Statement of Basis

Permit to Construct No. P-2008.0204
Project ID 62150

Idaho Forest Group LLC - Bennett - Grangeville
Grangeville, Idaho

Facility ID 049-00003

Final

April 10, 2020
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Permit Writer

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

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ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
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 units
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAS No.	Chemical Abstracts Service registry number
CBP	concrete batch plant
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	CO_2 equivalent emissions
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
FEC	Facility Emissions Cap
GACT	Generally Available Control Technology
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
HMA	hot mix asphalt
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
iwg	inches of water gauge
km	kilometers
lb/hr	pounds per hour
lb/qtr	pound per quarter
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
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards

O&M	operation and maintenance
O_2	oxygen
PAH	polyaromatic hydrocarbons
PC	permit condition
PCB	polychlorinated biphenyl
PERF	Portable Equipment Relocation Form
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
POM	polycyclic organic matter
ppm	parts per million
ppmw	parts per million by weight
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PTC	permit to construct
PTC/T2	permit to construct and Tier II operating permit
PTE	potential to emit
PW	process weight rate
RAP	recycled asphalt pavement
RFO	reprocessed fuel oil
RICE	reciprocating internal combustion engines
Rules	*Rules for the Control of Air Pollution in Idaho*
scf	standard cubic feet
SCL	significant contribution limits
SIP	State Implementation Plan
SM	synthetic minor
SM80	synthetic minor facility with emissions greater than or equal to 80% of a major source threshold
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/day	tons per calendar day
T/hr	tons per hour
T/yr	tons per consecutive 12 calendar month period
T2	Tier II operating permit
TAP	toxic air pollutants
TEQ	toxicity equivalent
T-RACT	Toxic Air Pollutant Reasonably Available Control Technology
ULSD	ultra-low sulfur diesel
U.S.C.	United States Code
VOC	volatile organic compounds
yd^3	cubic yards
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

Idaho Forest Group (IFG) is located northwest of Grangeville, Idaho on US Highway 95. The site is approximately 75 air-miles west of the Montana boarder and 25 air-miles northeast of the Oregon border. IFG – Grangeville mill lies in Idaho County, in the Southeast ¼ of Section 13, Township 30 North, Range 2 East. UTM Coordinates for the site are Zone 11, Easting 556.3 kilometers, and Northing 5087.7 kilometers. The elevation of the site is approximately 3,250 feet above sea level.

The facility includes a sawmill, lumber dry kilns and a Planer mill. A wood-fired boiler provides steam to heat the dry kilns. Emissions from the facility include criteria air pollutants, hazardous air pollutants (HAPs), and toxic air pollutants (TAPs).

The primary processes at the facility are the sawmill, steam plant, dry kilns, and the Planer mill. Logs are debarked then cut to dimension in the saw mill. Green lumber from the saw mill is dried in the dry kilns, planed in the planer mill, and then packaged to be shipped by truck or rail. Bark from the debarker is shredded and transferred to the boiler for use as fuel.

The boilers and kilns can operate 24 hours per day, 7 days per week, and 52 weeks per year. The sawmill, planning and material handling facilities generally operate only 6 days per week throughout the year. IFG employs a single operational scenario.

Log Processing: Log processing equipment includes an end flare reducer, debarker, log merchandizer saw, bark hog, and hogged bark transferred to the fuel silo. Particulate matter (PM) emissions from the end flare reducer and the debarker are controlled by enclosures surrounding the equipment. The merchandizer saw and the hog are fully enclosed with their associated PM emissions being minimal. A conveyor transports the hogged bark to the boiler area. Total emissions from conveying and transferring the bark to the boiler are included in the estimated emissions from the conveyor and transfer emissions groups.

Sawmill: Sawmill operations located in the sawmill building produce wood scraps and sawdust. A chipper cuts the wood scraps into marketable chips and screens out the fine material. Fine material that falls through the chipper screen is added to the sawdust. A pneumatic conveyor transfers the dried sawdust from the building to the sawdust transfer cyclone located on the outdoor sawdust truck bin. A mechanical conveyor transfers the green chips to the chip truck bin. Fugitive sawmill emissions are minimized by the building enclosure. Fugitive PM emissions occur when the sawdust and chip bins are opened from the bottom to release material into trucks. Fugitive emissions from sawmill residuals handling are included in the conveyor, transfer and storage emissions groups.

Lumber Drying: Five dry kilns which are heated via indirect steam heat supplied by the hog fuel boiler. Initial moisture content of the lumber is in the range of 40-60%. The final moisture content varies depending on species and product but is generally around 15%. Moisture from the lumber is released from the dry kilns through multiple roof vents. The vents are opened and closed as needed to control the temperature and moisture within the kiln. Batch drying cycles in the dry kilns can last for 13 to 80 hours. Volatile Organic Compounds (VOC) contained in the green lumber is volatilized during kiln drying. Most of the hydrocarbons contained in coniferous trees are terpenes, primarily α-pinene, and limonene.

Planer Mill: The planers and associated equipment are located in the planer building. The air quality within the planer building is controlled with negative air, effectively eliminating fugitive emissions from the planer facility. Dried planer shavings are transported pneumatically from the planer building to cyclones at the shavings bin. Air emitted from the cyclones is further cleaned in the planer shavings baghouses.

The planer facility also includes a chipper, located inside the building. Dried planer chips are transferred pneumatically to a cyclone on the planer chip bin. Fugitive emissions from planer residuals handling are included in the conveyor, transfer and storage emissions groups.

<u>Steam Plant:</u> A Wellons fuel cell boiler provides steam to heat the five dry kilns. The boiler emits fine particulate matter (PM_{10} and $PM_{2.5}$), nitrogen oxides (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), VOC, and HAPs. Generation of NO_X and CO emissions are controlled through boiler design and operation. Outside of the boiler design and operation there are no emissions controls for these pollutants. SO_2 and VOC emissions are minimal from hog fuel boilers, based on the composition of the wood fuel. $PM_{10}/PM_{2.5}$ emissions from the boiler are controlled with a multiclone and an electrostatic precipitator (ESP).

Permitting History

Refer to the current Tier I Operating Permit Statement of Basis for the permitting history.

Application Scope

This PTC is a revision at an existing Tier I facility to update and include DEQ approved emission factors for new and existing wood species, reclassification from HAP minor to HAP major, discontinue HAP tracking, add VOC emissions from pneumatic conveyance, add a baghouse to control emissions from the planer shavings truck bin cyclone, and implement facility-wide VOC tracking for PSD purposes.

Application Chronology

December 11, 2018	DEQ received an application and an application fee.
January 3, 2019	DEQ determined that the application was incomplete.
January 7, 2019	DEQ received supplemental information from the applicant.
March 18, 2019	DEQ received supplemental information from the applicant.
March 18, 2019	DEQ determined that the application was complete.
April 18, 2019	DEQ made available the draft permit and statement of basis for peer and regional office review.
May 3, 2019	DEQ made available the draft permit and statement of basis for applicant review.
May 6, 2019	DEQ received a $1,000 permit processing fee and will send in the remaining $4,000 permit processing fee at a later date.
July 2, 2019	DEQ made available a second draft permit and statement of basis for applicant review.
November 14, 2019	DEQ made available a third draft permit and statement of basis for applicant review.
December 6, 2019	DEQ made available a fourth draft permit and statement of basis for applicant review.
December 18 – January 17, 2020	DEQ provided a public comment period on the proposed action.
February 18 – April 3, 2020	DEQ provided a concurrent EPA and affected state review on the proposed action.
April 10, 2020	DEQ issued the final permit and statement of basis.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION

Source ID No.	Sources	Control Equipment
B-1	Hog Fuel Boiler: Manufacturer: Wellons Model: 2D2C8.0A Manufacture Date: June 2005 Serial Number: B-2421-501 Production: 80,000 pounds per hour Fuel Rate: 13.6 BDT/hr Fuel Heat Content: 17.5 MMBtu/BDT Fuel: Wood	Multiclone Manufacturer: Wellons Model No.: W-144 Air flow rate: 64,500 CFM at sea level & 350 °F. Electrostatic Precipitator Manufacturer: Wellons Model No.: Size No. 9 Number of fields: 2 Plate Cleaning System: Plate
NA	Three Moore Dry Kilns Manufacturer: Moore Manufacture Date: 1972 Model Length: 88 feet Maximum Capacity: 2.0 MMBDF/Day	None
NA	Two Wellons Dry Kilns Manufacturer: Wellons Manufacture Date: 2005 Model Length: 88 feet Maximum Capacity: 2.0 MMBDF/Day	
BH-1	Sawmill sawdust cyclone with baghouse	Baghouse Manufacturer: Clarke Sheet Metal Model No.: CSM 60-20
BH-2	Planer shavings cyclone with baghouse	Baghouse Manufacturer: Clarke Sheet Metal Model No.: 100-20G1
BH-3	Planer shavings bin vent cyclone with baghouse	Baghouse Manufacturer: Clarke Sheet Metal Model No.: DWG 849-0101
CY-1	Sawmill truck bin cyclone	None
CY-2	Planer chipping room cyclone	
CY-3	Planer chip bin cyclone	
CY-4	Saw filing room cyclone	
CY-5	Retail shavings transfer/packaging cyclone	
NA	Fire Water Pump	Emergency-Use Reciprocating Internal Combustion Engine (RICE)
NA[(a)]	Waste Oil Heater	None

a) The waste oil heater qualifies as an exempt source under Category II Exemption 58.01.01.222(h)

