-water pump engine.

Table 5.4 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Fire-water pump engine Manufacturer: Cummins Model: V-504-52 Date Manufactured: January 1983 Date installed: 2004 Rated capacity: 150 brake horsepower Fuel: Diesel	None	Engine stack

The fire-water pump engine is a diesel-fired CI RICE with a site rating of 150 brake hp. It was installed in 2004. The fire-water pump engine is an emergency engine. It is only used for fire suppression. It is tested regularly to ensure readiness.

5.5 Process No. 5 - NATURAL GAS-FIRED BOILER

Table 5.5 lists the emissions units and control devices associated with the natural gas-fired boiler.

Table 5.5 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Natural gas-fired boiler Manufacturer: Indeck Model: NOS-1A-53S Date Manufactured: 2008 Rated capacity: 46 MMBtu/hr Fuel: Natural gas	None	Natural gas-fired boiler stack

The facility has installed a package natural gas-fired boiler in December 2012. The boiler was exempt from obtaining a PTC. The boiler is rated at 46 MMBtu/hr or 40,000 pounds of steam per hour.

The steam is for process use. Emissions from the natural gas-fired boiler are uncontrolled.

5.6 Process No. 6 - PLANER MILL

Table 5.6 lists the emissions units and control devices associated with the planer mill.

Table 5.6 EMISSIONS UNITS, CONTROL DEVICE, AND DISCHARGE POINT INFORMATION

Emissions Unit ID No.	Emissions Unit Description	Control Device (if applicable)	Emission Point ID No.
NA	Planer Shaving Cyclone	Fabric Filter Baghouse	Planer Shavings Cyclone Baghouse Vent
	Planer Chip Bin Target Box	None	Planer Chip Bin Target Box Vent

The planer and associated equipment reduce dried or green lumber to a desired width and thickness. Planer shavings generated by the process are transported pneumatically from the planer building to a cyclone on the shavings bin. The cyclone separates out the shavings from the air stream and drops them into the planer shavings bin. Planer chips generated by the process are pneumatically transported to a planer chip bin target box on the planer chip bin.

Emissions generated from the planer and associated equipment located inside the building are controlled by the building enclosure. Emissions resulting from the transport of planer shavings to the shavings bin are controlled by a baghouse on the planer shavings cyclone. Emissions resulting from the transport of planer chips to the planer chip bin target box are uncontrolled. Emissions from the planer shavings cyclone baghouse vent or the planer chip bin target box vent may be exhausted either back inside the building or outside the building.

5.7 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, insignificant emissions units (IEUs) based on size or production rate must be listed in the permit application. Table 5.6 lists the IEUs identified in the permit application. Also summarized is the regulatory authority or justification for each IEU.

Table 5.6 INSIGNIFICANT EMISSION UNITS AND REGULATORY AUTHORITY/JUSTIFICATION

Emissions Unit / Activity	Regulatory Authority / Justification
Bark Hog	IDAPA 58.01.01.317.01(b)(i)(30)
Covered Bark Conveyor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Screen (classifier), indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chipper, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Transfer to Fuel House	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Truck Bin Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chipper and Screen	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Shavings Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)

5.8 Emissions Inventory (EI)

Table 5.7 summarizes the emissions inventory for this major facility. All values are expressed in units of tons-per-year and represent the facility's potential to emit. Potential to emit is defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hour of operation or on the type or amount of material combusted, stored or processed shall be treated as part of its design if the limitation or the effect it would have on emission is state or federally enforceable.

Details on the revised EI can be found in the application supplement received on December 31, 2012. The PTE for lead and greenhouse gases (GHG) are 2.32 x 10^{-2} T/yr and 27,558 T/yr, respective.

Table 5.7 EMISSIONS INVENTORY - POTENTIAL TO EMIT (T/yr) [1]

	PM_{10} T/yr	$PM_{2.5}$ T/yr	SO_2 T/yr	NO_x T/yr	VOCs T/yr	CO T/yr	HAPs T/yr
Fugitive Sources							
Log and Bark Handling, Fugitives							
Debarker	3.22	0.97	---	---	---	---	---
Bark Hog	0.59	0.18	---	---	---	---	---
Covered Bark Conveyor	0.59	0.18	---	---	---	---	---
Hogged Fuel Drop in Fuel House	0.94	0.28	---	---	---	---	---
Hogged Fuel Truck Bin Loadout	0.59	0.18	---	---	---	---	---
Sawmill Fugitives							
Sawmill, Indoor	1.17	0.12	---	---	---	---	---
Sawmill Screen (Classifier), Indoor	0.63	0.06	---	---	---	---	---
Sawmill Chipper, Indoor	0.63	0.19	---	---	---	---	---

	PM_{10} T/yr	$PM_{2.5}$ T/yr	SO_2 T/yr	NO_x T/yr	VOCs T/yr	CO T/yr	HAPs T/yr
Sawdust Bin Truck Loadout	1.33	0.40	---	---	---	---	---
Sawmill Chip Bin Truck Loadout	3.13	0.94	---	---	---	---	---
Planer, Fugitives							
Planer Chipper and Screen	0.13	0.04	---	---	---	---	---
Planer Chip Bin Truck Loadout	1.25	0.38	---	---	---	---	---
Planer Shavings Bin Truck Loadout	1.50	0.45	---	---	---	---	---
Fugitive Road Dust							
Fugitive Dust - Paved Roads	0.49	0.12	---	---	---	---	---
Fugitive Dust Totals	**16.16**	**4.46**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Point Sources							
Lumber Drying							
Lumber Dry Kilns	3.25	1.63	---	---	175	---	31.2
Sawmill Point Sources							
Sawmill Chip Bin Vent - Point Source	6.27	1.88	---	---	---	---	---
Sawdust Bin Vent - Point Source	2.65	0.80	---	---	---	---	---
Firewater Pump	0.08	0.08	0.08	1.19	0.10	0.26	0.002
Planer Point Sources							
Planer Chipper Target Box - Point Source	1.25	0.38	---	---	---	---	---
Planer Shavings Cyclone Baghouse - Point Source	5.44	1.63	---	---	---	---	---
Steam Plant							
Hog Fuel Boiler	30.4	27.3	12.1	106	29.9	238	19.3
EFB Media Baghouse	1.0	1.0	---	---	---	---	---
Natural Gas Boiler (BRC)	1.5	1.5	0.12	7.39	1.09	7.50	0.37
Point Source Totals	**52**	**36**	**12**	**115**	**206**	**246**	**50.9**
Plant Wide Total	**68.0**	**40.7**	**12.3**	**115**	**206**	**246**	**50.9**

[1] Assumptions were made on what percentage of PM_{10} emissions was $PM_{2.5}$ for different processes. The assumptions are not verified for this project because these assumptions do not alter the classification of the facility.

6. EMISSIONS 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. The first subsection lists the requirements that apply facility wide. The next subsection lists the emissions units- and emissions activities-specific applicable requirements. The final subsection contains the general provisions that apply to all major facilities subject to Idaho DEQ's Tier I operating permit requirements.

This section contains the following subsections:

- Facility-Wide Conditions;

- Emissions Unit No. 1 Hog Fuel Boiler;
- Emissions Unit No. 2 Dry Kilns;
- Emissions Unit No. 3 Sawmill;
- Emissions Unit No. 4 Fire-Water Pump Engine;
- Emissions Unit No. 5 Natural gas-fired boiler;
- Emissions Unit No. 6 Planer mill;
- Tier I Operating Permit General Provisions.

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. This is known 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, such as monitoring, recordkeeping, performance testing, reporting, and certification requirements.

The discussion of each permit condition includes the legal and factual basis for the permit condition. If a permit condition was changed due to facility draft or public comments, a description of why and how the condition was changed is provided.

State Enforceability

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

Federal Enforceability

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

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

6.1 Facility-Wide Conditions

Permit Condition 3.1 - Fugitive Dust

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

[IDAPA 58.01.01.650-651, 3/30/07]

MRRR (Permit Conditions 3.2 through 3.4)

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

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

[IDAPA 58.01.01.322.06, 07, 08, 4/5/2000]

Permit Condition 3.5 - Odors

The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution.

[IDAPA 58.01.01.775-776 (State-only), 5/1/94]

MRRR (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 if the complaint has merit, and log the date and corrective action taken.

[IDAPA 58.01.01.322.06, 07 (State only), 5/1/94]

Permit Condition 3.7 - Visible Emissions

The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section.

[IDAPA 58.01.01.625, 4/5/00]

MRRR (Permit Conditions 3.8 through 3.9)

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

[IDAPA 58.01.01.322.06, 07, 5/1/94]

Permit Conditions 3.10 through 3.14 - Excess Emissions

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

MRRR (Permit Conditions 3.10 through 3.14)

Monitoring, recordkeeping and reporting requirements for excess emissions are provided in IDAPA 58.01.01.131-136.

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

Permit Condition 3.15 – Fuel-Burning Equipment PM Standards

The permittee shall not discharge to the atmosphere from any fuel-burning equipment PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas.

[IDAPA 58.01.01.676-677, 5/1/94]

MRRR

No specific monitoring is required for this facility-wide condition otherwise. 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. The natural gas-fired boiler will be in comply with the standard as long as the boiler burns natural gas.

Permit Condition 3.16 - Sulfur Content Limits

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

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

[IDAPA 58.01.01.725, 3/29/10]

MRRR - (Permit Condition 3.17)

The permittee shall maintain documentation of supplier verification of fuel sulfur content on an as received basis. The facility does not use coal.

[IDAPA 58.01.01.322.06, 5/1/94]

Permit Condition 3.18 - Open Burning

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

[IDAPA 58.01.01.600-623, 5/08/09]

MRRR

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

Permit Condition 3.19 - Asbestos

The permittee shall comply with all applicable portions of 40 CFR 61, Subpart M when conducting any renovation or demolition activities at the facility.

[40 CFR 61, Subpart M]

MRRR

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

Permit Condition 3.20 - Accidental Release Prevention

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

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

[40 CFR 68.10 (a)]

MRRR

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

Permit Condition 3.21 - Recycling and Emissions Reductions

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

[40 CFR 82, Subpart F]

MRRR

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

Permit Condition 3.22 - Monitoring and Recordkeeping

The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating permit. Records of monitoring information shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

MRRR

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

Permit Conditions 3.23 through 3.26 - Performance Testing

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

All testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

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

- The proposed schedule for conducting and reporting the test

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

MRRR (Permit Conditions 3.25 and 3.26)

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

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

Permit Condition 3.27 - Reports and Certifications

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

[IDAPA 58.01.01.322.08, 11, 5/1/94]

MRRR

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

Permit Condition 3.28 - Incorporation of Federal Requirements by Reference

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

[IDAPA 58.01.01.107, 4/7/11]

MRRR

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

Old Permit Condition 2.19 – Configuration Requirements for Planer Shaving Cyclone Baghouse Stack and The Planer Chip Target Box

This permit condition is removed because it is removed from the underlying PTC, issued on 5/10/2013.

6.2 Emissions Unit-Specific Emissions Limits and MRRR

For additional discussions on the emissions limits and MRRR, refer to the SOB for the initial Tier I issued on September 1, 2005.

HOG FUEL-FIRED BOILER

In Table 2.1, the stack flow rate for the hog fuel-fired boiler is changed from 31,349 to 43,000 acfm based on the 2009 source test data.

Permit Condition 4.1

PC 4.1 regarding PM_{10} emissions limits for the hog fuel-fired boiler stack, also called electrified filter bed (EFB) stack, is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 4.8, 4.9, 4.10, 4.12, 4.14, 3.25, and 4.17 through 4.29)

No changes are made to the existing MRRR except that the CAM requirements are new. Discussions on the CAM requirements can be found under Regulatory Review Section and Appendix B. Demonstrating compliance with PC 4.1 was either specified in the underlying PTC issued on 5/10/2013, established in accordance with IDAPA 58.01.01.322.06, 07, & 08, or is developed in accordance with 40 CFR 64 (CAM). The following summarizes the methods used to demonstrate compliance:

- Require to use EFB and EFB baghouse when the hog fuel boiler is in operation. (PC 4.8)
- Measure, monitor, and record the pressure differential across the EFB baghouse. (PCs 4.9 & 4.14)

- Maintain the pressure drop across the EFB baghouse within manufacturer specifications and recommendations. (PC 4.10)
- Conduct performance test (PC 4.12) and report the testing results (PC 3.25)
- Comply with the CAM requirements developed in accordance with 40 CFR 64. (PCs 4.17 to 4.29)

<u>Permit Condition 4.12</u>

Permit Condition 4.12 is revised to reflect that a source test was conducted on 7/29/2009. The tested emissions rate was 3.73 lb/hr (54% of the limit) and 0.0136 gr/dscf (17% of the limit). According to PC 4.12, a subsequent compliance test shall be conducted within five years of the test date. The new date is therefore set as 7/29/2014.

The CAM plan includes voltage and current for the bed and ionizer. They are required to be monitored during testing and are added to PC 4.12.

Minor edits are made for clarity.

The PM_{10} emissions rate is more stringent than the grain loading standard. Only testing schedule for PM_{10} will be needed.

PC 4.12 is revised and read as follows:

"4.12 **On or before July 29, 2014**, the permittee shall conduct a compliance test to measure **particulate** ~~PM10~~ emissions from the hog fuel boiler **EFB** stack to demonstrate compliance with **the PM_{10} emissions limt of** Permit Condition 4.1 and the **PM** grain loading standard of Permit Condition 4.5 … ~~The results of the compliance test shall be expressed in units of lb/hr and the average period is as determined by source test method prescribed by IDAPA 58.01.01.157.~~ The permittee shall monitor and record the following information during the compliance testing:

…

- EFB bed inlet temperature, EFB bed voltage **and current**, and EFB ionizer **voltage and** current.

…"

<u>Old Permit Condition 3.16</u>

The reporting requirements in old PC 3.16 duplicate Permit Condition 3.25 and are removed.

<u>New Permit Conditions 4.17 through 4.29 – CAM requirements</u>

The applicant proposed the CAM indicators. DEQ staff reviewed and approved the indicators with minor changes. The hog fuel-fired boiler does not meet the definition of *large pollutant-specific emissions units* in CAM, therefore the frequency of data collection is at least once per 24-hour period.