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit an emission inventory was developed for the one wood-fired boiler, five kilns, sawmill sawdust cyclone, Planer shavings cyclone, Planer shavings bin vent cyclone, sawmill truck bin cyclone, Planer chipping room cyclone, saw filing room cyclone, retail shavings transfer/packaging cyclone, pneumatic conveyors, fire water pump, and waste oil heater operations at the facility (see Appendix A) associated with this proposed project. Emissions estimates of criteria pollutant, HAP PTE were based on emission factors from AP-42 1.1.6, 13.2.1, 13.2.2, 13.2.4, EPA Region 10 2014 memo Federal Air Rules for Reservations (FARR) (2018AAG2189, page 103), NCASI study (2018AAG2189, page 107), Wellons manufacturer predicted CO emission factor, existing $PM_{2.5}/PM_{10}$ permit limit, EPA Region 10 temperature dependent emission factor equations specific to wood species, National Council for Air and Stream Improvement (NCASI) September 1996 Technical Bulletin No. 723 (TB723), IDEQ control efficiency standards for $PM_{2.5}/PM_{10}$ 50% for cyclones and 67% for baghouses (2018AAG2189, page 101), operation of 8,760 hours per year, and process information specific to the facility for this proposed project. The waste oil heater meets the exemption criteria under Category II Exemption 58.01.01.222(h).

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

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

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

Source	PM_{10}		SO_2		NO_X		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Hog fuel boiler	6.6	28.90	27.20	119.00	29.00	127.00	23.20	101.00	5.80	25.00
All kilns	5.65	24.00	--	--	--	--	--	--	44.60	188.00
BH-1 Sawmill sawdust cyclone (prev. CY-11)	0.02	0.04	--	--	--	--	--	--	--	--
BH-2 Planer shavings cyclone (prev. CY-72)	0.22	0.45	--	--	--	--	--	--	--	--
BH-3 Planer shavings bin vent cyclone (prev. CY-73)	1.40	2.80	--	--	--	--	--	--	--	--
CY-1 Sawmill sawdust cyclone (prev. CY-12)	0.52	1.00	--	--	--	--	--	--	--	--
CY-4 Filing room cyclone (prev. CY-41)	0.0012	0.0024	--	--	--	--	--	--	--	--
CY-3 Planer chip cyclone (prev. CY-71)	0.49	0.99	--	--	--	--	--	--	--	--
Pre-Project Totals	**14.90**	**58.18**	**27.20**	**119.00**	**29.00**	**127.00**	**23.20**	**101.00**	**50.40**	**213.00**

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

Post Project Potential to Emit

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

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

Table 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{2.5}$		PM_{10}		SO_2		NO_X		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
B-1 Hog fuel boiler	6.6	28.90	6.6	28.90	2.90	12.68	56.84	248.96	23.20	101.60	5.80	25.40
All kilns[(e)]	5.65	24.00	5.65	24.00	--	--	--	--	--	--	44.60	188.00
BH-1 Sawmill sawdust cyclone	0.02	0.04	0.02	0.04	--	--	--	--	--	--	--	--
BH-2 Planer shavings cyclone	0.22	0.45	0.22	0.45	--	--	--	--	--	--	--	--
BH-3 Planer shavings bin vent cyclone	1.40	2.80	1.40	2.80	--	--	--	--	--	--	--	--
CY-1 Sawmill sawdust cyclone	0.52	1.00	0.52	1.00	--	--	--	--	--	--	--	--
CY-2 Planer chipping room cyclone	0.19	0.30	0.38	0.58	--	--	--	--	--	--	--	--
CY-3 Planer chip cyclone	0.19	0.30	0.49	0.99	--	--	--	--	--	--	--	--
CY-4 Filing room cyclone	6.4E-05	2.00E-04	0.0012	0.0024	--	--	--	--	--	--	--	--
Cy-5 Retail shavings transfer cyclone	0.08	0.25	0.16	0.50	--	--	--	--	--	--	--	--
Pneumatic[(c)] Conveyance	--	--	--	--	--	--	--	--	--	--	2.60	11.4
Fire water pump	4.54E-03	2.27E-04	4.58E-03	2.29E-04	8.92E-04	4.46E-05	1.06	5.32E-02	3.31E-02	1.65E-03	8.82E-03	4.41E-04
Waste oil heater	0.06	0.03	0.08	0.04	0.00	0.05	0.06	0.03	0.01	0.004	0.10	0.002
Post Project Totals	**14.93**	**58.07**	**15.53**	**59.30**	**2.90**	**12.73**	**57.96**	**249.04**	**23.24**	**101.61**	**53.11**	**249.00**[(d)]

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
b) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.
c) The pneumatic conveyance $PM_{2.5/10}$ emissions are listed above under the following units: BH-1, CY-1, BH-2, CY-2, and CY-3.
d) The column totals 224.41T/yr, however the facility wants a cap of 249 T/yr with the ability to flex emissions between the hog fuel boiler, kilns, pneumatic conveyance, fire water pump, and the waste oil heater.
e) Using the worst case scenario, emission factor, and maximum annual throughput for the kilns, the kiln VOC emissions are 371 T/yr, however due to the facility-wide VOC emission limit, the total potential to emit is presented as 249 T/yr.

Change in Potential to Emit

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

Table 4 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{2.5}$		PM_{10}		SO_2		NO_X		CO		VOC	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Pre-Project Potential to Emit	0.00	0.00	14.90	58.18	27.20	119.00	29.00	127.00	23.20	101.00	50.40	213.00
Post Project Potential to Emit	0.06	0.03	15.52	59.30	2.90	12.73	29.11	249.04	23.21	101.61	53.10	249.00
Changes in Potential to Emit	**0.06 [a]**	**0.03 [a]**	**0.62**	**1.12**	**-24.30**	**-106.27**	**0.11**	**122.04**	**0.01**	**0.61**	**2.70**	**36.00**

a) The only change in $PM_{2.5}$ is the same as PM_{10}, which is due to the waste oil heater, fire pump, CY2, and CY5. $PM_{2.5}$ was never modeled or listed separately in the original permitting action and is a subset of PM_{10},

TAP Emissions

IDAPA 58.01.01.210 requires an analysis of toxic air pollutant (TAP) emissions from the proposed project. TAP emissions have been estimated as described in the emissions inventory report in Appendix C of the application (2019AAG442). This PTC modification project does not result in an increase of TAP emissions. Therefore, no analyses are required for TAP compliance.

Post Project HAP Emissions

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

Table 5 HAZARDOUS AIR POLLUTANTS EMISSIONS POTENTIAL TO EMIT SUMMARY

Hazardous Air Pollutants	PTE (T/yr)
Acetaldehyde	4.97E+00
Acetophenone	1.63E-06
Acrolein	2.03E+00
Benzene	2.13E+00
bis(2-ethylhexyl)phthalate (DEHP)	2.39E-05
Bromomethane (Methyl Bromide)	7.62E-03
Carbon Tetrachloride	2.29E-02
Chlorine	4.01E-01
Chlorobenzene	1.68E-02
Chloroform	1.42E-02
Chloromethane (Methyl Chloride)	1.17E-02
1, 2-Dichloroethane (Ethylene Dichloride)	1.47E-02
Dichloromethane (Methylene Chloride)	1.47E-01
1, 2-Dichloropropane (Propylene Dichloride)	1.68E-02
2, 4 Dinitrophenol	9.15E-05
2,3,7,8-Tetrachlorodibenzo-p-dioxins	4.36E-09
Tetrachlorodibenzo-p-dioxins	2.38E-07
2,3,7,8-Tetrachlorodibenzo-p-furans	4.56E-08
Tetrachlorodibenzo-p-furans	3.80E-07
Ethylbenzene	1.57E-02
Formaldehyde	2.93E+00
Hydrogen Chloride (Hydrochloric Acid)	1.12E+01
Naphthalene	4.92E-02
4-Nitrophenol	5.58E-05
Pentachlorophenol	2.59E-05
Phenol	2.59E-02

Hazardous Air Pollutants	PTE (T/yr)
Propionaldehyde	2.06E-01
Polycyclic Organic Matter (POM) 7-PAH Group	1.49E-03
Benzo(a)pyrene	1.32E-03
Styrene	9.64E-01
2,3,7,8-Tetrachlorodibenzo-p-dioxins	4.37E-09
Toluene	4.67E-01
1,1,1-Trichloroethane (Methyl Chloroform)	1.58E-02
Trichloroethane (Trichloroethylene)	1.52E-02
Trichlorofluoromethane	2.08E-02
2,4,6-Trichlorophenol	1.12E-05
Vinyl Chloride	9.15E-03
o-Xylene	1.27E-02
Antimony	4.01E-03
Arsenic	1.12E-02
Beryilium	5.59E-04
Cadmium	2.08E-03
Chromium, total	1.07E-02
Chromium, hexavalent	1.78E-03
Cobalt	3.30E-03
Lead	2.44E-02
Manganese	8.13E-01
Mercury	2.90E-03
Nickel	1.68E-02
Phosphorus	1.37E-02
Selenium	1.42E-03
Methanol	23.95
Totals	**50.57**

a) Methanol is the single highest HAP, Methanol is emitted from the kilns only. Both the kilns and boiler emit formaldehyde, acetaldehyde, Propionaldehyde and Acrolein. All other pollutants are emitted by the boiler only.

Ambient Air Quality Impact Analyses

A PTC revision for inclusion of DEQ approved temperature dependent emission factor equations for five new wood species and four existing wood species, new emission factors for the wood-fired boiler, incorporating the existing green-wood residue from pneumatic conveyance, and VOC emissions from the existing fire water pump and waste oil heater did not require a technical analysis; however, a technical analysis for the original PTC can be found in the Statement of Basis for PTC No. P-050214, issued July 10, 2006.

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

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

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For HAPs (Hazardous Air Pollutants) Only:

A = Use when any one HAP has permitted emissions > 10 T/yr or if the aggregate of all HAPS (Total HAPs) has permitted emissions > 25 T/yr.

SM80 = Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits > 8 T/yr of a single HAP or ≥ 20 T/yr of Total HAPs.

SM = Use if a synthetic minor (uncontrolled HAPs emissions are > 10 T/yr or if the aggregate of all uncontrolled HAPs (Total HAPs) emissions are > 25 T/yr and permitted emissions fall below applicable major source thresholds) and the permit sets limits < 8 T/yr of a single HAP and/or < 20 T/yr of Total HAPs.

B = Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 10 and 25 T/yr HAP major source thresholds.

UNK = Class is unknown.

For All Other Pollutants:

A = Use when permitted emissions of a pollutant are > 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (uncontrolled emissions are > 100 T/yr and permitted emissions fall below 100 T/yr) and permitted emissions of the pollutant are < 80 T/yr.

B = Use when the potential to emit (i.e. uncontrolled emissions and permitted emissions) are below the 100 T/yr major source threshold.

UNK = Class is unknown.

Table 6 REGULATED AIR POLLUTANT FACILITY CLASSIFICATION

Pollutant	Uncontrolled PTE (T/yr)	Permitted PTE (T/yr)	Major Source Thresholds (T/yr)	AIRS/AFS Classification
PM	>100	<100	**100**	SM
PM_{10}	>100	<100	**100**	SM
$PM_{2.5}$	>100	<100	**100**	SM
SO_2	>100	<100	**100**	SM
NO_X	>100	>100	**100**	A
CO	>100	>100	**100**	A
VOC	>100	>100	**100**	A
HAP (single)	>10	>10	**10**	A
Total HAPs	>25	>25	**25**	A

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201... Permit to Construct Required

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

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401... Tier II Operating Permit

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

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625... Visible Emissions

The sources of PM emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by Permit Conditions 2.4 and 3.3.

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676... Standards for New Sources

The fuel burning equipment located at this facility, with a maximum rated input of ten (10) million BTU per hour or more, are subject to a particulate matter limitation of 0.080 gr/dscf of effluent gas corrected to 8% oxygen by volume when combusting gaseous fuels. Fuel-Burning Equipment is defined as any furnace, boiler, apparatus, stack and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer. This requirement is assured by Permit Conditions 2.3 and 2.6.

Particulate Matter – New Equipment Process Weight Limitations (IDAPA 58.01.01.701)

IDAPA 58.01.01.701... Particulate Matter – New Equipment Process Weight Limitations

This permitting action does not increase the throughput for the facility processes. Therefore the previous analysis can be located under Section 5.4 record number (2011AAG2998).

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

IDAPA 58.01.01.301... Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility have a potential to emit greater than 100 tons per year for NO_X, CO, and VOC or 10 tons per year for any single HAP or 25 tons per year for all HAP combined as demonstrated previously in the Emissions Inventories Section of this analysis. Therefore, this facility is classified as a Criteria Pollutant and HAP Major Source subject to Tier I requirements, as defined in IDAPA 58.01.01.008.10.

PSD Classification (40 CFR 52.21)

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

The facility is classified as an existing major stationary source, because the estimated emissions of PM_{10}, SO_2, NO_X, CO, VOC, and HAP have the potential to exceed major stationary source thresholds. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a).

This facility is not one of the facilities designated and does not have facility-wide emissions for any criteria pollutant that exceed 250 T/yr. In addition, the facility is not 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), the PSD requirements do not apply.

NSPS Applicability (40 CFR 60)

Because the facility has a Wellons hog fuel boiler the following is an NSPS applicability analysis for the proposed equipment:

- 40 CFR 60, Subpart A - Standards of Performance for New Stationary Sources – General Provisions. DEQ is delegated this Subpart.
- 40 CFR 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. DEQ is delegated this Subpart.

40 CFR 60, Subpart A .... Standards of Performance for New Stationary Sources – General Provisions

§60.1 .... Applicability

Section (a) Except as provided in Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source e which contains an affected facility of this part apply to the owner or operator of any stationary source e which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

The facility has a Wellons hog fuel boiler and is subject to the requirements of 40 CFR 60 Subpart Db – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, and 40 CFR 60 Subpart A – General Provisions.

Section (b) Any new or revised standard of performance promulgated pursuant to section 111(b) of the Act shall apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

Section (c) In addition to complying with the provisions of this part, the owner or operator of an affected facility may be required to obtain an operating permit issued to stationary sources by an authorized State air pollution control agency or by the Administrator of the U.S. Environmental Protection Agency (EPA) pursuant to Title V of the Clean Air Act (Act) as emended November 15, 1990 (42 U.S.C. 7661). For more information about obtaining an operating permit see part 70 of this chapter.

IFG holds an Idaho Tier I Operating Permit, which meets this requirement.

§60.4 .... Address

Section (a) All requests, reports, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate to the appropriate Regional Office of the U.S. Environmental Protection Agency to the attention of the Director of the Division indicated in the following list of EPA Regional Offices.

Region 10 (Alaska, Oregon, Idaho, Washington), Director, Air and Waste Management Division, U.S. Environmental Protection Agency, 1200 Sixth Avenue, Seattle WA 98101.

(14) State of Idaho, Department of Health and Welfare, Statehouse, Boise, ID 83701.

§60.7 .... Notification and Record Keeping

Section (a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under §60.15 of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form.

IFG complied with this notification on schedule.

(3) A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date.

IFG complied with this notification on schedule.

(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in §60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5) A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with §60.13(c). Notification shall be postmarked not less than 30 days prior to such date.

(6) A notification of the anticipated date for conducting the opacity observations required by §60.11(e)(1) of this part. The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date.

(7) A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by §60.8 in lieu of Method 9 observation data as allowed by §60.11(e)(5) of this part. This notification shall be postmarked not less than 30 days prior to the date of the performance test.

(b) Any owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.

IFG maintains the required records for the boiler. The required information is included in Idaho Form C9 and C10 submittals as appropriate.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by- case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information.

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factors(s) used, date and time of commencement, completion of each time period of excess emissions, and the process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

(d) The summary report form shall contain the information and be in the format shown in figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total; CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) shall both be submitted.

(e)(1) Notwithstanding the frequency of reporting requirements specified in paragraph (c) of this section, an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility’s excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and the applicable standard; and

(iii)The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in paragraph (e)(2) of this section.

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in paragraphs (e)(1) and (e)(2) of this section.

(f) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring systems performance evaluations; all continuous monitoring system or monitoring device calibrations checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows:

IFG maintains the required records

(1) This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS sub hourly measurements as required under paragraph (f) of this section, the owner or operator shall retain the most recent consecutive three averaging periods of sub hourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard.

(2) This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS sub hourly measurements as required under paragraph (f) of this section, the owner or operator shall retain all sub hourly measurements for the most recent reporting period. The sub hourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator.

(3) The Administrator or delegated authority, upon notification to the source, may require the owner or operator to maintain all measurements as required by paragraph (f) of this section, if the Administrator or the delegated authority determines these records are required to more accurately assess the compliance status of the affected source.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

§60.8 .... Performance Tests

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section, within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(1) If a force majeure is about to occur, occurs, or has occurred for which the affected owner or operator intends to assert a claim of force majeure, the owner or operator shall notify the Administrator, in writing as soon as practicable following the date the owner or operator first knew, or through due diligence should have known that the event may cause or caused a delay in testing beyond the regulatory deadline, but the notification must occur before the performance test deadline unless the initial force majeure or a subsequent force majeure event delays the notice, and in such cases, the notification shall occur as soon as practicable.

(2) The owner or operator shall provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in testing beyond the regulatory deadline to the force majeure; describe the measures taken or to be taken to minimize the delay; and identify a date by which the owner or operator proposes to conduct the performance test. The performance test shall be conducted as soon as practicable after the force majeure occurs.

(3) The decision as to whether or not to grant an extension to the performance test deadline is solely within the discretion of the Administrator. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an extension as soon as practicable.

(4) Until an extension of the performance test deadline has been approved by the Administrator under paragraphs (a)(1), (2), and (3) of this section, the owner or operator of the affected facility remains strictly subject to the requirements of this part.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard, or (5) approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days' notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the owner or operator of an affected facility shall notify the Administrator (or delegated State or local agency) as soon as possible of any delay in the original test date, either by providing at least 7 days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Administrator (or delegated State or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s)

(3) Safe access to sampling platform(s)

(4) Utilities for sampling and testing equipment

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method.