The 7/29/2009 source test demonstrated compliance with the standards. The recorded indicators' values are within the proposed CAM indicators' ranges, e.g., the filter bed current was 0.02 mA for module 1 and 0.03 for module 2, the media baghouse pressure drop was 0.4 inch of water.

New Permit Conditions 4.17 through 4.29 are developed in accordance with 40 CFR 64. PCs 4.19 through 4.29 are taken from the current Tier I operating permit template.

Permit Condition 4.2

PC 4.2 regarding PM_{10} emissions limits for the EFB baghouse stack is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 4.8, 4.9, 4.10, and 4.14)

Demonstrating compliance with PC 4.2 was either specified in the underlying PTC issued on 5/10/2013 or established in accordance with IDAPA 58.01.01.322.06&07. The following summarizes the methods used to demonstrate compliance:

- Require to use EFB and EFB baghouse when the hog fuel boiler is in operation. (PC 4.8)
- Measure, monitor, and record the pressure differential across the EFB baghouse. (PCs 4.9 & 4.14)
- Remain the pressure drop across the EFB baghouse within manufacturer specifications and recommendations. (PC 4.10)

Permit Condition 4.3

PC 4.3 regarding CO emissions limits for the boiler's EFB stack is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 4.7, 4.11, 4.13, and 3.25)

Demonstrating compliance with PC 4.3 was either specified in the underlying PTC issued on 5/10/2013 or established in accordance with IDAPA 58.01.01.322.06, 07, & 08. The following summarizes the methods used to demonstrate compliance:

- Limit steam production rate (PC 4.7) and monitor and record steam production rate. (PC 4.13)
- Conduct performance test (PC 4.11) and report the testing results (PC 3.25)

Permit Condition 4.3

As a result of the underlying PTC change, PC 4.3 is revised and read as follows:

"4.3 ~~The carbon monoxide (CO) emissions from the boiler's EFB stack shall not exceed 0.81 lb CO/1,000 lb steam produced and 246.08 T/yr, as determined by source test methods prescribed by IDAPA 58.01.01.157.~~

The carbon monoxide (CO) emissions from the boiler's EFB stack shall not exceed 0.785 lb CO/1,000 lb steam produced and 246 tons per consecutive 12-month period. The annual CO limit includes CO emissions from a temporary/exempt boiler whenever a temporary/exempt boiler is also used at the facility."

Permit Condition 4.7

As a result of the underlying PTC change, PC 4.7 is revised and read as follows:

The steam production rate of the hog fuel boiler shall not exceed **607,594 thousand pounds of steam per any consecutive 12-month period**~~.69,360 pounds of steam per hour averaged over any consecutive 24-hour period~~.

Permit Condition 4.11

IFG conducted a source test on July 29, 2009. The test result was 0.58 lb CO/1,000 lb steam, which is 74% of the permit limit. According to the testing schedule in the underlying PTC, the upcoming source test date is specified. PC 4.3 is revised and read as follows:

"**4.11 Carbon Monoxide Performance Tests**

4.11.1 On or before July 30, 2014, the permittee shall conduct a compliance test to measure CO emissions from the hog fuel boiler to demonstrate compliance with Permit Condition 4.3. The performance test shall be conducted in accordance with Permit Conditions 3.23 to 3.26. The results of the performance test shall be expressed in terms of pounds of CO emitted per 1,000-pounds of steam produced (lb CO/1,000 lb steam).

4.11.2 Subsequent performance tests shall be conducted according to the following schedule:

- **If the CO emissions measured during the most recent performance test are less than or equal to 75% of the CO emissions limit listed in Permit Condition 4.3, a subsequent performance test shall be conducted within five years of the test date.**
- **If the CO emissions measured during the most recent performance test are greater than 75%, but less than or equal to 90% of the CO emissions limit listed in Permit**

Condition 4.3, a subsequent performance test shall be conducted within two years of the test date.

- **If the CO emissions measured during the most recent performance test are greater than 90% of the CO emissions limit listed in Permit Condition 4.3, a subsequent performance test shall be conducted within 13 months of the test date.**

~~4.11 …, the permittee shall conduct a compliance test to measure CO emissions from the hog fuel boiler stack to demonstrate compliance with Permit Condition 4.4. The compliance test shall be conducted in accordance with Permit Conditions 3.23 to 3.26. The permittee is encouraged to submit a source testing protocol for approval 30 days prior to conducting the performance test. The results of the compliance test shall be expressed in terms of pounds of CO emitted per 1,000 pounds of steam produced (lbs CO/1,000 lbs steam) and in tons of CO per year. Subsequent compliance tests shall be conducted according to the following schedule:~~

~~If the CO emissions measured during the compliance test are less than or equal to 75% of the CO emissions limit listed in Permit Condition 4.3, a subsequent compliance test shall be conducted within five years of the test date.~~

~~If the CO emissions measured during the compliance test are greater than 75% but less than or equal to 90% of the CO emissions limit listed in Permit Condition 4.3, a subsequent compliance test shall be conducted within two years of the test date.~~

~~If the CO emissions measured during the compliance test are greater than 90% of the CO emissions limit listed in Permit Condition 4.3, a subsequent compliance test shall be conducted within 12 months of the test date.~~"

A source test was conducted on 7/29/2009. The tested emissions rate was 72% of the limit.

Permit Condition 4.13

As a result of the underlying PTC change, PC 4.13 is changed and read as follows:

"4.13 ~~The permittee shall monitor and record the average hourly steam production rate over any consecutive 24 hour period to demonstrate compliance with Permit Condition 4.7. This information shall be maintained in accordance with Permit Condition 3.22~~.

Each month, the permittee shall monitor and record the steam production rate that month in terms of 1000-pounds per month and 1000-pounds for the most recent consecutive 12-month period to demonstrate compliance with Permit Condition 4.7. This information shall be maintained in accordance with Permit Condition 3.22."

Permit Condition 4.4

PC 4.4 regarding formaldehyde emissions limits for the boiler's EFB stack is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 4.7 and 4.13)

Demonstrating compliance with PC 4.4 was taken from the underlying PTC issued on 5/10/2013 and established in accordance with IDAPA 58.01.01.322.06 & 07. The following summarizes the methods used to demonstrate compliance:

- Limit steam production rate (PC 4.7) and monitor and record steam production rate. (PC 4.13)

Permit Condition 4.5

PC 4.5 regarding PM emissions limits for the hog fuel-fired boiler stack, also called EFB stack, is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 4.8, 4.9, 4.10, 4.12, 4.14, and 3.25)

Demonstrating compliance with PC 4.5 was either specified in the underlying PTC issued on 5/10/2013 or established in accordance with IDAPA 58.01.01.322.06, 07, & 08. The following summarizes the methods used to demonstrate compliance:

- Require to use EFB and EFB baghouse when the hog fuel boiler is in operation. (PC 4.8)
- Measure, monitor, and record the pressure differential across the EFB baghouse. (PCs 4.9 & 4.14)
- Remain the pressure drop across the EFB baghouse within manufacturer specifications and recommendations. (PC 4.10)
- Conduct performance test (PC 4.12) and report the testing results (PC 3.25)

Permit Condition 4.5

A correction is made to keep the permit condition being consistent with the Rules. The revised PC 4.5 reads as follows:

"4.5 The PM emissions from the boiler's EFB stack shall not exceed 0.08**0** gr/dscf corrected to 8% oxygen by volume when burning wood product."

Permit Condition 4.6

PC 4.6 regarding visible emissions limit is taken from the PTC issued on 5/10/2013. It applies to the boiler's EFB stack and the EFB baghouse vent. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 4.8, 4.9, 4.10, 4.14, and 4.15)

Demonstrating compliance with PC 4.6 was either established in accordance with IDAPA 58.01.01.322.06 or specified in the underlying PTC issued 5/10/2013. The following summarizes the methods used to demonstrate compliance:

- Require to use EFB and EFB baghouse when the hog fuel boiler is in operation. (PC 4.8)
- Measure, monitor, and record the pressure differential across the EFB baghouse. (PCs 4.9 & 4.14)
- Remain the pressure drop across the EFB baghouse within manufacturer specifications and recommendations. (PC 4.10)
- Monthly facility-wide see/no see inspection (PC 4.15)

New Permit Conditions 4.30 to 4.94 (Boiler MACT)

The hog fuel boiler is subject to 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. The boiler is subject to emission limitations, work practice standards, and operating limits in the subpart. The MRRR is specified in the subpart. The table of content of the subpart clearly outlines the MRRR. Detailed regulatory analysis, including the table of content of the subpart, can be found in Appendix B.

DRY KILNS (4 TOTAL)

Permit Conditions 5.1, 5.2, and 5.3

PCs 5.1, 5.2, and 5.3 regarding PM_{10}, VOC, and Formaldehyde emissions limits for the dry kilns vents are taken from the PTC issued on 5/10/2013. They are applicable requirements according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 5.5 and 5.6)

No changes are made to the MRRR for this renewal. Demonstrating compliance with PCs 5.1, 5.2, and 5.3 was either specified in the underlying PTC issued on 5/10/2013 or established in accordance with

IDAPA 58.01.01.322.07, 08, & 09. The following summarizes the methods used to demonstrate compliance:

- Limit annual lumber throughput. (PC 5.5)
- Monitor and record throughput rate monthly and annually and in accordance with PC 3.22. (PC 5.6)

Permit Condition 5.4

PC 5.4 regarding visible emissions limits for the dry kilns vents is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Condition 5.7)

No changes are made to the MRRR for this renewal. Demonstrating compliance with PC 5.4 was specified in the underlying PTC issued on 5/10/2013 and established in accordance with IDAPA 58.01.01.625. The following summarizes the methods used to demonstrate compliance:

- Monthly facility-wide see/no see inspection (PC 5.7)

SAWMILL

Permit Conditions 6.1 and 6.2

PCs 6.1 and 6.2 regarding PM_{10} emissions limits for the sawmill chip bin target box vent and the sawdust bin target box vent are taken from the PTC issued on 5/10/2013. They are applicable requirements according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 6.4 and 6.5)

No changes are made to the MRRR for this renewal. Demonstrating compliance with PCs 6.1 and 6.2 was specified in the underlying PTC issued on 5/10/2013. The following summarizes the methods used to demonstrate compliance:

- Limit annual throughputs of the sawmill chip bin and the sawdust bin. (PC 6.4)
- Monitor and record throughput rate monthly and annually and in accordance with PC 3.22. (PC 6.5)

Permit Condition 6.3

PC 6.3 regarding visible emissions limit is taken from the PTC issued on 5/10/2013. It is an applicable requirement according to IDAPA 58.01.01.008.03.

MRRR - (Permit Condition 6.6)

No changes are made to the MRRR for this renewal. Demonstrating compliance with PC 6.3 was specified in the underlying PTC issued on 5/10/2013 and established in accordance with IDAPA 58.01.01.625. The following summarizes the methods used to demonstrate compliance:

- Monthly facility-wide see/no see inspection (PC 6.6)

FIRE-WATER PUMP ENGINE

This is a new permit section. The engine is subject to requirements in 40 CFR 63, Subpart ZZZZ. Detailed discussions can be found under Regulatory Review section and Appendix B. The requirements in 40 CFR 63, Subpart ZZZZ are applicable requirements according to IDAPA 58.01.01.008.03.

Permit Condition 7.3

PC 7.3 is emissions and operating limitations taken from 40 CFR 63, Subpart ZZZZ.

MRRR - (Permit Conditions 7.2, 7.4 to 7.8)

MRRR are taken from 40 CFR 63, Subpart ZZZZ. They are summarized as follows:

- Compliance date (PC 7.2)
- General compliance requirements (PC 7.4)
- Operation and monitoring requirements (PC 7.5)
- Continuous compliance requirements (PC 7.6)
- Recordkeeping requirements (PC 7.7)
- Requirements in 40 CFR 63, Subpart A (PC 7.8)

NATURAL GAS-FIRED BOILER

This is a new permit section.

New Permit Conditions 8.1 and 8.2 (NSPS)

The natural gas-fired boiler is subject to the requirements in 40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. They are applicable requirements in according to IDAPA 58.01.01.008.03.

The permittee is subject to reporting and recordkeeping requirements in 40 CFR 60, Subpart Dc (PC 8.2).

MRRR

No other MRRR are required in 40 CFR 60, Subpart Dc for the natural gas-fired boiler.

New Permit Conditions 8.3 to 8.26 (Boiler MACT)

The natural gas-fired boiler is subject to 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. The boiler is subject to work practice standards in the subpart (PC 8.5). The MRRR is specified in the subpart. The table of content of the subpart clearly outlines the MRRR. Detailed regulatory analysis, including the table of content of the subpart, can be found in Appendix B.

PLANER MILL

This is a new permit section. It is taken from the PTC issued on 5/10/2013. The facility has the option to vent gas streams from the planer shavings cyclone baghouse and the planer chip bin target box either inside or outside of the building.

New Permit Condition 9.1

As discussed in its underlying PTC, issued on 5/10/2013, the PM_{10} emissions limits in PC 9.1 only apply when emissions from the planer shavings cyclone baghouse and the planer chip bin target box are exhausted outside the building; when emissions from these two vents are exhausted inside the building the emissions limits do not apply. The limits are applicable requirements in according to IDAPA 58.01.01.008.03.

MRRR - (Permit Conditions 9.3 to 9.9)

Demonstrating compliance with the limits in PC 9.1 was specified in the underlying PTC issued on 5/10/2013. The following summarizes the methods used to demonstrate compliance:

- Install and operate the planer shavings bin baghouse in accordance with manufacturer recommendations. (PCs 9.3 and 9.4)
- Limit annual throughputs of the planner chip bin and the planer shavings bin. (PCs 9.5 and 9.6)
- Monitor and record throughput rates monthly and annually. (PCs 9.7 and 9.8)
- Monitor and record pressure drop across the planer shavings baghouse weekly. (PC 9.9)

New Permit Condition 9.2

PC 9.2 is visible emissions limit taken from the PTC issued on 5/10/2013. They are applicable requirements in according to IDAPA 58.01.01.008.03.

MRRR – (Permit Condition 9.10)

Demonstrating compliance with PC 9.2 was specified in the underlying PTC issued 5/10/2013.

- Monthly facility-wide see/no see inspection (PC 9.10)

INSIGNIFICANT ACTIVITIES

Table 10.1 of the permit is revised to remove Fire Water Pump from the insignificant list because it is subject to 40 CFR 63 Subpart ZZZZ and no longer qualify as an insignificant activity. Small Generators and Compressors are removed from the insignificant activity list because IFG currently only has Fire Water Pump engine. In addition, Small Generators and Compressors may be subject to federal regulations, such as 40 CFR 63, Subpart ZZZZ, 40 CFR 60, Subpart JJJJ that would disqualify them from being insignificant activities.