(1) Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

(2) Contents of report (electronic or paper submitted copy). Unless otherwise specified in a relevant standard or test method, or as otherwise approved by the Administrator in writing, the report for a performance test shall include the elements identified in paragraphs (f)(2)(i) through (vi) of this section.

(i) General identification information for the facility including a mailing address, the physical address, the owner or operator or responsible official (where applicable) and his/her email address, and the appropriate Federal Registry (FRS) number for the facility.

(ii) Purpose of the test including the applicable regulation(s) requiring the test, the pollutant(s) and other parameters being measured, the applicable emission standard and any process parameter component, and a brief process description.

(iii) Description of the emission unit tested including fuel burned, control devices, and vent characteristics; the appropriate source classification code (SCC); the permitted maximum process rate (where applicable); and the sampling location.

(iv) Description of sampling and analysis procedures used and any modifications to standard procedures, quality assurance procedures and results, record of process operating conditions that demonstrate the applicable test conditions are met, and values for any operating parameters for which limits were being set during the test.

(v) Where a test method requires you record or report, the following shall be included: Record of preparation of standards, record of calibrations, raw data sheets for field sampling, raw data sheets for field and laboratory analyses, chain-of-custody documentation, and example calculations for reported results.

(vi) Identification of the company conducting the performance test including the primary office address, telephone number, and the contact for this test program including his/her email address.

(g) 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.

(1) 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 3A and 3C of appendix A-3 of part 60, Methods 6C, 7E, 9, and 10 of appendix A-4 of part 60, Methods 18 and 19 of appendix A-6 of part 60, Methods 20, 22, and 25A of appendix A-7 of part 60, Methods 30A and 30B of appendix A-8 of part 60, and Methods 303, 318, 320, and 321 of appendix A of part 63 of this chapter. 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, 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 then 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 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.

(2) 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:

(i) Preparing the sample;

(ii) Confirming the true concentration of the sample;

(iii) 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 qualifies lads will produce future results that are within the acceptance limit range.

(iv) Providing the opportunity for the compliance authority to comment on the selected concentration level for an audit sample;

(v) Distributing the sample to the user in a manner that guarantees that the true value of the sample is unknown to the user;

(vi) Recording the measured concentration reported by the user and determining if the measured value is within acceptable limits;

(vii) The AASP shall report the results from each audit sample in a timely manner to the compliance authority and then to the source owner, operator, or representative. 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.

(viii) Evaluating the acceptance limits of samples at least once every two years to determine in cooperation with the voluntary consensus standard body if they should be changed;

(ix) 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.

(3) 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:

(i) Checking audit samples to confirm their true value as reported by the AASP;

(ii) Performing technical systems audits of the AASP's facilities and operating procedures at least once every two years;

(iii) Providing standards for use by the voluntary consensus standard body to approve the accrediting body that will accredit the audit sample providers.

(4) 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 (g)(2) through (4)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.

(h) Unless otherwise specified in the applicable subpart, each test location must be verified to be free of cyclonic flow and evaluated for the existence of emission gas stratification and the required number of sampling traverse points. If other procedures are not specified in the applicable subpart to the regulations, use the appropriate procedures in Method 1 to check for cyclonic flow and Method 7E to evaluate emission gas stratification and selection of sampling points.

(i) Whenever the use of multiple calibration gases is required by a test method, performance specification, or quality assurance procedure in a part 60 standard or appendix, Method 205 of 40 CFR 51, appendix M of this chapter, "Verification of Gas Dilution Systems for Field Instrument Calibrations, "may be used.

§60.9 .... Availability of Information

The availability to the public of information provided to, or otherwise obtained by, the Administrator under this part shall be governed by part 2 of this chapter. (Information submitted voluntarily to the Administrator for the purposes of §§60.5 and 60.6 is governed by §§2.201 through 2.213 of this chapter and not by §2.301 of this chapter).

§60.10 .... State Authority

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§60.11 .... Compliance with Standards and maintenance Requirements

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by §60.8, unless otherwise specified in the applicable standard.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in paragraph (e)(5) of this section. For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).

(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating 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, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)(1) For the purpose of demonstrating initial compliance, opacity observations shall be conducted concurrently with the initial performance test required in §60.8 unless one of the following conditions apply. If no performance test under §60.8 is required, then opacity observations shall be conducted within 60 days after achieving the maximum production rate at which the affected facility will be operated but no later than 180 days after initial startup of the facility. If visibility or other conditions prevent the opacity observations from being conducted concurrently with the initial performance test required under §60.8, the source owner or operator shall reschedule the opacity observations as soon after the initial performance test as possible, but not later than 30 days thereafter, and shall advise the Administrator of the rescheduled date. In these cases, the 30-day prior notification to the Administrator required in §60.7(a)(6) shall be waived. The rescheduled opacity observations shall be conducted (to the extent possible) under the same operating conditions that existed during the initial performance test conducted under §60.8. The visible emissions observer shall determine whether visibility or other conditions prevent the opacity observations from being made concurrently with the initial performance test in accordance with procedures contained in Method 9 of appendix B of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The owner or operator of an affected facility shall make available, upon request by the Administrator, such records as may be necessary to determine the conditions under which the visual observations were made and shall provide evidence indicating proof of current visible observer emission certification. Except as provided in paragraph (e)(5) of this section, the results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification 1 in appendix B of this part, has been properly maintained and (at the time of the alleged violation) that the resulting data have not been altered in any way.

(2) Except as provided in paragraph (e)(3) of this section, the owner or operator of an affected facility to which an opacity standard in this part applies shall conduct opacity observations in accordance with paragraph (b) of this section, shall record the opacity of emissions, and shall report to the Administrator the opacity results along with the results of the initial performance test required under §60.8. The inability of an owner or operator to secure a visible emissions observer shall not be considered a reason for not conducting the opacity observations concurrent with the initial performance test.

(3) The owner or operator of an affected facility to which an opacity standard in this part applies may request the Administrator to determine and to record the opacity of emissions from the affected facility during the initial performance test and at such times as may be required. The owner or operator of the affected facility shall report the opacity results. Any request to the Administrator to determine and to record the opacity of emissions from an affected facility shall be included in the notification required in §60.7(a)(6). If, for some reason, the Administrator cannot determine and record the opacity of emissions from the affected facility during the performance test, then the provisions of paragraph (e)(1) of this section shall apply.

(4) An owner or operator of an affected facility using a continuous opacity monitor (transmissometer) shall record the monitoring data produced during the initial performance test required by §60.8 and shall furnish the Administrator a written report of the monitoring results along with Method 9 and §60.8 performance test results.

(5) An owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under §60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under §60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under §60.8 until the owner or operator notifies the Administrator, in

writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under §60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under §60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in §60.13(c) of this part, that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine compliance with the opacity standard.

(6) Upon receipt from an owner or operator of the written reports of the results of the performance tests required by §60.8, the opacity observation results and observer certification required by §60.11(e)(1), and the COMS results, if applicable, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If COMS data results are used to comply with an opacity standard, only those results are required to be submitted along with the performance test results required by §60.8. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with §60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(7) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(8) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

§60.12.. Circumvention

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

§60.13.. Monitoring Requirements

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under §60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under §60.11(e)(5), he shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of this part before the performance test required under §60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under §60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part, The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under §60.8 and as described in §60.11(e)(5) shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in paragraph (c) of this section at least 10 days before the performance test required under §60.8 is conducted.

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d)(1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. Owners and operators of a COMS installed in accordance with the provisions of this part must check the zero and upscale (span) calibration drifts at least once daily. For a particular COMS, the acceptable range of zero and upscale calibration materials is defined in the applicable version of PS-1 in appendix B of this part. For a COMS, the optical surfaces, exposed to the effluent gases, must be cleaned before performing the zero and upscale drift adjustments, except for systems using automatic zero adjustments. The optical surfaces must be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.

(2) Unless otherwise approved by the Administrator, the following procedures must be followed for a COMS. Minimum procedures must include an automated method for producing a simulated zero opacity condition and an upscale opacity condition using a certified neutral density filter or other related technique to produce a known obstruction of the light beam. Such procedures must provide a system check of all active analyzer internal optics with power or curvature, all active electronic circuitry including the light source and photodetector assembly, and electronic or electro-mechanical systems and hardware and or software used during normal measurement operation.

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) All continuous monitoring systems referenced by paragraph (c) of this section for measuring opacity of emissions shall 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.

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part shall be used.

(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.

(h)(1) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in §60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period.

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, i.e., one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:

(A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or

(B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under §60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.

(i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following:

(1) Alternative monitoring requirements when installation of a continuous monitoring system or monitoring device specified by this part would not provide accurate measurements due to liquid water or other interferences caused by substances in the effluent gases.

(2) Alternative monitoring requirements when the affected facility is infrequently operated.

(3) Alternative monitoring requirements to accommodate continuous monitoring systems that require additional measurements to correct for stack moisture conditions.

(4) Alternative locations for installing continuous monitoring systems or monitoring devices when the owner or operator can demonstrate that installation at alternate locations will enable accurate and representative measurements.

(5) Alternative methods of converting pollutant concentration measurements to units of the standards.

(6) Alternative procedures for performing daily checks of zero and span drift that do not involve use of span gases or test cells.

(7) Alternatives to the A.S.T.M. test methods or sampling procedures specified by any subpart.