Description	**Insignificant Activities IDAPA 58.01.01.317.01(b)(i) Citation**
Bark Hog	IDAPA 58.01.01.317.01(b)(i)(30)
Covered Bark Conveyor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Screen (classifier), indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Sawmill Chipper, indoor	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Transfer to Fuel House	IDAPA 58.01.01.317.01(b)(i)(30)
Hog Fuel Truck Bin Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chipper and Screen	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Chip Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
Planer Shavings Bin Truck Loadout	IDAPA 58.01.01.317.01(b)(i)(30)
~~Fire Water Pump~~	~~IDAPA 58.01.01.317.01(b)(i)(30)~~
~~Small Generators and Compressors~~	~~IDAPA 58.01.01.317.01(b)(i)(6)~~

6.3 General Provisions

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

General Compliance, Duty to Comply

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

[IDAPA 58.01.01.322.15.a, 5/1/94; 40 CFR 70.6(a)(6)(i)]

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

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

[IDAPA 58.01.01.322.15.b, 5/1/94; 40 CFR 70.6(a)(6)(ii)]

General Compliance, Duty to Supplement or Correct Application

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

[IDAPA 58.01.01.315.01, 5/1/94; 40 CFR 70.5(b)]

Reopening, Additional Requirements, Material Mistakes, Etc.

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

[IDAPA 58.01.01.322.15.c, 5/1/94; IDAPA 58.01.01.386, 3/19/99; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

Reopening, Permitting Actions

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

[IDAPA 58.01.01.322.15.d, 5/1/94; 40 CFR 70.6(a)(6)(iii)]

Property Rights

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

[IDAPA 58.01.01.322.15.e, 5/1/94; 40 CFR 70.6(a)(6)(iv)]

Information Requests

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

[Idaho Code §39-108; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.f, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Information Requests, Confidential Business Information

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

[IDAPA 58.01.01.322.15.g, 5/1/94; IDAPA 58.01.01.128, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Severability

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

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]

Changes Requiring Permit Revision or Notice

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

[IDAPA 58.01.01.200-223, 4/2/08; IDAPA 58.01.01.322.15.i, 3/19/99; IDAPA 58.01.01.380-386, 7/1/02; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA

58.01.01. 383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385, 7/1/02; IDAPA 58.01.01.209.05, 4/11/06; 40 CFR 70.4(b)(14) and (15)]

Federal and State Enforceability

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

[IDAPA 58.01.01.322.15.j, 5/1/94; IDAPA 58.01.01.322.15.k, 3/23/98; Idaho Code §39-108; 40 CFR 70.6(b)(1), (2)]

Inspection and Entry

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

- Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;
- Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;
- Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
- As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108; IDAPA 58.01.01.322.15.l, 5/1/94; 40 CFR 70.6(c)(2)]

New Applicable Requirements

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

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.10.a.ii, 5/1/94; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

Fees

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

[IDAPA 58.01.01.387, 4/2/03; 40 CFR 70.6(a)(7)]

Certification

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

[IDAPA 58.01.01.322.15.o, 5/1/94; 40 CFR 70.6(a)(3)(iii)(A); 40 CFR 70.5(d)]

Renewal

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

[IDAPA 58.01.01.313.03, 4/5/00; 40 CFR 70.5(a)(1)(iii)]

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

[IDAPA 58.01.01.322.15.p, 5/1/94; 40 CFR 70.7(b)]

Permit Shield

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

- Such applicable requirements are included and are specifically identified in the Tier I operating permit; or
  - DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.
- The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).
- Nothing in this permit shall alter or affect the following:
  - Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;
  - The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;
  - The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and
  - The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

**[Idaho Code §39-108 and 112; IDAPA 58.01.01.122, 4/5/00;
IDAPA 58.01.01.322.15.m, 325.01, 5/1/94; IDAPA 58.01.01.325.02, 3/19/99;
IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03, 3/19/99; 40 CFR 70.6(f)]**

Compliance Schedule and Progress Reports

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

**[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.9, 5/1/94; IDAPA 58.01.01.314.10, 4/5/00;
40 CFR 70.6(c)(3) and (4)]**

Periodic Compliance Certification

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

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

[IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 70.6(c)(5)(iii) as amended, 62 Fed. Reg. 54900, 54946 (10/22/97); 40 CFR 70.6(c)(5)(iv)]

False Statements

The permittee may not make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

No Tampering

The permittee may not render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Semiannual Monitoring Reports.

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

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.322.08.c, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

Reporting Deviations and Excess Emissions

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

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

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.135, 4/11/06; 40 CFR 70.6(a)(3)(iii)]

Permit Revision Not Required, Emissions Trading

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

[IDAPA 58.01.01.322.05.b, 4/5/00; 40 CFR 70.6(a)(8)]

Emergency

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

[IDAPA 58.01.01.332.01, 4/5/00; 40 CFR 70.6(g)]

7. REGULATORY REVIEW

7.1 Attainment Designation (40 CFR 81.313)

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

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

The facility is classified as a major facility for Title V program, as defined by IDAPA 58.01.01.008.10.c, because it emits or has the potential to emit NOx, CO, and VOCs above the major source threshold of 100 tons-per-year. The facility is also classified as a major facility, as defined by IDAPA 58.01.01.008.10.a, because it emits or has the potential to emit methanol and acetaldehyde above the major source thresholds of 10 tons-per-year for any single HAP and 25 tons-per-year for any combination of HAP.

7.3 PSD Classification (40 CFR 52.21)

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility wide emissions of any criteria pollutant that exceed 250 T/yr. As part of this permit modification, limits are placed in the permit to clearly keep the PTE for CO below 250 T/yr. Permit Condition 4.3 limits the combined emissions of the hog fuel boiler and the natural gas-fired boiler (if used) so CO will not exceed 246 T/yr.

7.4 NSPS Applicability (40 CFR 60)

40 CFR 60, Subpart Dc ……………………….Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

The natural gas-fired boiler is subject to 40 CFR 60, Subpart Dc. The regulatory analysis, submitted by the applicant and reviewed by DEQ staff, can be found in Appendix B.

Non-applicability

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

The fire-water pump engine is not subject to this subpart because it was installed in 2004, prior to the model years listed in the regulation.

40 CFR 60, Subpart Db……………………….Standards for Industrial-Commercial-Institutional Steam Generating Units.

As discussed in the statement of basis for the the initial Tier I issued on May 2, 2008, the hog-fuel fired boiler is not subject to this subpart as discussed in the following:

The hog fuel boiler was originally built in 1977 and has not been modified or reconstructed, per NSPS definitions, since June 19, 1984, which is the trigger date for the NSPS Subpart Db. In accordance with this information, the hog fuel boiler is not subject to NSPS requirements of Subpart Db.

7.5 NESHAP Applicability (40 CFR 61)

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

7.6 MACT Applicability (40 CFR 63)

40 CFR 63, Subpart DDDD……………….….. Plywood and Composite Wood Products (PCWP)

As discussed in the statement of basis for the the initial Tier I issued on May 2, 2008, the dry kilns are subject to this subpart:

This subpart applies to lumber kilns at any facility that is major source of HAPs, so it applies to this facility. For kilns, only the initial notification requirements in Section 63.9(b) apply. On January 29, 2005, the facility notified EPA of applicability of subpart PCWP. Because the required notification has been made, no permit requirement will be written in this permit for the kilns.

40 CFR 63, Subpart ZZZZ…………………National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The fire-water pump engine is subject to this subpart. The regulatory analysis, submitted by the applicant and reviewed by DEQ staff, can be found in Appendix B.

40 CFR 63, Subpart DDDDD……………… National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

Boiler MACT reconsideration federal register notice was promulgated on January 31, 3013. The applicant is submitted Form FRA for this regulation during the review of the first facility draft permit. The regulatory analysis reviewed and revised by DEQ staff is included in Appendix B.

The hog fuel boiler and natural gas-fired boiler are subject to this subpart.

7.7 CAM Applicability (40 CFR 64)

The hog fuel-fired boiler is subject to CAM because it meets the following criteria:

- It is subject to PM_{10} emissions limits of 6.93 lb/hr and 30.4 T/yr.
- The boiler uses multiclone in series with EFB to achieve compliance with the above emissions limits.
- The potential pre-control PM_{10}/and PM emissions exceed 100 T/yr.

The permittee proposed the CAM requirements in the application, and they are reviewed and approved by DEQ staff. The detailed CAM plan and analysis can be found in Appendix B.

In accordance with 40 CFR 64.2(b), the hog fuel boiler is exempt from the CAM requirements for the filterable PM because the hog fuel boiler is subject to a filterable PM limit in 40 CFR 63, Subpart DDDDD.

7.8 Acid Rain Permit (40 CFR 72-75)

The facility is not subject to acid rain permit.

8. PUBLIC COMMENT

As required by IDAPA 58.01.01.364, a public comment period will be made available to the public.

9. EPA REVIEW OF PROPOSED PERMIT

As required by IDAPA 58.01.01.366, DEQ will provide the proposed permit to EPA Region 10 for its review and comment.

Appendix A - Facility Comments for Draft Permit

The following comments were received from the facility on July 10 and 25, 2013:

Facility Comment: Requested a few minor edits in sections 2, 4, 6, 7, Table 4.2, and Table 4.6. IFG requested DEQ to replace "section of §63" or "section of 63" with "40 CFR 63" and to replace "your" or "you" with "the permittee".

DEQ Response: The requested changes are made.

Facility Comment: Requested a testing date to be specified for CO testing in Permit Condition 4.11.

DEQ Response: The testing date is specified as "On or before July 30, 2014, the permittee shall conduct a compliance test…"

IFG conducted a source test on July 29, 2009. The test result was 0.58 lb CO/1,000 lb steam, which is 74% of the permit limit. According to the testing schedule in the underlying PTC, the upcoming source test date is specified as "on or before July 30, 2014."

Facility Comment: In Table 4.5 and Table 8.2, IFG added the tune-up requirement as the first line item to make it clearer. In both tables, IFG requested to leave in the options for annual or 5-year tune ups. IFG will need to see what the status of their boilers is at the compliance date.

DEQ Response: The requested changes are made.

Facility Comment: Table 4.5 includes the requirement for an energy audit. In the MACT regulation, the energy audit requirements are oddly placed inside Table 3 to the subpart. IFG proposed that Table 4.5 just referred to Table 3 to the subpart. Any user is going to refer directly to the regulation rather than relying on just the permit.

DEQ Response: The requested changes are not made because they are apply to the hog fuel boiler. The definition of energy assessment in 40 CFR 63.7575 is added to the table for clarity.

Facility Comment: In Table 4.5, IFG also requested to refer the work practices in Table 3 to the subpart rather than put the requirements in the permit. This is for simplicity and because EPA knows the startup work practices are unworkable and need to be changed.

DEQ Response: The requested changes are not made. The permit is based on current rules. Any changes to the rules in the future are already covered in facility-wide condition 3.28. In addition, an alternative work practice may be approved by EPA according to 40 CFR 63.7525(c) that is included in the permit as Permit Condition 4.33.

Facility Comment: IFG made notes about applicability in the first column of Table 4.5 to make sure it is clear.

DEQ Response: The initial tune-up requirement is added in PC 4.37 as required in 40 CFR 63.7510(e) and is not included in Table 4.5 (Table 3 to the Subpart) to avoid confusion.

Facility Comment: Requested to delete CPMS and PM CPMS that are not applicable to the hog fuel boiler from Permit Condition 4.35.

DEQ Response: PM CPMS is removed because they boilers are not using PM CPMS. CPMS is kept because the hog fuel boiler uses CPMS (i.e., steam rate monitor, oxygen analyzer) to demonstrate compliance with the operating limits.

Facility Comment: Requested to put the compliance date upfront for clarity in Permit Condition 4.37.

DEQ Response: The change is made. 40 CFR 63.7510(e) regarding compliance date is put upfront as Permit Condition 4.37. 40 CFR 63.7510(a) through (d) are followed after that as Permit Conditions 4.38 through 4.41.

Facility Comment: Requested to leave out Table 5 to the subpart and Table 6 to the subpart from the permit in Section 4 for the hog fuel boiler. Requested to cite the reference in the regulations and leave out the details for Section 4 for the hog fuel boiler and Section 8 for the natural gas-fired boiler.

DEQ Response: Requested changes are not made. A lot of time has been spent to identify the requirements that specifically apply to the facility. These requirements are included in the permit, including the tables to the subpart. For title V operating permit, EPA has requested that the permit includes all the applicable requirements in details.

Facility Comment: Request to change from "for 50 hours per year is prohibited" in 40 CFR 63.6640(f) to "for more than 50 hours year is prohibited".

DEQ Response: 40 CFR 63.6640(f) reads as follows:

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

The change is not made because the phrase was the same as that in the regulation. I would interpret "for 50 hours per year is prohibited" as "for 50 hours or more per year is prohibited."

Facility Comment: In Natural Gas-fired Boiler section, the facility requested to change 46 MMBtu/hr to 50 MMBtu/hr under Summary Description.

DEQ Response: The change is not made because the emissions inventory (EI) was calculated based on 46 MMBtu/hr for natural gas-fired boiler.

Appendix B – Regulatory Analysis

Appendix B.1 - 40 CFR 60, Subpart Dc

e-CFR Data is current as of November 29, 2012

Subpart Dc—Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraphs (d), (e), (f), and (g) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/h)) or less, but greater than or equal to 2.9 MW (10 MMBtu/h).

The IFG Natural Gas boiler has a heat input capacity greater than 10 MMBtu/h and less than 100 MMBtu/h. It was built after June 9, 1989. Therefore, NSPS Subpart Dc applies to this boiler.

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

40 CFR 60.48c(a)(4) is administered by EPA, not the State of Idaho. But this subpart has been delegated to DEQ.

(c) Steam generating units that meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO_2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

IFG has no plans to use the natural gas boiler for combustion research. If this changes, IFG will notify EPA and the State of Idaho.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

IFG has no plans to use the natural gas boiler for combustion research. If this changes, IFG will notify EPA and the State of Idaho.