(8) Alternative continuous monitoring systems that do not meet the design or performance requirements in Performance Specification 1, appendix B, but adequately demonstrate a definite and consistent relationship between its measurements and the measurements of opacity by a system complying with the requirements in Performance Specification 1. The Administrator may require that such demonstration be performed for each affected facility.

(9) Alternative monitoring requirements when the effluent from a single affected facility or the combined effluent from two or more affected facilities is released to the atmosphere through more than one point.

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B may be requested as follows:

(1) An alternative to the reference method tests for determining RA is available for sources with emission rates demonstrated to be less than 50 percent of the applicable standard. A source owner or operator may petition the Administrator to waive the RA test in Section 8.4 of Performance Specification 2 and substitute the procedures in Section 16.0 if the results of a performance test conducted according to the requirements in §60.8 of this subpart or other tests performed following the criteria in §60.8 demonstrate that the emission rate of the pollutant of interest in the units of the applicable standard is less than 50 percent of the applicable standard. For sources subject to standards expressed as control efficiency levels, a source owner or operator may petition the Administrator to waive the RA test and substitute the procedures in Section 16.0 of Performance Specification 2 if the control device exhaust emission rate is less than 50 percent of the level needed to meet the control efficiency requirement. The alternative procedures do not apply if the continuous emission monitoring system is used to determine compliance continuously with the applicable standard. The petition to waive the RA test shall include a detailed description of the procedures to be applied. Included shall be location and procedure for conducting the alternative, the concentration or response levels of the alternative RA materials, and the other equipment checks included in the alternative procedure. The Administrator will review the petition for completeness and applicability. The determination to grant a waiver will depend on the intended use of the CEMS data (e.g., data collection purposes other than NSPS) and may require specifications more stringent than in Performance Specification 2 (e.g., the applicable emission limit is more stringent than NSPS).

(2) The waiver of a CEMS RA test will be reviewed and may be rescinded at such time, following successful completion of the alternative RA procedure, that the CEMS data indicate that the source emissions are approaching the level. The criterion for reviewing the waiver is the collection of CEMS data showing that emissions have exceeded 70 percent of the applicable standard for seven, consecutive, averaging periods as specified by the applicable regulation(s). For sources subject to standards expressed as control efficiency levels, the criterion for reviewing the waiver is the collection of CEMS data showing that exhaust emissions have exceeded 70 percent of the level needed to meet the control efficiency requirement for seven, consecutive, averaging periods as specified by the applicable regulation(s) [e.g., §§60.45(g) (2) and (3), 60.73(e), and 60.84(e)]. It is the responsibility of the source operator to maintain records and determine the level of emissions

relative to the criterion on the waiver of RA testing. If this criterion is exceeded, the owner or operator must notify the Administrator within 10 days of such occurrence and include a description of the nature and cause of the increasing emissions. The Administrator will review the notification and may rescind the waiver and require the owner or operator to conduct a RA test of the CEMS as specified in Section 8.4 of Performance Specification 2.

§60.14 .... Modification

(a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kg/hr of any pollutant discharged into the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of “Compilation of Air Pollutant Emission Factors,” EPA Publication No. AP-42, or other emission factors determined by the Administrator to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.

(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in paragraph (b)(1) of this section does not demonstrate to the Administrator's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emission factors as referenced in paragraph (b)(1) of this section. When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in appendix C of this part shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Administrator shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of this part any other facility within that source.

(e) The following shall not, by themselves, be considered modifications under this part:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of paragraph (c) of this section and §60.15.

(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to that source type, as provided by §60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.

(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

(i) Repowering projects that are awarded funding from the Department of Energy as permanent clean coal technology demonstration projects (or similar projects funded by EPA) are exempt from the requirements of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(j)(1) Repowering projects that qualify for an extension under section 409(b) of the Clean Air Act are exempt from the requirements of this section, provided that such change does not increase the actual hourly emissions of any pollutant regulated under this section above the actual hourly emissions achievable at that unit during the 5 years prior to the change.

(2) This exemption shall not apply to any new unit that:

(i) Is designated as a replacement for an existing unit;

(ii) Qualifies under section 409(b) of the Clean Air Act for an extension of an emission limitation compliance date under section 405 of the Clean Air Act; and

(iii) Is located at a different site than the existing unit.

(k) The installation, operation, cessation, or removal of a temporary clean coal technology demonstration project is exempt from the requirements of this section. A temporary clean coal control technology demonstration project, for the purposes of this section is a clean coal technology demonstration project that is operated for a period of 5 years or less, and which complies with the State implementation plan for the State in which the project is located and other requirements necessary to attain and maintain the national ambient air quality standards during the project and after it is terminated.

(l) The reactivation of a very clean coal-fired electric utility steam generating unit is exempt from the requirements of this section.

§60.15 .... Reconstruction

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

§60.17 .... Incorporation by Reference

Refer to the regulation

§60.18 .... General Control Device and Work Practice Requirements

(a) Introduction. (1) This section contains requirements for control devices used to comply with applicable subparts of 40 CFR parts 60 and 61. The requirements are placed here for administrative convenience and apply only to facilities covered by subparts referring to this section.

(2) This section also contains requirements for an alternative work practice used to identify leaking equipment. This alternative work practice is placed here for administrative convenience and is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(b) Flares. Paragraphs (c) through (f) apply to flares.

(c)(1) Flares shall be designed for and operated with no visible emissions as determined by the methods specified in paragraph (f), except for periods not to exceed a total of 5 minutes during any 2 consecutive hours.

(2) Flares shall be operated with a flame present at all times, as determined by the methods specified in paragraph (f).

(3) An owner/operator has the choice of adhering to either the heat content specifications in paragraph (c)(3)(ii) of this section and the maximum tip velocity specifications in paragraph (c)(4) of this section, or adhering to the requirements in paragraph (c)(3)(i) of this section.

(i)(A) Flares shall be used that have a diameter of 3 inches or greater, are nonassisted, have a hydrogen content of 8.0 percent (by volume), or greater, and are designed for and operated with an exit velocity less than 37.2 m/sec (122 ft/sec) and less than the velocity, Vmax, as determined by the following equation:

$V_{max} = (X_{H2} - K_1) * K_2$

Where:

V_{max} = Maximum permitted velocity, m/sec.

K_1 = Constant, 6.0 volume-percent hydrogen.

K_2 = Constant, 3.9(m/sec)/volume-percent hydrogen.

X_{H2} = The volume-percent of hydrogen, on a wet basis, as calculated by using the American Society for Testing and Materials (ASTM) Method D1946-77. (Incorporated by reference as specified in §60.17).

(B) The actual exit velocity of a flare shall be determined by the method specified in paragraph (f)(4) of this section.

(ii) Flares shall be used only with the net heating value of the gas being combusted being 11.2 MJ/scm (300 Btu/scf) or greater if the flare is steam-assisted or air-assisted; or with the net heating value of the gas being combusted being 7.45 MJ/scm (200 Btu/scf) or greater if the flare is nonassisted. The net heating value of the gas being combusted shall be determined by the methods specified in paragraph (f)(3) of this section.

(4)(i) Steam-assisted and nonassisted flares shall be designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4) of this section, less than 18.3 m/sec (60 ft/sec), except as provided in paragraphs (c)(4) (ii) and (iii) of this section.

(ii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) are allowed if the net heating value of the gas being combusted is greater than 37.3 MJ/scm (1,000 Btu/scf).

(iii) Steam-assisted and nonassisted flares designed for and operated with an exit velocity, as determined by the methods specified in paragraph (f)(4), less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(5), and less than 122 m/sec (400 ft/sec) are allowed.

(5) Air-assisted flares shall be designed and operated with an exit velocity less than the velocity, V_{max}, as determined by the method specified in paragraph (f)(6).

(6) Flares used to comply with this section shall be steam-assisted, air-assisted, or nonassisted.

(d) Owners or operators of flares used to comply with the provisions of this subpart shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs. Applicable subparts will provide provisions stating how owners or operators of flares shall monitor these control devices.

(e) Flares used to comply with provisions of this subpart shall be operated at all times when emissions may be vented to them.

(f)(1) Method 22 of appendix A to this part shall be used to determine the compliance of flares with the visible emission provisions of this subpart. The observation period is 2 hours and shall be used according to Method 22.

(2) The presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame.

(3) The net heating value of the gas being combusted in a flare shall be calculated using the following equation:

where:

H_T = Net heating value of the sample, MJ/scm; where the net enthalpy per mole of offgas is based on combustion at 25 °C and 760 mm Hg, but the standard temperature for determining the volume corresponding to one mole is 20 °C;

C_i = Concentration of sample component i in ppm on a wet basis, as measured for organics by Reference Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (Incorporated by reference as specified in §60.17); and

H_i = Net heat of combustion of sample component i, kcal/g mole at 25 °C and 760 mm Hg. The heats of combustion may be determined using ASTM D2382-76 or 88 or D4809-95 (incorporated by reference as specified in §60.17) if published values are not available or cannot be calculated.

(4) The actual exit velocity of a flare shall be determined by dividing the volumetric flowrate (in units of standard temperature and pressure), as determined by Reference Methods 2, 2A, 2C, or 2D as appropriate; by the unobstructed (free) cross sectional area of the flare tip.

(5) The maximum permitted velocity, V_{max}, for flares complying with paragraph (c)(4)(iii) shall be determined by the following equation.

$$\text{Log}_{10} (V_{max}) = (H_T + 28.8)/31.7$$

V_{max} = Maximum permitted velocity, M/sec

28.8 = Constant

31.7 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(6) The maximum permitted velocity, V_{max}, for air-assisted flares shall be determined by the following equation.

$$V_{max} = 8.706 + 0.7084 (H_T)$$

V_{max} = Maximum permitted velocity, m/sec

8.706 = Constant

0.7084 = Constant

H_T = The net heating value as determined in paragraph (f)(3).

(g) Alternative work practice for monitoring equipment for leaks. Paragraphs (g), (h), and (i) of this section apply to all equipment for which the applicable subpart requires monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor, except for closed vent systems, equipment designated as leakless, and equipment identified in the applicable subpart as having no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background. An owner or operator may use an optical gas imaging instrument instead of a 40 CFR part 60, appendix A-7, Method 21 monitor. Requirements in the existing subparts that are specific to the Method 21 instrument do not apply under this section. All other requirements in the applicable subpart that are not addressed in paragraphs (g), (h), and (i) of this section apply to this standard. For example, equipment specification requirements, and non-Method 21 instrument recordkeeping and reporting requirements in the applicable subpart continue to apply. The terms defined in paragraphs (g)(1) through (5) of this section have meanings that are specific to the alternative work practice standard in paragraphs (g), (h), and (i) of this section.

(1) Applicable subpart means the subpart in 40 CFR parts 60, 61, 63, or 65 that requires monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(2) Equipment means pumps, valves, pressure relief valves, compressors, open-ended lines, flanges, connectors, and other equipment covered by the applicable subpart that require monitoring with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(3) Imaging means making visible emissions that may otherwise be invisible to the naked eye.

(4) Optical gas imaging instrument means an instrument that makes visible emissions that may otherwise be invisible to the naked eye.

(5) Repair means that equipment is adjusted, or otherwise altered, in order to eliminate a leak.

(6) Leak means:

(i) Any emissions imaged by the optical gas instrument;

(ii) Indications of liquids dripping;

(iii) Indications by a sensor that a seal or barrier fluid system has failed; or

(iv) Screening results using a 40 CFR part 60, appendix A-7, Method 21 monitor that exceed the leak definition in the applicable subpart to which the equipment is subject.

(h) The alternative work practice standard for monitoring equipment for leaks is available to all subparts in 40 CFR parts 60, 61, 63, and 65 that require monitoring of equipment with a 40 CFR part 60, appendix A-7, Method 21 monitor.

(1) An owner or operator of an affected source subject to CFR parts 60, 61, 63, or 65 can choose to comply with the alternative work practice requirements in paragraph (i) of this section instead of using the 40 CFR part 60, appendix A-7, Method 21 monitor to identify leaking equipment. The owner or operator must document the equipment, process units, and facilities for which the alternative work practice will be used to identify leaks.

(2) Any leak detected when following the leak survey procedure in paragraph (i)(3) of this section must be identified for repair as required in the applicable subpart.

(3) If the alternative work practice is used to identify leaks, re-screening after an attempted repair of leaking equipment must be conducted using either the alternative work practice or the 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart to which the equipment is subject.

(4) The schedule for repair is as required in the applicable subpart.

(5) When this alternative work practice is used for detecting leaking equipment, choose one of the monitoring frequencies listed in Table 1 to subpart A of this part in lieu of the monitoring frequency specified for regulated equipment in the applicable subpart. Reduced monitoring frequencies for good performance are not applicable when using the alternative work practice.

(6) When this alternative work practice is used for detecting leaking equipment the following are not applicable for the equipment being monitored:

(i) Skip period leak detection and repair;

(ii) Quality improvement plans; or

(iii) Complying with standards for allowable percentage of valves and pumps to leak.

(7) When the alternative work practice is used to detect leaking equipment, the regulated equipment in paragraph (h)(1)(i) of this section must also be monitored annually using a 40 CFR part 60, appendix A-7, Method 21 monitor at the leak definition required in the applicable subpart. The owner or operator may choose the specific monitoring period (for example, first quarter) to conduct the annual monitoring. Subsequent monitoring must be conducted every 12 months from the initial period. Owners or operators must keep records of the annual Method 21 screening results, as specified in paragraph (i)(4)(vii) of this section.

(i) An owner or operator of an affected source who chooses to use the alternative work practice must comply with the requirements of paragraphs (i)(1) through (i)(5) of this section.

(1) Instrument Specifications. The optical gas imaging instrument must comply with the requirements in (i)(1)(i) and (i)(1)(ii) of this section.

(i) Provide the operator with an image of the potential leak points for each piece of equipment at both the detection sensitivity level and within the distance used in the daily instrument check described in paragraph (i)(2) of this section. The detection sensitivity level depends upon the frequency at which leak monitoring is to be performed.

(ii) Provide a date and time stamp for video records of every monitoring event.

(2) Daily Instrument Check. On a daily basis, and prior to beginning any leak monitoring work, test the optical gas imaging instrument at the mass flow rate determined in paragraph (i)(2)(i) of this section in accordance with the procedure specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each camera configuration used during monitoring (for example, different lenses used), unless an alternative method to demonstrate daily instrument checks has been approved in accordance with paragraph (i)(2)(v) of this section.

(i) Calculate the mass flow rate to be used in the daily instrument check by following the procedures in paragraphs (i)(2)(i)(A) and (i)(2)(i)(B) of this section.

(A) For a specified population of equipment to be imaged by the instrument, determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level.

(B) Multiply the standard detection sensitivity level, corresponding to the selected monitoring frequency in Table 1 of subpart A of this part, by the mass fraction of detectable chemicals from the stream identified in paragraph (i)(2)(i)(A) of this section to determine the mass flow rate to be used in the daily instrument check, using the following equation.

Where:

Edic = Mass flow rate for the daily instrument check, grams per hour

xi = Mass fraction of detectable chemical(s) i seen by the optical gas imaging instrument, within the distance to be used in paragraph (i)(2)(iv)(B) of this section, at or below the standard detection sensitivity level, Esds.

Esds = Standard detection sensitivity level from Table 1 to subpart A, grams per hour

k = Total number of detectable chemicals emitted from the leaking equipment and seen by the optical gas imaging instrument.

(ii) Start the optical gas imaging instrument according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer's instructions.

(iii) Use any gas chosen by the user that can be viewed by the optical gas imaging instrument and that has a purity of no less than 98 percent.

(iv) Establish a mass flow rate by using the following procedures:

(A) Provide a source of gas where it will be in the field of view of the optical gas imaging instrument.

(B) Set up the optical gas imaging instrument at a recorded distance from the outlet or leak orifice of the flow meter that will not be exceeded in the actual performance of the leak survey. Do not exceed the operating parameters of the flow meter.

(C) Open the valve on the flow meter to set a flow rate that will create a mass emission rate equal to the mass rate specified in paragraph (i)(2)(i) of this section while observing the gas flow through the optical gas imaging instrument viewfinder. When an image of the gas emission is seen through the viewfinder at the required emission rate, make a record of the reading on the flow meter.

(v) Repeat the procedures specified in paragraphs (i)(2)(ii) through (i)(2)(iv) of this section for each configuration of the optical gas imaging instrument used during the leak survey.

(vi) To use an alternative method to demonstrate daily instrument checks, apply to the Administrator for approval of the alternative under §60.13(i).

(3) Leak Survey Procedure. Operate the optical gas imaging instrument to image every regulated piece of equipment selected for this work practice in accordance with the instrument manufacturer's operating parameters. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

(4) Recordkeeping. You must keep the records described in paragraphs (i)(4)(i) through (i)(4)(vii) of this section:

(i) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(ii) The detection sensitivity level selected from Table 1 to subpart A of this part for the optical gas imaging instrument.

(iii) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of this section.

(iv) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of this section.

(v) The daily instrument check. Record the distance, per paragraph (i)(2)(iv)(B) of this section, and the flow meter reading, per paragraph (i)(2)(iv)(C) of this section, at which the leak was imaged. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(vi) Recordkeeping requirements in the applicable subpart. A video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements of the applicable subparts if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(vii) The results of the annual Method 21 screening required in paragraph (h)(7) of this section. Records must be kept for all regulated equipment specified in paragraph (h)(1) of this section. Records must identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in the existing applicable subpart.

(5) Reporting. Submit the reports required in the applicable subpart. Submit the records of the annual Method 21 screening required in paragraph (h)(7) of this section to the Administrator via e-mail to CCG-AWP@EPA.GOV.

§60.19 .... General Notification and Reporting Requirements

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word “calendar” is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning 1 year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning 1 year after the stationary source is required to be in compliance with the applicable subpart in this part, or 1 year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f)(1)(i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part.

(ii) An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

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

§60.40b .... Applicability and Delegation of Authority

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 megawatts (MW) (100 million British thermal units per hour (MMBtu/hr)).

The Wellons boiler has a heat capacity greater than 100 MMBtu/hr and it was built after June 19, 1984. Therefore, NSPS Subpart Db applies to this boiler.

(b) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1984, but on or before June 19, 1986, is subject to the following standards:

(1) Coal-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the particulate matter (PM) and nitrogen oxides (NOX) standards under this subpart.

(2) Coal-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are subject to the PM and NOX standards under this subpart and to the sulfur dioxide (SO2) standards under subpart D (§60.43).