(e) Affected facilities (*i.e.* heat recovery steam generators and fuel heaters) that are associated with stationary combustion turbines and meet the applicability requirements of subpart KKKK of this part are not subject to this subpart….

The IFG Natural Gas boiler is not associated with a stationary combustion turbine.

(f) Any affected facility that meets the applicability requirements of and is subject to subpart AAAA or subpart CCCC of this part is not subject to this subpart.

This provision does not apply to the IFG Natural Gas Boiler.

(g) Any facility that meets the applicability requirements and is subject to an EPA approved State or Federal section 111(d)/129 plan implementing subpart BBBB of this part is not subject to this subpart.

This provision does not apply to the IFG Natural Gas Boiler.

(h) Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_x standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable.

This provision does not apply to the IFG Natural Gas Boiler.

(i) Temporary boilers are not subject to this subpart.

From § 60.41c Definitions: Temporary boiler means a steam generating unit that combusts natural gas or distillate oil with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A steam generating unit is not a temporary boiler if any one of the following conditions exists: (1) The equipment is attached to a foundation. (2) The steam generating unit or a replacement remains at a location for more than 180 consecutive days. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period. (3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year. (4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

IFG does not intend for the Natural Gas Boiler temporary, it could remain at the mill for more than 180 days.

§ 60.42c Standard for sulfur dioxide (SO2).

The IFG Natural Gas Boiler will only burn natural gas. This section does not contain applicable requirements.

§ 60.43c Standard for particulate matter (PM).

The IFG Natural Gas Boiler will only burn natural gas. This section does not contain applicable requirements.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

The IFG Natural Gas Boiler will only burn natural gas. This section does not contain applicable requirements.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

The IFG Natural Gas Boiler will only burn natural gas. This section does not contain applicable requirements.

§ 60.46c Emission monitoring for sulfur dioxide.

The IFG Natural Gas Boiler will only burn natural gas. This section does not contain applicable requirements.

§ 60.47c Emission monitoring for particulate matter.

The IFG Natural Gas Boiler will only burn natural gas. This section does not contain applicable requirements.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction and actual startup, as provided by § 60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under § 60.42c, or § 60.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions.

IFG will submit the required notifications to EPA, with a copy to Idaho DEQ, as required in § 60.7 of this part.

(b) The owner or operator of each affected facility subject to the SO_2 emission limits of § 60.42c… The IFG Natural Gas Boiler will only burn natural gas. This section does not apply.

(c) In addition to the applicable requirements in § 60.7, the owner or operator of an affected facility subject to the opacity limits… The IFG Natural Gas Boiler will only burn natural gas. This section does not apply.

(g)(1) Except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

(2) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in § 60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

IFG elects to record and maintain records of the amount of each fuel combusted during each calendar month.

(3) As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in § 60.42C to use fuel certification to demonstrate compliance with the SO2 standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

Appendix B.2 - 40 CFR 63, Subpart ZZZZ

Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions … (a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. ***The Chilco fire-water pump engine is a diesel-fired (compression ignition) RICE. IFG's Chilco facility is a Major Source of HAP.***

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source… (ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006. ***The Chilco fire-water pump engine is an affected source. It is an existing stationary RICE with a site rating of 150 brake HP, and was installed in 2004.***

§ 63.6595 When do I have to comply with this subpart?

(a) Affected sources. (1) If you have … an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions… you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013.

§ 63.6602 What emission limitations must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart which apply to you.

Table 2c to Subpart ZZZZ of Part 63—

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. **Emergency stationary CI RICE** and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

The Chilco fire-water pump engine is an emergency engine. It is only used for fire suppression. It is tested regularly to ensure readiness.

[1] If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2] Sources have the option to utilize an oil analysis program as described in § 63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3] Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

IFG would like to have this option. However it might turn out that changing the oil is easier than fulfilling the testing requirements.

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

The above requirements do apply to the affected source, as do all applicable portions of the regulation.

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

The non-resettable hours meter is required for the Chilco firewater pump. IFG will have a maintenance and compliance plan which will be available for review onsite.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

IFG would like to have this option. However it might turn out that changing the oil is easier than fulfilling the testing requirements..

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

Table 6 to Subpart ZZZZ of Part 63

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

These apply. IFG will have a maintenance plan which will be available for review onsite.

IFG must comply with the following conditions for operation of the emergency fire-water pump engine.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions…you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section.
(i) There is no time limit on the use of emergency stationary RICE in emergency situations.
(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year.
(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing.

§ 63.6645 What notifications must I submit and when?
(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP**, an existing stationary emergency RICE,** or an existing stationary RICE that is not subject to any numerical emission standards.
According to 63.6645(5), notifications are not required for an existing stationary emergency CI RICE. IFG understands that notification is not required for the fire-water pump engine.

§ 63.6650 What reports must I submit and when?
(a) You must submit each report in Table 7 of this subpart that applies to you.
No reports in Table 7 apply.

Sec. 63.6655 What records must I keep?

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

Table 6

For each . . .	**Complying with the requirement to . . .**	**You must demonstrate continuous compliance by . . .**
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.

The requirements apply. IFG will have a compliance plan that itemizes applicable requirements in a user-friendly format.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(2) An existing stationary emergency RICE.

IFG will develop a maintenance plan before the compliance date of May 3, 2013.

IFG must keep records of engine operation for 5 years, as described below.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the nonresettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1).

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

Appendix B.3 - 40 CFR 64 (CAM)

Minor changes are made to IFG's proposed CAM. Refer to the permit for details.

MONITORING APPROACH SUBMITTAL

Background		
5. Emissions Unit	Description (type of emission point): Hog Fuel Boiler	Identification (emission point number): Hog Fuel Boiler, EU#1
6. Applicable Regulation, Emission Limits, and Monitoring Requirements	Applicable regulation citation: IDAPA 58.01.01.677 /PTC NO. P-050116 Tier I T1-2009.0123	Pollutant: PM Emission limit: 0.200 gr/dscf @ 8% oxygen Pollutant: PM Emission limit: 6.93 lb/hr and 30.4 tpy Monitoring requirements: NSPS does not apply, so there are no regulatory monitoring requirements.
7. Control Technology	Brief description: Multiclone, followed by an electrified filter bed (EFB) with a media-cleaning baghouse.	

Table 1. Monitoring Approach

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator Description	Ionizer Current	Ionizer Voltage	Filter Bed Voltage
Measurement Approach	Continuous current monitor (ammeter) with operator readout for each tower.	Continuous voltage monitor (voltmeter) with operator readout for each tower.	Continuous voltage monitor (voltmeter) with operator readout for each tower.
II. Indicator Range (Quality improvement plan threshold optional)	0 to 2.5 milliamps (mA) An excursion is defined as ionizer current outside the above range. Excursions trigger an inspection, corrective action and reporting requirements.	10 to 40 kilovolts (kV) An excursion is defined as ionizer voltage outside the above range. Excursions trigger an inspection, corrective action and reporting requirements.	10 to 40 kilovolts (kV) An excursion is defined as ion filter bed voltage outside the above range. Excursions trigger an inspection, corrective action and reporting requirements.
III. Performance Criteria	———	———	———
A. Data Representativeness	The current is measured using instrumentation provided by the EFB manufacturer and used as per design.	The voltage is measured using instrumentation provided by the EFB manufacturer and used as per design.	The voltage is measured using instrumentation provided by the EFB manufacturer and used as per design.
B. Verification of Operational Status	Verify that the ammeter is properly calibrated following any repair or maintenance.	Verify that the voltmeter is properly calibrated following any repair or maintenance.	Verify that the voltmeter is properly calibrated following any repair or maintenance.
C. QA/QC Practices and Criteria	Confirm that ammeter reads zero when the EFB is not operating.	Confirm that voltmeter reads zero when the EFB is not operating.	Confirm that voltmeter reads zero when the EFB is not operating.
D. Monitoring Frequency	Record hourly. Monitoring is complete if 20 of 24 hours are recorded.	Record hourly. Monitoring is complete if 20 of 24 hours are recorded.	Record hourly. Monitoring is complete if 20 of 24 hours are recorded.
E. Data Collection Procedures	Data is recorded on daily log forms and maintained on-site for 5 years.	Data is recorded on daily log forms and maintained on-site for 5 years.	Data is recorded on daily log forms and maintained on-site for 5 years.
F. Averaging Period	Current reading is instantaneous at the time recorded.	Voltage reading is instantaneous at the time recorded.	Voltage reading is instantaneous at the time recorded.

Table 1. Monitoring Approach, continued

	Indicator No. 4	Indicator No. 5	Indicator No. 6
I. Indicator Description	Filter Bed Current	Filter Bed Temperature	Media Baghouse Pressure Drop
Measurement Approach	Continuous current monitor (ammeter) with operator readout for each tower.	Filter bed temperature is measured with a thermocouple at the beginning of the outlet plenum, where the gas streams from the two towers combine.	Pressure sensors are located at the inlet and outlet of the baghouse. Pressures are compared using a differential pressure gauge.
II. Indicator Range (Quality improvement plan threshold optional)	0 to 0.35 milliamps (mA) An excursion is defined as ion filter bed current outside the above range. Excursions trigger an inspection, corrective action and reporting requirements.	$\geq$ 150 ^{o}F An excursion is defined as ion filter bed temperature outside the above range. Excursions trigger an inspection, corrective action and reporting requirements.	0 – 6.0 inches water column (" w.c.) An excursion is defined media baghouse pressure drop outside the above range. Excursions trigger an inspection, corrective action and reporting requirements.
III. Performance Criteria	———	———	———

A. Data Representativeness	The current is measured using instrumentation provided by the EFB manufacturer and used as per design.	Temperature equalizes within the EFB towers and gas exiting the filter beds has essentially the same temperature as the beds.	Pressure differential (pressure drop) across the baghouse may indicate air flow is bypassing the bags (low ΔP) or is obstructed (high ΔP).
B. Verification of Operational Status	Verify that the ammeter is properly calibrated following any repair or maintenance.	Verify that the thermocouple is properly calibrated following any repair or maintenance.	Verify that the pressure sensors are in place
C. QA/QC Practices and Criteria	Confirm that ammeter reads zero when the EFB is not operating.	Confirm that thermocouple temperature approaches ambient temperature when the EFB is not operating.	Confirm that the pressure differential gauge reads zero when air is not flowing through the baghouse.
D. Monitoring Frequency	Record hourly. Monitoring is complete if 20 of 24 hours are recorded.	Record hourly. Monitoring is complete if 20 of 24 hours are recorded.	Record once per day.
E. Data Collection Procedures	Data is recorded on daily log forms and maintained on-site for five years.	Data is recorded on daily log forms and maintained on-site for five years.	Data is recorded on daily log forms and maintained on-site for five years.
F. Averaging Period	Current reading is instantaneous at the time recorded.	Temperature reading is instantaneous at the time recorded.	Pressure differential reading is instantaneous at the time recorded.

Table 1. Monitoring Approach, continued

	Indicator No. 7		
I. Indicator Description	Visible Emissions		
Measurement Approach	Observation of visible emissions		
II. Indicator Range (Quality improvement plan threshold optional)	If visible emissions are present, corrections are made.		
III. Performance Criteria	———		
A. Data Representativeness	Under normal operations, emissions from the baghouse are not visible. If visible emissions are noted, it may indicate operational problems with the baghouse.		
B. Verification of Operational Status	Not applicable.		
C. QA/QC Practices and Criteria	Not applicable.		
D. Monitoring Frequency	Quarterly.		
E. Data Collection Procedures	Quarterly observations are included in the quarterly monitoring report.		
F. Averaging Period	Visible emissions observations are instantaneous at the time made.		

Justification	Present justification for selection of monitoring approach(es) and indicator range(s): **Justification for Indicator 1:** The current on the ionizer provides an indicator of the voltage. A decrease in current could indicate a malfunction, such as a buildup of PM or condensed hydrocarbons on the ionizer. **Justification for Indicator 2:** The voltage indicates that a corona is formed and is generating ions for charging particles. **Justification for Indicator 3:** The voltage on the gravel must be maintained so charged PM is attracted to the gravel. A decrease in voltage could indicate a malfunction, such as a short or a buildup of PM or condensed hydrocarbons on the gravel. **Justification for Indicator 4:** A sudden increase in bed current with no corresponding increase in bed voltage or with a bed voltage at zero indicates a short in the filter bed. **Justification for Indicator 5:** Filter bed temperature needs to be high enough to ensure that water in the gas stream does not condense. Moisture condensation in the filter bed can result in an electrical short, and contribute the buildup of hydrocarbon glaze on the ionizer or the gravel. This buildup interferes with the corona charging of the ionizer and the electrode charging of the filter bed. **Justification for Indicator 6:** Pressure differential from the inlet to the outlet of the baghouse (pressure drop) is an indicator of resistance within the baghouse. If the pressure drop is below the normal operating range, it may indicate a leak allowing air to bypass the filter bags. If the pressure drop is above the normal operating range, it may indicate that the flow has become obstructed in some way. **Justification for Indicator 7:** Under normal operations, emissions from the baghouse are not visible. Therefore, visible emissions may indicate a problem within the baghouse.

Appendix B.4 - 40 CFR 63, Subpart DDDDD

Based on IFG's analysis submitted on 7/25/2013 and reviewed and revised by DEQ staff. The applicable requirements are highlighted followed with the explanations in green and underlined.

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of September 19, 2013

Title 40: Protection of Environment
PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES (CONTINUED)

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

---

SOURCE: 76 FR 15664, Mar. 21, 2011, unless otherwise noted.

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

IFG operates industrial boilers, the hog fuel boiler and the natural gas-fired boiler, at the Chilco sawmill and is subject to this subpart. The Chilco sawmill is a major source of HAP emissions.

[78 FR 7162, Jan. 31, 2013]

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

The natural gas boiler is a new boiler because it was first brought onto the facility in 2012.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

The Chilco wood-fired (hog fuel) boiler is an affected source and an existing boiler.

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

Does not apply.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA-453/R-01-005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

IFG- Chilco does not have any boilers or process heaters that are not subject to this subpart.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

EDITORIAL NOTE: At 78 FR 7162, Jan. 31, 2013, § 63.7491 was amended by revising paragraph (n). However, there is no paragraph (n) to be revised.

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

The natural gas boiler is a new source and must comply with this subpart by January 31, 2013.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

The hog fuel boiler is an existing source and must comply with this subpart by January 31, 2016.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

Does not apply to IFG.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

For both boilers, IFG notification is due no later than 120 days after January 31, 2013 in accordance with 40 CFR 63.7545(b) that is May 31, 2013.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

Does not apply.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

Does not apply.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

Does not apply.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7162, Jan. 31, 2013]

Emission Limitations and Work Practice Standards

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

The IFG-Chilco hog fuel boiler falls into this subcategory.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

The IFG-Chilco natural gas-fired boiler falls into this subcategory.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

Table 1 is for new boilers. It contains no emission limits for new boilers burning gas 1 fuel, so there are no emission limits that apply to the natural gas-fired boiler.

Table 2 is for existing boilers. It contains the applicable emission limits applying to the hog fuel boiler. The HCl and mercury limits are new. The MACT PM limit is lower than the PM_{10} permit limit, but only includes filterable PM.

Table 3 contains applicable work practice standards for the hog fuel boiler and the natural gas boiler. The hog fuel boiler will have to have annual tune-ups and a one-time energy assessment. If the natural gas boiler is retained, it will also have to have annual tune-ups. If the boiler installs a continuous oxygen trim system, it will only be subject to 5-year tune-ups. IFG has requested to keep five years tune-up requirements in the permit in case IFG decides to install a continuous oxygen trim system that maintains an optimum air to fuel ratio to the boiler(s) in the future. A note "At the time of the permit issuance, the hog fuel boiler/natural gas-fired boiler does not have a continuous oxygen trim system" is added to the permit under the requirement for both boilers.

Only the hog fuel boiler is subject to the startup and shutdown requirements in Items 5 and 6 of Table 3. The startup requirements in Item 5 of Table 3 are not compatible with the hog fuel boiler lighting procedures because they don't allow wood to be used during startup. If EPA doesn't correct this requirement, IFG will need to apply for an alternative work practice. Since it is an applicable requirement, it is still included in the permit. 40 CF 63.7500(b) is included in the permit regarding EPA approval of an alternative to the work practice standards.

Refer to Tables 2 and 3 to the subpart for details.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

Table 4 contains operating limits applicable to the hog fuel boiler. MACT limits the opacity to 10% (daily block average), while the permit allows 20% over a 3-minute average. MACT requires that the boiler can only be operated at 110% of the source test level, while the state usually allow for 120%.

More details can be found in Table 4 to the subpart.

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

This applies to both boilers.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

This applies to both boilers. 40 CFR 63.6(g) is not spelled out in the permit. IFG can refer to CFR for the details when needed.

IFG may need to request EPA approval for an alternative to the startup work practice standards contained in Table 3 item 5 for the hog fuel boiler.

(c) Limited-use boilers and process heaters must complet…Does not apply. IFG does not ask for using their boilers as limited-use boilers.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour…Does not apply.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour…Does not apply.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

The emission limits on the hog fuel boiler do not apply during startup and shutdown. The hog fuel boiler complies only with Table 3 to this subpart during startup and shutdown.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

IFG is aware of this section and will follow the requirements should it become necessary. This may not happen often. The details are not included in permit but referred in the permit.

[78 FR 7163, Jan. 31, 2013]

General Compliance Requirements

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

IFG will comply with all the emission limits, work practice standards and operating limits in this subpart, as summarized in Tables 2, 3 and 4.

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

This requirement applies to the hog fuel boiler. IFG will use source testing and fuel analysis as appropriate to demonstrate compliance.

IFG chooses to comply with filterable PM limit rather than alternative TSM limit.

COMS is for opacity operating limit as required in Table 4 to the subpart.

After CO performance test, IFG shall keep minimum Oxygen level (an operating limit) using Oxygen analyzer system that is a CPMS.

After performance test for an emissions limit of this subpart, IFG shall keep boiler steam production rate (an operating limit) not to exceed 110% of the steam production rate obtained during the most recent performance test. A continuous steam rate monitor is a CPMS.

As defined in 40 CFR 63.2, Continuous monitoring system (CMS) is a comprehensive term that may include, but is not limited to, continuous emission monitoring systems, continuous opacity monitoring systems, continuous parameter monitoring systems, or other manual or automatic monitoring that is used for demonstrating compliance with an applicable regulation on a continuous basis as defined by the regulation)

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

The hog fuel boiler is subject to this requirement.

After CO performance test, IFG shall keep minimum Oxygen level (an operating limit) using Oxygen analyzer system that is a CPMS.

After performance test for an emissions limit, IFG shall keep boiler steam production rate (an operating limit) not to exceed 110% of the steam production rate obtained during the most recent performance test. A continuous steam rate monitor is a CPMS.

In accordance with 40 CFR 63..2, *Continuous parameter monitoring system* (CPMS) means the total equipment that may be required to meet the data acquisition and availability requirements of this part, used to sample, condition (if applicable), analyze, and provide a record of process or control system parameters.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7164, Jan. 31, 2013]

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

This applies to the hog fuel boiler. IFG will comply.

This does not apply to the natural gas-fired boiler because it is not subject to any emissions limits.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

Neither of the boilers is subject to this requirement because they burn a single type of fuel.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

This applies to the hog fuel boiler. IFG will establish steam production operating limits based on the steaming rate during the PM MACT compliance test. IFG will establish a minimum oxygen operating limit based on the oxygen levels during the CO compliance test. If IFG installs/converts the oxygen analyzer to an oxygen trim system, the trim system will be set to the required oxygen level. If IFG retains the oxygen analyzer only, IFG will track rolling 30-day oxygen averages to determine compliance, as described in Table 8.

This does not apply to natural gas-fired boiler because it is not subject to any emissions and operation limits.

(4) Conduct CMS performance evaluations according to § 63.7525.

The hog fuel boiler is subject to this requirement.

IFG will need to install CMS that are COMS, oxygen analyzer (won't be required if installing an oxygen trim system), and hog fuel boiler steam production rate monitor.

This does not apply to the natural gas-fired boiler because the boiler is not required to have CMS.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

For hog fuel boiler, IFG will use either fuel testing or source testing for HCl and mercury compliance. PM testing will be used as allowed for TSM compliance demonstration.

The natural gas-fired boiler is not subject to these requirements because it is not subject to any emissions limits.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

IFG will source test the hog fuel boiler for CO. The natural gas-fired boiler is not subject to the requirement because it is not subject to any emissions limits.

(d) *If your boiler* or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

IFG will source test the hog-fuel boiler for PM. The natural gas-fired boiler is not subject to the requirement because it is not subject to any emissions limits.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

The hog fuel boiler is an existing boiler and subject to initial compliance demonstration, tune-up, and one-time energy assessment. The hog-fuel boiler initial source tests and fuel analysis are due by July 29, 2016 (180 days after the compliance date). The initial tune-up and one-time energy assessment are due by January 31, 2016.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

This does not apply to the natural gas-fired boiler because the natural gas boiler is a new boiler, but is not subject to any emissions limits.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

The natural gas-fired boiler is a new affected source and subject to this requirement. The initial tune-up due date is January 31, 2014 for the natural gas-fired boiler.

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

This may not happen often. The details are not included in permit but referred in the permit.

40 CFR 63.2 *Effective date* means:

(1) With regard to an emission standard established under this part, the date of promulgation in the FEDERAL REGISTER of such standard;

The effective date of the rule is January 31, 2013.

[78 FR 7164, Jan. 31, 2013]

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

IFG will schedule source tests as required for the hog fuel boiler.

This does not apply to the natural gas-fired boiler as the boiler is not subject to any emissions limits.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

This applies to the hog fuel boiler. This provision is similar to the current permit. IFG will schedule source tests as required under the rule.

IFG will comply with the maximum chloride and maximum mercury if stack testing is conducted for HCl and mercury as necessary according to the subpart.

Emission averaging does not apply. TSM requirement does not apply because IFG has chosen to comply with PM limit.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

This provision is similar to the current permit. IFG will schedule source tests as required under the rule.

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

This applies to both the hog fuel fired boiler and natural gas-fired boiler. IFG will schedule boiler tune-ups as required under the rule.

Annual tune-up is for boilers without a continuous oxygen trim system that maintains an optimum air to fuel ratio. None of the boilers has the system at the time of the permit issuance.

IFG may install a continuous oxygen trim system that maintains an optimum air to fuel ratio on their boiler in the futures. For boilers with continuous oxygen trim system that maintains an optimum air to fuel ratio, they are subject to a 5-year tune-up schedule.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

If IFG choses to use fuel analysis, the sampling program will comply with the schedule specified in the section.

This applies to the hog fuel boiler but does not apply to the natural gas-fired boiler because the natural gas-fired boiler is not subject to HCl and mercury limits.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

For hog fuel boiler, IFG will report results of performance tests in the time frame as specified in the section. Boiler operating levels during the source tests will be documented. The associated fuel analyses to the performance tests are not required for the hog fuel boiler. Refer to discussions in the previous sections.

The natural gas-fired boiler is not subject to test and fuel analysis requirements and is not subject to this reporting requirement.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in

§ 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

This applies if situation as described above happens to the hog fuel boiler or natural gas-fired boiler.

The natural gas-fired boiler is only subject to the tune-up requirement.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

Does not apply.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

IFG does not plan to use a CO CEMS.

[78 FR 7165, Jan. 31, 2013]

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

This only applies to the hog fuel boiler. Source test protocols will be submitted as required and equipment will be operated during testing as required by the EPA reference methods.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

Source tests will be performed following the appropriate EPA reference methods listed in Table 5.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

This only applies to the hog fuel fired boiler.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

This only applies to the hog fuel fired boiler.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A-7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

This only applies to the hog fuel fired boiler.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

This only applies to the hog fuel fired boiler. IFG does not have CEMS.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7166, Jan. 31, 2013]

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

This applies to the hog fuel boiler. IFG has chosen to comply with PM limit rather than TSM limit.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later

than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

The section applies to the hog fuel boiler and does not apply to the natural gas-fired boiler. (gas 1).

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

The section applies to the hog fuel boiler and does not apply to the natural gas-fired boiler. (gas 1).

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

IFG will prepare fuel samples as required. Details will be provided in the fuel monitoring plan.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

IFG will follow the specified procedures and use the required calculations. Equations 7 and 8 should be Equations 16 and 17.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas

plants.

Does not apply.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

Does not apply.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

Does not apply.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

Does not apply.

[78 FR 7167, Jan. 31, 2013]

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average….

IFG does not have more than one existing boiler in any subcategory. This section does not apply.

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) – (7)

IFG has an oxygen analyzer system in place and does not intend to install a CO CEMS. Therefore, paragraphs (a)(1) through (7) of 63.7525 do not apply.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) – (8)…

Does not apply.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

IFG is required to install and operate a COMS on the hog fuel boiler's EFB stack. IFG will install the COMS as required before the January 31, 2016 compliance date. IFG will comply with the requirements.

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

Does not apply.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

(5) You must record the results of each inspection, calibration, and validation check.

(1) – (5) apply because they are required under 40 CFR 63.7525(e)

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

Apply to the steam rate monitor of the hog fuel boiler.

(f) – (m)

Does not apply.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7171, Jan. 31, 2013]

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

This applies to hog fuel boiler.

(1)…

(2)…

The associated fuel analysis with the performance test is exempt for the boiler burns a single fuel type (hog fuel) in accordance with 40 CFR 63.7510(a)(2)(i). Therefore, (1) and (2) do not apply.

(3)…

IFG does not choose the alternative TMS limit; therefore, (3) does not apply.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

This applies to the hog fuel boiler.

(i) For a wet acid gas scrubber…Does not apply.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS…

Does not apply because IFG does not use PM CPMS.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber…Does not apply.

(iv) For a dry scrubber... Does not apply.

(v) For activated carbon injection... Does not apply.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection ... Does not apply.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

This applies to the hog fuel boiler.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS ... Does not apply.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

This does not apply because the hog fuel boiler burns one fuel type, woodwaste.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to §

63.7521, in units of pounds per million Btu. SD is calculated as the sample standard deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

This applies to the hog fuel boiler if IFG chooses to demonstrate compliance with the HCl and mercury limits through fuel analysis.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

This applies to the hog fuel boiler if IFG chooses to demonstrate compliance with the HCl limit through fuel analysis.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

This applies to the hog fuel boiler if IFG chooses to demonstrate compliance with the mercury limit through fuel analysis.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the

TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n}(TSM90i \times Qi) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of “1” for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

This does not apply to the hog fuel boiler because IFG chooses to comply with the PM limit and not the TSM limit.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

This applies the natural gas-fired boiler. It is in a unit designed to burn gas 1 subcategory.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

This applies the hog fuel boiler. This does not apply to the natural gas-fired boiler because the natural gas-fired boiler is not subject to the energy assessment requirement.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

This applies to the both boilers.

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

Does not apply.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

This applies to the hog fuel boiler as it is subject to limits in Table 2 to the subpart.

This does not apply to the natural gas-fired boiler.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) …

(2)…

(3)…

Does not apply.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7174, Jan. 31, 2013]

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html* .

This can be used for the hog fuel boiler. IFG may choose to use efficiency credits at Chilco, and will follow all the requirements of this section.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.,* fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark

to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual}\right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

This can be used for the hog fuel boiler. IFG may choose to use efficiency credits at Chilco, and will follow all the requirements of this section.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7178, Jan. 31, 2013]

Continuous Compliance Requirements

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

This applies to the hog fuel boiler and does not apply to the natural gas-fired boiler.

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

This applies to the hog fuel boiler. This does not apply to the natural gas-fired boiler because the natural gas-fired boiler is only subject to a tune up requirement and is not required to use monitoring system.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

This applies to the hog fuel boiler.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

This applies to the hog fuel boiler.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7179, Jan. 31, 2013]

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

This does not apply because fuel analysis associated with performance test is exempt for hog fuel boiler in accordance with 40 CFR 63.7510(a)(2).

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel…

Does not apply. The hog fuel boiler only burns wood and bark, and IFG does not foresee ever using a different fuel type.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels…

Does not apply. The hog fuel boiler only burns wood and bark, and IFG does not foresee ever using a different fuel type.

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel…

Does not apply. The hog fuel boiler only burns wood and bark, and IFG does not foresee ever using a different fuel type.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels…

Does not apply. The hog fuel boiler only burns wood and bark, and IFG does not foresee ever using a different fuel type.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system…

Does not apply.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart…

Does not apply.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

IFG does not intend to use this provision of the rule. IFG does not have the listed CMS.