(3) Oil-fired affected facilities having a heat input capacity between 29 and 73 MW (100 and 250 MMBtu/hr), inclusive, are subject to the NOX standards under this subpart.

(4) Oil-fired affected facilities having a heat input capacity greater than 73 MW (250 MMBtu/hr) and meeting the applicability requirements under subpart D (Standards of performance for fossil-fuel-fired steam generators; §60.40) are also subject to the NOX standards under this subpart and the PM and SO2 standards under subpart D (§§60.42 and 60.43).

This does not apply, the Wellons boiler was constructed after June 19, 1984 and after June 19, 1986.

(c) 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.

The Wellons boiler is subject to the PM standards under this subpart. The Wellons boiler is not subject to the NO_X and SO_2 standards under subpart J or Ja of this part because the facility is not a petroleum refinery.

(d) Affected facilities that also meet the applicability requirements under subpart E (Standards of performance for incinerators; §60.50) are subject to the NO_X and PM standards under this subpart.

The subpart does not apply to this facility because the facility does not have an incinerator.

(e) Steam generating units meeting the applicability requirements under subpart Da (Standards of performance for electric utility steam generating units; §60.40Da) are not subject to this subpart.

The subpart does not apply to this facility because the facility does not have an electric utility steam generating unit.

(f) Any change to an existing steam generating unit for the sole purpose of combusting gases containing total reduced sulfur (TRS) as defined under §60.281 is not considered a modification under §60.14 and the steam generating unit is not subject to this subpart.

This subpart does not apply to this facility.

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

(1) Section 60.44b(f).

(2) Section 60.44b(g).

(3) Section 60.49b(a)(4).

All noted.

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

The subpart does not apply to this facility because the facility does not have any solid waste incinerator units or municipal waste combustion units.

(i) Affected facilities (i.e., heat recovery steam generators) that are associated with stationary combustion turbines and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. This subpart will continue to apply to all other affected facilities (i.e. heat recovery steam generators with duct burners) that are capable of combusting more than 29 MW (100 MMBtu/h) heat input of fossil fuel. If the affected facility (i.e. heat recovery steam generator) is subject to this subpart, only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. (The stationary combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part.)

The subpart does not apply to this facility because the facility does not have any stationary combustion turbines.

(j) Any affected facility meeting the applicability requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D (Standards of Performance for Fossil-Fuel-Fired Steam Generators, §60.40).

The subpart is not applicable to the facility as the Wellons boiler is fueled by biomass consisting of solely wood waste.

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

The subpart is not applicable to the facility as the facility does not have a municipal waste combustor.

(l) Affected facilities that also meet the applicability requirements under subpart BB of this part (Standards of Performance for Kraft Pulp Mills) are subject to the SO_2 and NO_X standards under this subpart and the PM standards under subpart BB.

This subpart does not apply to this facility as it is not a Kraft Pulp Mill. The facility sizes and dries dimensional *lumber only.*

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

This subpart does not apply as the facility does not have a temporary boiler.

§60.42b .... Standard for Sulfur Dioxide (SO_2)

(a) Except as provided in paragraphs (b), (c), (d), or (j) of this section, on and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, that combusts coal or oil shall cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO_2 emission rate (90 percent reduction) and the emission limit determined according to the following formula:

This subpart does not apply, the Wellons boiler does not combust coal or oil.

§60.43b .... Standard for Particulate Matter (PM)

(a) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005 that combusts coal or combusts mixtures of coal with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

This subpart does not apply, the Wellons boiler does not combust coal.

(b) On and after the date on which the performance test is completed or required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts oil (or mixtures of oil with other fuels) and uses a conventional or emerging technology to reduce SO_2 emissions shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

This subpart does not apply, the Wellons boiler does not combust oil.

(c) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification on or before February 28, 2005, and that combusts wood, or wood with other fuels, except coal, shall cause to be discharged from that affected facility any gases that contain PM in excess of the following emission limits:

(1) 43 ng/J (0.10 lb/MMBtu) heat input if the affected facility has an annual capacity factor greater than 30 percent (0.30) for wood.

(2) 86 ng/J (0.20 lb/MMBtu) heat input if (i) The affected facility has an annual capacity factor of 30 percent (0.30) or less for wood;

(ii) Is subject to a federally enforceable requirement limiting operation of the affected facility to an annual capacity factor of 30 percent (0.30) or less for wood; and

(iii) Has a maximum heat input capacity of 73 MW (250 MMBtu/hr) or less.

The construction for the Wellons boiler commenced before February 28, 2005. This subpart applies.

(d) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts municipal-type solid waste or mixtures of municipal-type solid waste with other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of the following emission limits:

This subpart does not apply the facility does not combust municipal-type solid waste it mixtures of municipal-type solid waste with other fuels.

(e) For the purposes of this section, the annual capacity factor is determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or municipal-type solid waste, and other fuels, as applicable, by the potential heat input to the steam generating unit if the steam generating unit had been operated for 8,760 hours at the maximum heat input capacity.

The Wellons boiler has an annual capacity factor of 100% for wood.

(f) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts coal, oil, wood, or mixtures of these fuels with any other fuels shall cause to be discharged into the atmosphere any gases that exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. An owner or operator of an affected facility that elects to install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring PM emissions according to the requirements of this subpart and is subject to a federally enforceable PM limit of 0.030 lb/MMBtu or less is exempt from the opacity standard specified in this paragraph.

The Wellons boiler is subject to the 20 percent opacity (6-minute average) requirement of NSPS. It is also subject to the Idaho statutory opacity standard and the Boiler MACT opacity standard. The Wellons boiler will become subject to federally enforceable PM limit that is less than 0.030 lb/MMBtu through Boiler MACT but does not operate a continuous emissions monitoring system for measuring PM emissions. The Wellons is equipped with a continuous opacity monitoring system (COMS).

(g) The PM and opacity standards apply at all times, except during periods of startup, shutdown, or malfunction.

(h)(1) Except as provided in paragraphs (h)(2), (h)(3), (h)(4), (h)(5), and (h)(6) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commenced construction, reconstruction, or modification after February 28, 2005, and that combusts coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MMBtu) heat input,

This subpart does not apply as the construction of the Wellons boiler commenced before February 28, 2005.

(2) As an alternative to meeting the requirements of paragraph (h)(1) of this section, the owner or operator of an affected facility for which modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the initial performance test is completed or required to be completed under §60.8, no owner or operator of an affected facility that commences modification after February 28, 2005 shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of both:

This subpart does not apply as the construction of the Wellons boiler commenced before February 28, 2005.

(3) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity of 73 MW (250 MMBtu/h) or less shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 43 ng/J (0.10 lb/MMBtu) heat input.

The Wellons boiler combusts 100% wood and has max input capacity of 116 MMBtu/hr. The proposed PM emission limit is 0.02 lb/MMBtu for filterable PM, based on Boiler MACT. The proposed emissions comply with the standard.

(4) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that commences modification after February 28, 2005, and that combusts over 30 percent wood (by heat input) on an annual basis and has a maximum heat input capacity greater than 73 MW (250 MMBtu/h) shall cause to be discharged into the atmosphere from that affected facility any gases that contain PM in excess of 37 ng/J (0.085 lb/MMBtu) heat input.

This subpart does not apply as the construction of the Wellons boiler commenced before February 28, 2005, and the heat capacity is less than 250 MMBtu/hr.

(5) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility not located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.30 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

This subpart does not apply as the construction of the Wellons boiler commenced before February 28, 2005, and does not combust oil.

(6) On and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, an owner or operator of an affected facility located in a noncontinental area that commences construction, reconstruction, or modification after February 28, 2005, and that combusts only oil that contains no more than 0.5 weight percent sulfur, coke oven gas, a mixture of these fuels, or either fuel (or a mixture of these fuels) in combination with other fuels not subject to a PM standard in §60.43b and not using a post-combustion technology (except a wet scrubber) to reduce SO_2 or PM emissions is not subject to the PM limits in (h)(1) of this section.

This subpart does not apply as the construction of the Wellons boiler commenced before February 28, 2005, and does not combust oil.

§60.44b .... Standard for Nitrogen Oxides (NO_X)

(a) Except as provided under paragraphs (k) and (l) of this section, on and after the date on which the initial performance test is completed or is required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of the following emission limits:

The Wellons boiler is not subject to the NO_X standard, as it only combusts wood waste.

§60.45b .... Compliance and Performance Test Methods and Procedures for Sulfur Dioxide

(a) The SO_2 emission standards in §60.42b apply at all times. Facilities burning coke oven gas alone or in combination with any other gaseous fuels or distillate oil are allowed to exceed the limit 30 operating days per calendar year for SO_2 control system maintenance.

(b) In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A (including fuel certification and sampling) of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section. The 30-day notice required in §60.8(d) applies only to the initial performance test unless otherwise specified by the Administrator.

(c) The owner or operator of an affected facility shall conduct performance tests to determine compliance with the percent of potential SO_2 emission rate (% P_s) and the SO_2 emission rate (E_s) pursuant to §60.42b following the procedures listed below, except as provided under paragraph (d) and (k) of this section.

This subpart does not apply as §60.42b does not apply, the Wellons boiler only combusts wood waste.