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

This applies to the hog fuel boiler and the natural gas-fired boiler.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance… Does not apply.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

If IFG installs a continuous oxygen trim system that maintains an optimum air to fuel ratio, they will switch to the 5-year tune up schedule for the hog fuel boiler.

At the time of the permit issuance, neither of the boilers has a continuous oxygen trim system that maintains an optimum air to fuel ratio

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i)

and (ii) of this section. Does not apply.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data. Does not apply.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F. Does not apply.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan. Does not apply.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data. Does not apply.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F. Does not apply.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels… Does not apply. IFG has chosen to comply with PM limit rather than TSM limit.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel… Does not apply. IFG has chosen to comply with PM limit rather than TSM limit.

(i) …

(ii)…

(iii)…

Does not apply. IFG has chosen to comply with PM limit rather than TSM limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS …

(i) - (iii) …

Does not apply.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) – (vii)…

Does not apply. IFG chooses to conduct performance test.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

This applies to the hog fuel boiler as it is subject to emissions limits and operating limits in Tables 2 and 4.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory…

(1) – (4)…

Does not apply. The natural gas-fired boiler, the unit designed to burn gas 1 subcategory, is not subject to a mercury limit.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

This applies to the hog fuel boiler. The work practice standards in item 5 of Table 3 will not work for starting the hog fuel boiler. If EPA doesn't correct this item, IFG may apply to EPA a alternative work practice.

[78 FR 7179, Jan. 31, 2013]

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

IFG Chilco does not intend to use the emissions averaging provision because there are not more than one boiler in any one subcategory.

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

IFG conducted the analysis that is listed in the following:

> § 63.7(b) *Notification of performance test.* (1) The owner or operator of an affected source must notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin to allow the Administrator, upon request, to review and approve the site-specific test plan required under paragraph (c) of this section and to have an observer present during the test.
>
> IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test. Only 30-day notice is required for Idaho air permit compliance tests.

This applies to the hog fuel boiler and not the natural gas-fired boiler that is not subject to any emissions limits.

§ 63.7(c) *Quality assurance program.* (1) The results of the quality assurance program required in this paragraph will be considered by the Administrator when he/she determines the validity of a performance test.

(2)(i) *Submission of site-specific test plan.* Before conducting a required performance test, the owner or operator of an affected source shall develop and, if requested by the Administrator, shall submit a site-specific test plan to the Administrator for approval. The test plan shall include a test program summary, the test schedule, data quality objectives, and both an internal and external quality assurance (QA) program. Data quality objectives are the pretest expectations of precision, accuracy, and completeness of data.

(ii) The internal QA program shall include, at a minimum, the activities planned by routine operators and analysts to provide an assessment of test data precision; an example of internal QA is the sampling and analysis of replicate samples.

(iii) The performance testing shall include a test method performance audit (PA) during the performance test. The PAs consist of blind audit samples supplied by an accredited audit sample provider and analyzed during the performance test in order to provide a measure of test data bias. Gaseous audit samples are designed to audit the performance of the sampling system as well as the analytical system and must be collected by the sampling system during the compliance test just as the compliance samples are collected. If a liquid or solid audit sample is designed to audit the sampling system, it must also be collected by the sampling system during the compliance test. If multiple sampling systems or sampling trains are used during the compliance test for any of the test methods, the tester is only required to use one of the sampling systems per method to collect the audit sample. The audit sample must be analyzed by the same analyst using the same analytical reagents and analytical system and at the same time as the compliance samples. Retests are required when there is a failure to produce acceptable results for an audit sample. However, if the audit results do not affect the compliance or noncompliance status of the affected facility, the compliance authority may waive the reanalysis requirement, further audits, or retests and accept the results of the compliance test. Acceptance of the test results shall constitute a waiver of the reanalysis requirement, further audits, or retests. The compliance authority may also use the audit sample failure and the compliance test results as evidence to determine the compliance or noncompliance status of the affected facility. A blind audit sample is a sample whose value is known only to the sample provider and is not revealed to the tested facility until after they report the measured value of the audit sample. For pollutants that exist in the gas phase at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in air or nitrogen that can be introduced into the sampling system of the test method at or near the same entry point as a sample from the emission source. If no gas phase audit samples are available, an acceptable alternative is a sample of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. For samples that exist only in a liquid or solid form at ambient temperature, the audit sample shall consist of an appropriate concentration of the pollutant in the same matrix that would be produced when the sample is recovered from the sampling system as required by the test method. An accredited audit sample provider (AASP) is an organization that has been accredited to prepare audit samples by an independent, third party accrediting body.

(A) The source owner, operator, or representative of the tested facility shall obtain an audit sample, if commercially available, from an AASP for each test method used for regulatory compliance purposes. No audit samples are required for the following test methods: Methods 3C of Appendix A-3 of Part 60, Methods 6C, 7E, 9, and 10 of Appendix A-4 of Part 60, Method 18 of Appendix A-6 of Part 60, Methods 20, 22, and 25A of Appendix A-7 of Part 60, and Methods 303, 318, 320, and 321 of Appendix A of Part 63. If multiple sources at a single facility are tested during a compliance test event, only one audit sample is required for each method used during a compliance test. The compliance authority responsible for the compliance test may waive the requirement to include an audit sample if they believe that an audit sample is not necessary. “Commercially available” means that two or more independent AASPs have blind audit samples available for purchase. If the source owner, operator, or representative cannot find an audit sample for a specific method, the owner, operator, or representative shall consult the EPA Web site at the following URL, *http://www.epa.gov/ttn/emc,* to confirm whether there is a source that can supply an audit sample for that method. If the EPA Web site does not list an available audit sample at least 60 days prior to the beginning of the compliance test, the source owner, operator, or representative shall not be required to include an audit sample as part of the quality assurance program for the compliance test. When ordering an audit sample, the source owner, operator, or representative shall give the sample provider an estimate for the concentration of each pollutant that is emitted by the source or the estimated concentration of each pollutant based on the permitted level and the name, address, and phone number of the compliance authority. The source owner, operator, or representative shall report the results for the audit sample along with a summary of the emission test results for the audited pollutant to the compliance authority and shall report the results of the audit sample to the AASP. The source owner, operator, or representative shall make both reports at the same time and in the same manner or shall report to the compliance authority first and report to the AASP. If the method being audited is a method that allows the samples to be analyzed in the field and the tester plans to analyze the samples in the field, the tester may analyze the audit samples prior to collecting the emission samples provided a representative of the compliance authority is present at the testing site. The tester may request and the compliance authority may grant a waiver to the requirement that a representative of the compliance authority must be present at the testing site during the field analysis of an audit sample. The source owner, operator, or representative may report the results of the audit sample to the compliance authority and then report the results of the audit sample to the AASP prior to collecting any emission samples. The test protocol and final test report shall document whether an audit sample was ordered and utilized and the pass/fail results as applicable.

(B) An AASP shall have and shall prepare, analyze, and report the true value of audit samples in accordance with a written technical criteria document that describes how audit samples will be prepared and distributed in a manner that will ensure the integrity of the audit sample program. An acceptable technical criteria document shall contain standard operating procedures for all of the following operations:

(1) Preparing the sample;

(2) Confirming the true concentration of the sample;

(3) Defining the acceptance limits for the results from a well qualified tester. This procedure must use well established statistical methods to analyze historical results from well qualified testers. The acceptance limits shall be set so that there is 95 percent confidence that 90 percent of well qualified labs will produce future results that are within the acceptance limit range;

(4) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(*5*) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(*6*) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(*7*) Reporting the results from each audit sample in a timely manner to the compliance authority and to the source owner, operator, or representative by the AASP. The AASP shall make both reports at the same time and in the same manner or shall report to the compliance authority first and then report to the source owner, operator, or representative. The results shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, and whether the testing company passed or failed the audit. The AASP shall report the true value of the audit sample to the compliance authority. The AASP may report the true value to the source owner, operator, or representative if the AASP's operating plan ensures that no laboratory will receive the same audit sample twice.

(*8*) Evaluating the acceptance limits of samples at least once every two years to determine in consultation with the voluntary consensus standard body if they should be changed.

(*9*) Maintaining a database, accessible to the compliance authorities, of results from the audit that shall include the name of the facility tested, the date on which the compliance test was conducted, the name of the company performing the sample collection, the name of the company that analyzed the compliance samples including the audit sample, the measured result for the audit sample, the true value of the audit sample, the acceptance range for the measured value, and whether the testing company passed or failed the audit.

(C) The accrediting body shall have a written technical criteria document that describes how it will ensure that the AASP is operating in accordance with the AASP technical criteria document that describes how audit samples are to be prepared and distributed. This document shall contain standard operating procedures for all of the following operations:

(*1*) Checking audit samples to confirm their true value as reported by the AASP.

(*2*) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years.

(*3*) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(D) The technical criteria documents for the accredited sample providers and the accrediting body shall be developed through a public process guided by a voluntary consensus standards body (VCSB). The VCSB shall operate in accordance with the procedures and requirements in the Office of Management and Budget *Circular A-119* . A copy of Circular A-119 is available upon request by writing the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503, by calling (202) 395-6880 or downloading online at *http://standards.gov/standards_gov/a119.cfm* . The VCSB shall approve all accrediting bodies. The Administrator will review all technical criteria documents. If the technical criteria documents do not meet the minimum technical requirements in paragraphs (c)(2)(iii)(B) through (C) of this section, the technical criteria documents are not acceptable and the proposed audit sample program is not capable of producing audit samples of sufficient quality to be used in a compliance test. All acceptable technical criteria documents shall be posted on the EPA Web site at the following URL, *http://www.epa.gov/ttn/emc* .

(iv) The owner or operator of an affected source shall submit the site-specific test plan to the Administrator upon the Administrator's request at least 60 calendar days before the performance test is scheduled to take place, that is, simultaneously with the notification of intention to conduct a performance test required under paragraph (b) of this section, or on a mutually agreed upon date.

(v) The Administrator may request additional relevant information after the submittal of a site-specific test plan.

The pre-test protocol for MACT compliance testing must meet the requirements of this section. This is more detailed than the typical pre-test protocol for a permit compliance test. Details of this section are not explicitly included in the permit. The permit refers the readers to CFR for details.

This applies to the hog fuel boiler and not the natural gas-fired boiler that is not subject to any emissions limits.

40 CFR 63.8(e) *Performance evaluation of continuous monitoring systems* —(1) *General.* When required by a relevant standard, and at any other time the Administrator may require under section 114 of the Act, the owner or operator of an affected source being monitored shall conduct a performance evaluation of the CMS. Such performance evaluation shall be conducted according to the applicable specifications and procedures described in this section or in the relevant standard.

CMS at IFG are COMS, oxygen analyzer, and steam rate monitor for compliance with operating limits of the hog fuel boiler.

(2) *Notification of performance evaluation.* The owner or operator shall notify the Administrator in writing of the date of the performance evaluation simultaneously with the notification of the performance test date required under § 63.7(b) or at least 60 days prior to the date the performance evaluation is scheduled to begin if no performance test is required.

IFG will comply with the notification requirements for the hog fuel boiler's CMS. This does not apply to the natural gas-fired boiler.

40 CFR 63.8(f)(4 and 6) *Use of an alternative monitoring method*. IFG does not intend to use any alternative monitoring methods.

40 CFR 63.9(b) *Initial notifications.* (1)(i) The requirements of this paragraph apply to the owner or operator of an affected source when such source becomes subject to a relevant standard… (2) The owner or operator of an affected source that has an initial startup before the effective date of a relevant standard under this part shall notify the Administrator in writing that the source is subject to the relevant standard. The notification, which shall be submitted not later than 120 calendar days after the effective date of the relevant standard (or within 120 calendar days after the source becomes subject to the relevant standard) that is May 31, 2013, and shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (i.e., physical location) of the affected source;

(iii) An identification of the relevant standard, or other requirement, that is the basis of the notification and the source's compliance date;

(iv) A brief description of the nature, size, design, and method of operation of the source and an identification of the types of emission points within the affected source subject to the relevant standard and types of hazardous air pollutants emitted; and

(v) A statement of whether the affected source is a major source or an area source.

40 CFR 63.2 *Effective date* means:

(1) With regard to an emission standard established under this part, the date of promulgation in

the FEDERAL REGISTER of such standard;

The effective date of the rule is January 31, 2013. IFG must submit the initial notification 120 days after January 31, 2013, which will be May 31, 2013.

This applies to both boilers (e.g., the natural gas-fired boiler is subject to working practice standards)

40 CFR 63.9(c) *Request for extension of compliance.* If the owner or operator of an affected source cannot comply with a relevant standard by the applicable compliance date for that source, or if the owner or operator has installed BACT or technology to meet LAER consistent with § 63.6(i)(5) of this subpart, he/she may submit to the Administrator (or the State with an approved permit program) a request for an extension of compliance as specified in § 63.6(i)(4) through § 63.6(i)(6).

40 CFR 63.6(i)(4) through § 63.6(i)(6) would allow the state to grant up to 1 additional year to comply with the standard, if such additional period is necessary for the installation of controls. IFG could request an extension if it becomes necessary.

40 CFR 63.9(d) *Notification that source is subject to special compliance requirements.* An owner or operator of a new source that is subject to special compliance requirements as specified in § 63.6(b)(3) and § 63.6(b)(4) shall notify the Administrator of his/her compliance obligations not later than the notification dates established in paragraph (b) of this section for new sources that are not subject to the special provisions.

40 CFR 63.6(b)(3) The owner or operator of an affected source for which construction or reconstruction is commenced after the proposal date of a relevant standard established under this part pursuant to section 112(d), 112(f), or 112(h) of the Act but before the effective date (that is, promulgation) of such standard shall comply with the relevant emission standard not later than the date 3 years after the effective date if…

40 CFR 63.6(b)(4) The owner or operator of an affected source for which construction or reconstruction is commenced after the proposal date of a relevant standard established pursuant to section 112(d) of the Act but before the proposal date of a relevant standard established pursuant to section 112(f) shall not be required to comply with the section 112(f) emission standard until the date 10 years after the date construction or reconstruction is commenced, except that, if the section 112(f) standard is promulgated more than 10 years after construction or reconstruction is commenced, the owner or operator must comply with the standard as provided in paragraphs (b)(1) and (2) of this section.

This does not apply to the hog fuel boiler because it is an existing source.

Does not apply to the natural gas-fired boiler because it is not subject to special compliance requirements.

40 CFR 63.9(e) *Notification of performance test.* The owner or operator of an affected source shall notify the Administrator in writing of his or her intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin to allow the Administrator to review and approve the site-specific test plan required under § 63.7(c), if requested by the Administrator, and to have an observer present during the test.

40 CFR 63.9(e) duplicates 40 CFR 63.7(b) and is not included in the permit.

IFG will notify the Administrator (DEQ and EPA) 60 days in advance of a planned MACT compliance test. Only 30-day notice is required for Idaho air permit compliance tests.

This applies to hog fuel boiler and not the natural gas-fired boiler because it is not subject to any emissions limits.

40 CFR 63.9(f) *Notification of opacity and visible emission observations.* The owner or operator of an affected source shall notify the Administrator in writing of the anticipated date for conducting the opacity or visible emission observations specified in § 63.6(h)(5), if such observations are required for the source by a relevant standard. The notification shall be submitted with the notification of the performance test date, as specified in paragraph (e) of this section, or if no performance test is required or visibility or other conditions prevent the opacity or visible emission observations from being conducted concurrently with the initial performance test required under § 63.7, the owner or operator shall deliver or postmark the notification not less than 30 days before the opacity or visible emission observations are scheduled to take place.

This does not apply. COMS is required to comply with the opacity limit for the hog fuel boiler. This does not apply to the natural gas-fired boiler because it is not subject to opacity limit under this subpart.

40 CFR 63.9(g) *Additional notification requirements for sources with continuous monitoring systems.* The owner or operator of an affected source required to use a CMS by a relevant standard shall furnish the Administrator written notification as follows:

(1) A notification of the date the CMS performance evaluation under § 63.8(e) is scheduled to begin, submitted simultaneously with the notification of the performance test date required under § 63.7(b). If no performance test is required, or if the requirement to conduct a performance test has been waived for an affected source under § 63.7(h), the owner or operator shall notify the Administrator in writing of the date of the performance evaluation at least 60 calendar days before the evaluation is scheduled to begin;

(2) A notification that COMS data results will be used to determine compliance with the applicable opacity emission standard during a performance test required by § 63.7 in lieu of Method 9 or other opacity emissions test method data, as allowed by § 63.6(h)(7)(ii), if compliance with an opacity emission standard is required for the source by a relevant standard. The notification shall be submitted at least 60 calendar days before the performance test is scheduled to begin; and

(3) A notification that the criterion necessary to continue use of an alternative to relative accuracy testing, as provided by § 63.8(f)(6), has been exceeded. The notification shall be delivered or postmarked not later than 10 days after the occurrence of such exceedance, and it shall include a description of the nature and cause of the increased emissions.

This notification requirement for sources with continuous monitoring systems applies to the hog fuel boiler and not the natural gas-fired boiler because it is not subject to any emissions limits.

Besides COMS, CMS also includes oxygen analyzer and steam rate monitor for compliance with operating limits of the hog fuel boiler.

40 CFR 63.9(h) *Notification of compliance status.* (1) The requirements of paragraphs (h)(2) through (h)(4) of this section apply when an affected source becomes subject to a relevant standard.

(2)(i) Before a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this part..

IFG has a Title V permit. This does not apply.

40 CFR 63.9(h)(3) After a title V permit has been issued to the owner or operator of an affected source [Applies because IFG Chilco has a Title V (Tier I) permit], the owner or operator of such

source shall comply with all requirements for compliance status reports contained in the source's title V permit, including reports required under this part. After a title V permit has been issued to the owner or operator of an affected source, and each time a notification of compliance status is required under this part, the owner or operator of such source shall submit the notification of compliance status to the appropriate permitting authority following completion of the relevant compliance demonstration activity specified in the relevant standard.

This applies to both boilers. IFG must submit compliance status reports to DEQ.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

This duplicates requirement under 40 CFR 63.9(b)(2) that is already included in the permit. This applies to both boilers.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. IFG will comply if they add a new unit in the future.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

This duplicates requirement under 40 CFR 63.9(e) that is already included in the permit. This applies to the hog fuel boiler and not the natural gas-fired boiler because it is not subject to any emissions limits.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

The pre-test protocol for MACT compliance testing must meet the requirements of this section. This is more detailed than the typical pre-test protocol for a permit compliance test. IFG must review the pre-test protocol carefully before it is submitted by the testing firm.

This applies to both boilers.

While the hog fuel boiler is subject to emissions limits, work practice standard, and operating limits, the natural gas-fired boiler is only subject to work practice standard (i.e., boiler tune-up).

Requirements in 40 CFR 63.9(h)(2)(ii) are not included in the permit; they are basically covered under 40 CFR 63.7545(e).

Requirements in 40 CFR 63.10(d)(2) are included in the permit and only apply to the hog fuel boiler.

40 CFR 63.9(h)(2)(ii) The notification must be sent before the close of business on the 60th day following the completion of the relevant compliance demonstration activity specified in the relevant standard (unless a different reporting period is specified in the standard, in which case the letter must be sent before the close of business on the day

the report of the relevant testing or monitoring results is required to be delivered or postmarked). For example, the notification shall be sent before close of business on the 60th (or other required) day following completion of the initial performance test and again before the close of business on the 60th (or other required) day following the completion of any subsequent required performance test. If no performance test is required but opacity or visible emission observations are required to demonstrate compliance with an opacity or visible emission standard under this part, the notification of compliance status shall be sent before close of business on the 30th day following the completion of opacity or visible emission observations. Notifications may be combined as long as the due date requirement for each notification is met.

40 CFR 63.10(d)(2) Reporting results of performance tests. Before a title V permit has been issued to the owner or operator of an affected source, the owner or operator shall report the results of any performance test under § 63.7 to the Administrator. After a title V permit has been issued to the owner or operator of an affected source, the owner or operator shall report the results of a required performance test to the appropriate permitting authority. The owner or operator of an affected source shall report the results of the performance test to the Administrator (or the State with an approved permit program) before the close of business on the 60th day following the completion of the performance test, unless specified otherwise in a relevant standard or as approved otherwise in writing by the Administrator. The results of the performance test shall be submitted as part of the notification of compliance status required under § 63.9(h).

40 CFR 63.9(h)(2)(ii) and 40 CFR 63.10(d)(2) are not included in the permit. Their contents are in 40 CFR 63.7545.

40 CFR 63.10(d)(2) applies to hog fuel boiler and does not apply to the natural gas-fired boiler.

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

This applies to both boilers.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

This applies to the hog fuel boiler.

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

This applies to the hog fuel boiler. IFG has chosen to comply with the PM emission limit through performance test.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

This applies to the hog fuel boiler.

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

This applies to the hog fuel boiler.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

This applies to the hog fuel boiler.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

This applies to the hog fuel boiler as it is subject to energy assessment. IFG may use efficiency credits (from energy assessment) through energy conservation. However, emissions averaging does not apply to IFG as explained in the previous sections.

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

(6) A signed certification that you have met all applicable emission limits and work practice standards.

This applies to both boilers. The hog fuel boiler is subject to emissions limits and work practice standards. The natural gas-fired boiler is subject to work practice (i.e., tune up.)

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

This applies to both boilers. The hog fuel boiler is subject to emissions limits and work practice standards. The natural gas-fired boiler is subject to work practice (i.e., tune up.)

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

This applies to both boilers.

(i) “This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).”

This applies to both boilers.

(ii) “This facility has had an energy assessment performed according to § 63.7530(e).”

This only applies to the hog fuel boiler.

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: “No secondary materials that are solid waste were combusted in any affected unit.”

This only applies to the hog fuel boiler.

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575… Does not apply.

(g) If you intend to commence or recommence combustion of solid waste… Does not apply.

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, … Does not apply. IFG does not anticipate switching fuels in any boilers.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7183, Jan. 31, 2013]

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

This applies to both boilers. Refer to Table 9 for more discussions.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section.

For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

For the hog fuel boiler, IFG will submit semi-annual compliance reports.

For the natural gas boiler, instead of semi-annual compliance reports, IFG can submit annual, or 5-years compliance reports, as applicable, to match the schedule of the tune-ups. Annually if it is subject to an annual tune up requirement, or 5 years if it is subject to a 5 years tune up requirement after the boiler is equipped with a continuous oxygen trim system.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

The compliance date for the hog fuel boiler is January 31, 2016 in accordance with 40 CFR 63.7495(b). Therefore, the period for first compliance report begins on January 31, 2016 and ends on July 31, 2016.

The compliance date for the natural gas-fired boiler is January 31, 2013 in accordance with 40 CFR 63.7495(a). Therefore, the period for first compliance report begins on January 31, 2013 and ends on July 31, 2013.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year

compliance report must be postmarked or submitted no later than January 31.

The first compliance report for the hog fuel boiler is due January 31, 2017. The first annual compliance report is also due January 31, 2017.

The first compliance report for the natural gas-fired boiler is due January 31, 2014. The first annual compliance report is also due January 31, 2014.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

This applies to the hog fuel boiler.

Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

This applies to the natural gas-fired boiler.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

Subsequent reports for the hog fuel boiler will cover each calendar half and will be due at the July 31 and January 31.

Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

Subsequent reports for the natural gas-fired boiler will cover each calendar half and will be due January 31.

At the time of the permit issuance, the natural gas-fired boiler is subject to an annual tune-up because it does not have a continuous oxygen trim system.

If a continuous oxygen trim system is installed, the natural boiler will be subject to a 5-year tune-up requirement, and IFG can submit a 5-year compliance report, to match the schedule of the tune-ups.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

This applies to both boilers. Both boilers are subject to annual tune-up unless a continuous oxygen trim system is installed. At the time of the permit issuance, neither of the boilers has a continuous oxygen trim system.

If a continuous oxygen trim system is installed, the boiler will be subject to the 5-year tune-up requirement.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

This applies to the hog fuel boiler not the natural gas-fired boiler because the natural gas-fired boiler is only subject to a tune-up requirement.

This applies when IFG chooses to comply with HCl and mercury limits through fuel analysis. IFG can choose performance test to demonstrate compliance with HCl and mercury limits.

(xv) Does not apply. IFG does not demonstrate compliance by emission averaging.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

This applies to the hog fuel boiler not the natural gas-fired boiler. IFG complies with CO and PM limits through performance test.

(ix) and (xv) do not apply. IFG does not plan to burn a new type of fuel and does not demonstrate compliance by emission averaging.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

This applies to the hog fuel boiler not the natural gas-fired boiler.

The CMS are COMS for compliance with opacity limit, O_2 analyzer system for compliance with CO limit, and steaming rate monitor for keeping below 110% of operating loading that is established through performance testing.

(xv) does not apply. IFG does not demonstrate compliance by emission averaging.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(v) only applies to the hog fuel boiler.

The CMS are COMS for compliance with opacity limit, O_2 analyzer system for compliance with CO limit, and steaming rate monitor for keeping below 110% of operating loading that is established through performance testing. IFG does not use CEMS.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

These apply to both boilers. IFG does not plan to burn new types of fuel.

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

Does not apply. IFG does not plan to burn a new type of fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

This only applies to the hog fuel boiler.

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

This only applies to the hog fuel boiler.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

This only applies to the hog fuel boiler. The hog fuel boiler has COMS and CPMS (e.g.O_2 analyzer and steam rate monitor) and does not have CEMS.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

This only applies to the hog fuel boiler.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

This applies to both boilers. Each boiler is subject to an annual tune-up unless a continuous oxygen trim system is installed. At the time of the permit issuance, neither of the boilers has a continuous oxygen trim system.

If a continuous oxygen trim system is installed, the boiler will be subject to a 5-year tune-up requirement.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

Does not apply. IFG does not demonstrate compliance by emission averaging.

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

This does not apply. IFG does not use CMS that are listed under (xvi).

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

This applies to IFG.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

This applies to the hog fuel boiler for CO, PM, and HCl and mercury emissions limits through either performance test or fuel analysis.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

These apply to the hog fuel boiler for opacity limit using COMS, average oxygen content using O_2 analyzer, and 110% operating loading using steam rate monitor.

(f)-(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

This applies to both boilers.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to

U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

This applies to the hog fuel boiler.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

IFG does not use CEMS; this does not apply.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

This applies to both boilers.

[78 FR 7183, Jan. 31, 2013]

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

This applies to bother boilers.

Semiannual compliance report applies to the hog fuel boiler.

IFG can submit compliance reports for the natural gas-fired boiler consistent with its tune-up requirement that is annual, or 5-years if the natural gas-fired boiler installs a continuous oxygen trim system.

IFG must keep copies of all the notifications and reports they submit. Recommend storing records off-site as well.

40 CFR 63.10(b)(2)(xiv)

(xiv) All documentation supporting initial notifications and notifications of compliance status under § 63.9.

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

> 40 CFR 63.10(b)(xiii) All emission levels relative to the criterion for obtaining permission to use an alternative to the relative accuracy test, if the source has been granted such permission under § 63.8(f)(6);

This applies to the hog fuel boiler.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

This applies to the hog fuel boiler because it uses COMS and CMS (i.e., O_2 analyzer and steam rate monitor.) This does not apply to the natural gas-fired boiler.

IFG must keep copies of the COMS charts and/or electronic records, as well as all performance test information and reports. Recommend storing records off-site as well. Find more discussions for paragraphs (b)(1) through (5) of this section in the following:

(1) Records described in § 63.10(b)(2)(vii) through (xi).

40 CFR 63.10(b)(2)(vii) through (xi)

(vii) All required measurements needed to demonstrate compliance with a relevant standard (including, but not limited to, 15-minute averages of CMS data, raw performance testing measurements, and raw performance evaluation measurements, that support data that the source is required to report);

(A) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) …

Does not apply. IFG does not use CEMS.

(B) This paragraph applies to owners or operators required to install a CEMS …

Does not apply. IFG does not use CEMS.

(C) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (b)(2)(vii), if the administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(viii) All results of performance tests, CMS performance evaluations, and opacity and visible emission observations;

(ix) All measurements as may be necessary to determine the conditions of performance tests and performance evaluations;

(x) All CMS calibration checks;

(xi) All adjustments and maintenance performed on CMS;

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as

required in § 63.6(h)(7)(i) and (ii).

40 CFR 63.6(h)(7)(i) and (ii).

(7) *Use of a continuous opacity monitoring system.* (i) The owner or operator of an affected source required to use a continuous opacity monitoring system (COMS) shall record the monitoring data produced during a performance test required under § 63.7 and shall furnish the Administrator a written report of the monitoring results in accordance with the provisions of § 63.10(e)(4).

(ii) Whenever an opacity emission test method has not been specified in an applicable subpart, or an owner or operator of an affected source is required to conduct Test Method 9 observations (see appendix A of part 60 of this chapter), the owner or operator may submit, for compliance purposes, COMS data results produced during any performance test required under § 63.7 in lieu of Method 9 data. If the owner or operator elects to submit COMS data for compliance with the opacity emission standard, he or she shall notify the Administrator of that decision, in writing, simultaneously with the notification under § 63.7(b) of the date the performance test is scheduled to begin. Once the owner or operator of an affected source has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent performance tests required under § 63.7, unless the owner or operator notifies the Administrator in writing to the contrary not later than with the notification under § 63.7(b) of the date the subsequent performance test is scheduled to begin.

(3) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

Does not apply. IFG does not use CEMS.

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

This applies the hog fuel boiler. IFG will keep COMS records, oxygen records, and steam rate monitoring and fuel analysis records as required. Refer to Table 8 for additional information.

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

This applies the hog fuel boiler because it is subject to emissions limits in Table 2 to this subpart. IFG will keep all the applicable records for the hog fuel boiler.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter...

Does not apply. IFG only uses hog fuel in the boiler.

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

Does not apply. IFG does not apply for limited use for the boiler.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

This applies because IFG is likely to choose compliance with HCl limit through fuel analysis.

"Equation 12" should be "equation 16". It appears a mistake.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

This applies because IFG is likely to choose compliance with mercury limit through fuel analysis.

"Equation 13" should be "equation 17". It appears a mistake.)

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM

emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

This does not apply. IFG chooses to comply with the PM limit not the TSM limit.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(e) If you elect to average emissions consistent with § 63.7522…Does not apply.

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

This applies to the hog fuel boiler if IFG uses efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533.

This does not apply to the natural gas-fired boiler because it is not subject to the energy measures requirement.

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

Does not apply.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

Does not apply.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

For the hog fule boiler, it is already listed under 40 CFR 63.7555(d)(10). Apparently, this applies to the natural gas-fired boiler. IFG will keep the required startup and shut down records.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

For the hog fule boiler, it is already listed under 40 CFR 63.7555(d)(11). Apparently, this applies to the natural gas-fired boiler. IFG will keep the required startup and shut down records.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7185, Jan. 31, 2013]

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

40 CFR 63.10(b)(1).

40 CFR 63.10 (b) *General recordkeeping requirements.* (1) The owner or operator of an affected source subject to the provisions of this part shall maintain files of all information (including all reports and notifications) required by this part recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

These apply to both boilers.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

This applies to both boilers.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

[76 FR 15664, Mar. 21, 2011 as amended at 78 FR 7186, Jan. 31, 2013]

§ 63.7575 What definitions apply to this subpart?

The definitions used in the permit and the statement of basis are highlighted.

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.,* baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751-11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.,* almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of “coal” includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation. (1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751-11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be "capable of combusting" fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent

measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure $C_3 H_8$.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396-10 (incorporated by reference, *see* § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7 \text{ MMBtu/Mwh} \quad \text{(Eq. 21)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2 \text{ MMBtu/Mwh} \quad \text{(Eq. 22)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9 \text{ MMBtu/Mwh} \quad \text{(Eq. 23)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8 \text{ MMBtu/Mwh} \quad \text{(Eq. 24)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other) subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_T \times 10.4 \text{ MMBtu/Mwh} \quad \text{(Eq. 25)}$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.,* materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428-B2959, (800) 262-1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016-5990, (800) 843-2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH-1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800-463-6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B-1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214-230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.,* California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.,* Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

[78 FR 15664, Mar. 21, 2011, as amended at 78 FR 7163, Jan. 31, 2013]

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

Though the natural gas-fired boiler is a new source, the boiler is not subject to any limits in Table 1. Therefore, this table does not apply.

[78 FR 7193, Jan. 31, 2013]

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing Boilers and Process Heaters

The hog fuel boiler is an existing boiler and is subject to the limits (highlighted) in this table.

As stated in § 63.7500, you must comply with the following applicable emission limits:

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam	For M26A, Collect a minimum of 1 dscm

designed to burn solid fuel The hog fuel boiler is subject to the limits.			output or 0.27 lb per MWh	per run; for M26, collect a minimum of 120 liters per run.
	b. Mercury	5.7E-06 lb per MMBtu of heat input	6.4E-06 lb per MMBtu of steam output or 7.3E-05 lb per MWh	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b]collect a minimum of 3 dscm.
2 to 6…Does not apply.				
7. Stokers/sloped grate/others designed to burn wet biomass fuel The hog fuel boiler is subject to the limits	a. CO (or CEMS) IFG chooses to use source test rather than CEMS.	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average)	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average	1 hr minimum sampling time.
	b. Filterable PM (or TSM) IFG chooses to compliance with filterable PM limit.	3.7E-02 lb per MMBtu of heat input; or (2.4E-04 lb per MMBtu of heat input)	4.3E-02 lb per MMBtu of steam output or 5.2E-01 lb per MWh; or (2.8E-04 lb per MMBtu of steam output or 3.4E-04 lb per MWh)	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel Does not apply according to the application.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen	4.2E-01 lb per MMBtu of steam output or 5.1 lb per MWh	1 hr minimum sampling time.

	b. Filterable PM (or TSM)	3.2E-01 lb per MMBtu of heat input; or (4.0E-03 lb per MMBtu of heat input)	3.7E-01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E-03 lb per MMBtu of steam output or 5.6E-02 lb per MWh)	Collect a minimum of 1 dscm per run.
9 to 18 Does not apply.				

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[78 FR 7195, Jan. 31, 2013]

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

Some requirements in this table apply to the hog fuel boiler and natural gas-fired boiler.

As stated in § 63.7500, you must comply with the following applicable work practice standards:

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater This can apply to hog fuel boiler or natural gas boiler when the boiler installs a continuous oxygen trim system that maintains an optimum air to fuel ratio in the future. At the time of the permit issuance, neither the hog fuel boiler nor natural gas-fired has a continuous oxygen trim system. However, IFG	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.

requested to keep the requirement in the permit for the possibility of installing the system in the future.	
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater This requirement applies to both the natural gas-fired boiler and the hog fuel-fired boiler at the time of permit issuance. The boiler(s) will be subject to item 1 of this table when the boiler(s) installs a continuous oxygen trim system that maintains an optimum air to fuel ratio.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units This requirement applies to the hog fuel boiler. The hog fuel boiler is not a limited use boiler.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575:
	a. A visual inspection of the boiler or process heater system.
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints.

	c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator.
	d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage.
	e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified.
	f. A list of cost-effective energy conservation measures that are within the facility's control.
	g. A list of the energy savings potential of the energy conservation measures identified.
	h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup The hog fuel boiler is an existing boiler and subject to limits in Table 2. Therefore, it is subject to the requirement. The natural gas-fired boiler is a new boiler but not subject to limits in Table 1 or 2 or 11 through 13; therefore, it is not subject to this requirement.	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas.
	If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose.

	You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown The hog fuel boiler is an existing boiler and subject to limits in Table 2; therefore, it is subject to the requirement. The natural gas-fired boiler is a new boiler but not subject to limits in Table 1 or 2 or 11 through 13; therefore, it is not subject to this requirement.	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR.
	You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

[78 FR 7198, Jan. 31, 2013]

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

This table contains requirements applicable to the hog fuel boiler.

As stated in § 63.7500, you must comply with the applicable operating limits:

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1 to 4. Does not apply because IFG does not use the listed control methods.	
6. Any other add-on air pollution control	This option is for boilers and process heaters that operate

type on units not using a PM CPMS Applies to the hog fuel boiler, which is controlled by a multiclone followed by an electrified filter bed (EFB).	dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis Applies to the hog fuel boiler. IFG may use fuel analysis to demonstrate compliance with HCl and mercury emission limits. The only fuel to be used is hog fuel, so the only differences in HCl and mercury would be naturally occurring variations.	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing Applies to the hog fuel boiler	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system IFG will comply with this requirement.	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in 40 CFR 63.7525(a). At the time of the permit issuance, the hog fuel boiler does not have a continuous oxygen trim system.
10. SO_2CEMS	Does not apply because IFG does not use CEMS.

[78 FR 7199, Jan. 31, 2013]

Table 5 to Subpart DDDDD of Part 63—Performance Testing Requirements

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

Apply to the hog fuel boiler because it is subject the emissions limits.

To conduct a performance test for the following pollutant...	You must...	Using...
1. Filterable PM	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 to part 60 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A-3 or A-6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
2. TSM	Does not apply. FG has chosen to comply the PM limit not the TSM limit.	
3. Hydrogen chloride If IFG complies with the limit through performance test.	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-2 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]

	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the hydrogen chloride emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A-8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
4. Mercury If IFG complies with the limit through performance test.	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas	Method 2, 2F, or 2G at 40 CFR part 60, appendix A-1 or A-2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A-8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates	Method 19 F-factor methodology at 40 CFR part 60, appendix A-7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A-3 of this chapter, or ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A-3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A-4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7200, Jan. 31, 2013]

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

Apply to the hog fuel boiler because it is subject the emissions limits.

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323 [a](for solid), or EPA 821-R-01-013 (for liquid or solid), or ASTM D4177 [a](for liquid), or ASTM D4057 [a](for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M [a](for coal), ASTM D5198 [a](for biomass), or EPA 3050 [a](for solid fuel), or EPA 821-R-01-013 [a](for liquid or solid), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), or ASTM D5864 [a]for liquids and other solids, or ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a], ASTM E871 [a], or ASTM D5864 [a], or ASTM D240, or ASTM D95 [a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a](for coal), EPA SW-846-7471B [a](for solid samples), or EPA SW-846-7470A [a](for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	Equation 8 in § 63.7530.
	h. Calculate the mercury	Equations 10 and 12 in § 63.7530.

	emission rate from the boiler or process heater in units of pounds per million Btu	
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192 [a], or ASTM D7430 [a], or ASTM D6883 [a], or ASTM D2234/D2234M [a](for coal) or ASTM D6323 [a](for coal or biomass), ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW-846-3050B [a](for solid samples), EPA SW-846-3020A [a](for liquid samples), ASTM D2013/D2013M§[a](for coal), or ASTM D5198§[a](for biomass), or EPA 3050 [a]or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a](for coal) or ASTM E711 [a](for biomass), ASTM D5864, ASTM D240 [a]or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a]or ASTM E871 [a], or D5864 [a], or ASTM D240 [a], or ASTM D95[a](for liquid fuels), or ASTM D4006 [a](for liquid fuels), or ASTM D4177 [a](for liquid fuels) or ASTM D4057 [a](for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample	EPA SW-846-9250 [a], ASTM D6721 [a], ASTM D4208 [a](for coal), or EPA SW-846-5050 [a]or ASTM E776 [a](for solid fuel), or EPA SW-846-9056 [a]or SW-846-9076 [a](for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels		Does not apply; IFG does not use other gas 1 fuels.
4. TSM for solid fuels		Does not apply; IFG has chosen to comply the PM limit not the TSM limit.

[a] Incorporated by reference, see § 63.14.

[78 FR 7201, Jan. 31, 2013]

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits

Apply to the hog fuel boiler because it is subject operating limits.

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1 to 3.	Does not apply because IFG does not use the listed control methods.			
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520	(1) Data from the oxygen analyzer system specified in § 63.7525(a)	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests.
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test	a. Boiler or process heater operating load	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c)	(1) Data from the operating load monitors or from steam generation monitors	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test.
				(b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test.
				(c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110

				percent) as your operating limit.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7203, Jan. 31, 2013]

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

Apply to the hog fuel boiler because it is subject operating limits.

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and
	b. Reducing the opacity monitoring data to 6-minute averages; and
	c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2 to 7	Does not apply because IFG does not use the listed control methods and PM CPMS.
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and
	b. Reduce the data to 12-month rolling averages; and
	c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2).
	b. Reducing the data to 30-day rolling averages; and
	c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes.

	b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2 emissions using SO_2 CEMS	Does not apply because IFG does not use SO_2 CEMS.

[78 FR 7204, Jan. 31, 2013]

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

This applies to both boilers.

As stated in § 63.7550, you must comply with the following requirements for reports:

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report CMS related requirements only apply to the hog fuel boiler and not to the natural gas-fired boiler.	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b). For hog fuel boiler, semiannually. For natural gas-fired boiler, annually if it is subject to an annual tune up requirement, or 5 years if it is subject to a 5 years tune up requirement after the boiler is equipped with a continuous oxygen trim system.
	b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs	IFG does not use continuous emissions monitoring system (CEMS). The natural gas-fired boiler does not use CMS and is not subject to emissions and operating limits. It is subject to work practice standards. The hog fuel boiler uses CMS and is subject to emissions and operating limits.

	were out-of-control during the reporting period; and	40 CFR 63.8(7)(i) A CMS is out of control if— (A) The zero (low-level), mid-level (if applicable), or high-level calibration drift (CD) exceeds two times the applicable CD specification in the applicable performance specification or in the relevant standard; or (B) The CMS fails a performance test audit (e.g., cylinder gas audit), relative accuracy audit, relative accuracy test audit, or linearity test audit; or (C) The COMS CD exceeds two times the limit in the applicable performance specification in the relevant standard.
	c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and	This applies to the hog fuel boiler. The natural gas-fired boiler does not use CMS and is not subject to emissions and operating limits.
	d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e)	This applies to the hog fuel boiler. The natural gas-fired boiler does not use CMS and is not subject to emissions and operating limits.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

Applies to both boilers.

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)-(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards.	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.

§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
§ 63.7(e)(2)-(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.

§ 63.8(g)	Reduction of monitoring data	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.

§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.
§ 63.1(a)(5),(a)(7)-(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)-(4), (c)(9).	Reserved	No.

[76 FR 15664, Mar. 21, 2011, as amended at 78 FR 7205, Jan. 31, 2013]

Table 11 to Subpart DDDDD of Part 63—Toxic Equivalency Factors for Dioxins/Furans

Does not apply to the boilers.

Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011

Does not apply to the boilers.

Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before January 31, 2013

Does not apply to the boilers.

[78 FR 7210, Jan. 31, 2013]