§60.46b .... Compliance and Performance Test Methods and Procedures for Particulate Matter and Nitrogen Oxides

(a) The PM emission standards and opacity limits under §60.43b apply at all times except during periods of startup, shutdown, or malfunction. The NO_X emission standards under §60.44b apply at all times.

(b) Compliance with the PM emission standards under §60.43b shall be determined through performance testing as described in paragraph (d) of this section, except as provided in paragraph (i) of this section.

(c) Compliance with the NO_X emission standards under §60.44b shall be determined through performance testing under paragraph (e) or (f), or under paragraphs (g) and (h) of this section, as applicable.

This subpart does not apply as the Wellons boiler is not subject to the NO_X standard.

(d) To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

The Wellons boiler is subject to this subpart.

(1) Method 3A or 3B of appendix A-2 of this part is used for gas analysis when applying Method 5 of appendix A-3 of this part or Method 17 of appendix A-6 of this part.

The Wellons boiler is subject to this subpart.

(2) Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM as follows:

(i) Method 5 of appendix A of this part shall be used at affected facilities without wet flue gas desulfurization (FGD) systems; and

(ii) Method 17 of appendix A-6 of this part may be used at facilities with or without wet scrubber systems provided the stack gas temperature does not exceed a temperature of 160 °C (320 °F). The procedures of sections 8.1 and 11.1 of Method 5B of appendix A-3 of this part may be used in Method 17 of appendix A-6 of this part only if it is used after a wet FGD system. Do not use Method 17 of appendix A-6 of this part after wet FGD systems if the effluent is saturated or laden with water droplets.

(iii) Method 5B of appendix A of this part is to be used only after wet FGD systems.

The Wellons boiler is subject to this subpart.

(3) Method 1 of appendix A of this part is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes may be approved by the Administrator when necessitated by process variables or other factors.

The Wellons boiler is subject to this subpart.

(4) For Method 5 of appendix A of this part, the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160±14 °C (320±25 °F).

The Wellons boiler is subject to this subpart.

(5) For determination of PM emissions, the oxygen (O_2) or CO_2 sample is obtained simultaneously with each run of Method 5, 5B, or 17 of appendix A of this part by traversing the duct at the same sampling location.

The Wellons boiler is subject to this subpart.

(6) For each run using Method 5, 5B, or 17 of appendix A of this part, the emission rate expressed in ng/J heat input is determined using:

The Wellons boiler is subject to this subpart.

(i) The O_2 or CO_2 measurements and PM measurements obtained under this section;

(ii) The dry basis F factor; and

(iii) The dry basis emission rate calculation procedure contained in Method 19 of appendix A of this part.

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions.

The Wellons boiler is subject to this subpart.

(e) To determine compliance with the emission limits for NO_x required under §60.44b, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_x under §60.48(b).

This subpart does not apply as the Wellons boiler is not subject to the NO_X standard.

(f) To determine compliance with the emissions limits for NO_x required by §60.44b(a)(4) or §60.44b(l) for duct burners used in combined cycle systems, either of the procedures described in paragraph (f)(1) or (2) of this section may be used:

This subpart does not apply as the Wellons boiler is not subject to the NO_X standard.

(g) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall demonstrate the maximum heat input capacity of the steam generating unit by operating the facility at maximum capacity for 24 hours. The owner or operator of an affected facility shall determine the maximum heat input capacity using the heat loss method or the heat input method described in sections 5 and 7.3 of the ASME *Power Test Codes* 4.1 (incorporated by reference, see §60.17). This demonstration of maximum heat input capacity shall be made during the initial performance test for affected facilities that meet the criteria of §60.44b(j). It shall be made within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of each facility, for affected facilities meeting the criteria of §60.44b(k). Subsequent demonstrations may be required by the Administrator at any other time. If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer is used.

The Wellons wood-fired is not subject to NOx limits or testing, "Otherwise, the maximum heat input capacity provided by the manufacturer is used." applies.

(h) The owner or operator of an affected facility described in §60.44b(j) that has a heat input capacity greater than 73 MW (250 MMBtu/hr) shall:

This subpart does not apply as the heat input is less than 250 MMBtu/hr and the NO_X standard does not apply to the Wellons boiler.

(i) The owner or operator of an affected facility seeking to demonstrate compliance with the PM limit in paragraphs §60.43b(a)(4) or §60.43b(h)(5) shall follow the applicable procedures in §60.49b(r).

This subpart does not apply as the Wellons boiler does not combust coal or oil.

(j) In place of PM testing with Method 5 or 5B of appendix A-3 of this part, or Method 17 of appendix A-6 of this part, an owner or operator may elect to install, calibrate, maintain, and operate a CEMS for monitoring PM emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility who elects to continuously monitor PM emissions instead of conducting performance testing using Method 5 or 5B of appendix A-3 of this part or Method 17 of appendix A-6 of this part shall comply with the requirements specified in paragraphs (j)(1) through (j)(14) of this section.

This subpart does not apply as IFG does not intend to install a continuous PM monitor.

§60.47b .... Emission Monitoring for Sulfur Dioxide

The Wellons boiler is not subject to the SO_2 limit.

§60.48b .... Emission Monitoring for Particulate Matter and Nitrogen Oxides

(a) Except as provided in paragraph (j) of this section, the owner or operator of an affected facility subject to the opacity standard under §60.43b shall install, calibrate, maintain, and operate a continuous opacity monitoring systems (COMS) for measuring the opacity of emissions discharged to the atmosphere and record the output of the system. The owner or operator of an affected facility subject to an opacity standard under §60.43b and meeting the conditions under paragraphs (j)(1), (2), (3), (4), (5), or (6) of this section who elects not to use a COMS shall conduct a performance test using Method 9 of appendix A-4 of this part and the procedures in §60.11

to demonstrate compliance with the applicable limit in §60.43b by April 29, 2011, within 45 days of stopping use of an existing COMS, or within 180 days after initial startup of the facility, whichever is later, and shall comply with either paragraphs (a)(1), (a)(2), or (a)(3) of this section. The observation period for Method 9 of appendix A-4 of this part performance tests may be reduced from 3 hours to 60 minutes if all 6-minute averages are less than 10 percent and all individual 15-second observations are less than or equal to 20 percent during the initial 60 minutes of observation.

(1) Except as provided in paragraph (a)(2) and (a)(3) of this section, the owner or operator shall conduct subsequent Method 9 of appendix A-4 of this part performance tests using the procedures in paragraph (a) of this section according to the applicable schedule in paragraphs (a)(1)(i) through (a)(1)(iv) of this section, as determined by the most recent Method 9 of appendix A-4 of this part performance test results.

(i) If no visible emissions are observed, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 12 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(ii) If visible emissions are observed but the maximum 6-minute average opacity is less than or equal to 5 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 6 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later;

(iii) If the maximum 6-minute average opacity is greater than 5 percent but less than or equal to 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 3 calendar months from the date that the most recent performance test was conducted or within 45 days of the next day that fuel with an opacity standard is combusted, whichever is later; or

(iv) If the maximum 6-minute average opacity is greater than 10 percent, a subsequent Method 9 of appendix A-4 of this part performance test must be completed within 45 calendar days from the date that the most recent performance test was conducted.

(2) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 of this part performance tests, elect to perform subsequent monitoring using Method 22 of appendix A-7 of this part according to the procedures specified in paragraphs (a)(2)(i) and (ii) of this section.

(i) The owner or operator shall conduct 10 minute observations (during normal operation) each operating day the affected facility fires fuel for which an opacity standard is applicable using Method 22 of appendix A-7 of this part and demonstrate that the sum of the occurrences of any visible emissions is not in excess of 5 percent of the observation period (*i.e.,* 30 seconds per 10 minute period). If the sum of the occurrence of any visible emissions is greater than 30 seconds during the initial 10 minute observation, immediately conduct a 30 minute observation. If the sum of the occurrence of visible emissions is greater than 5 percent of the observation period (*i.e.,* 90 seconds per 30 minute period), the owner or operator shall either document and adjust the operation of the facility and demonstrate within 24 hours that the sum of the occurrence of visible emissions is equal to or less than 5 percent during a 30 minute observation (*i.e.,* 90 seconds) or conduct a new Method 9 of appendix A-4 of this part performance test using the procedures in paragraph (a) of this section within 45 calendar days according to the requirements in §60.46d(d)(7).

(ii) If no visible emissions are observed for 10 operating days during which an opacity standard is applicable, observations can be reduced to once every 7 operating days during which an opacity standard is applicable. If any visible emissions are observed, daily observations shall be resumed.

IFG is complying with all applicable opacity monitoring requirements including installation and operation of a COMS.

(3) If the maximum 6-minute opacity is less than 10 percent during the most recent Method 9 of appendix A-4 of this part performance test, the owner or operator may, as an alternative to performing subsequent Method 9 of appendix A-4 performance tests, elect to perform subsequent monitoring using a digital opacity compliance system according to a site-specific monitoring plan approved by the Administrator. The observations shall be similar, but not necessarily identical, to the requirements in paragraph (a)(2) of this section. For reference

purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA); Office of Air Quality and Planning Standards; Sector Policies and Programs Division; Measurement Policy Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods.

(b) Except as provided under paragraphs (g), (h), and (i) of this section, the owner or operator of an affected facility subject to a NO_x standard under §60.44b shall comply with either paragraphs (b)(1) or (b)(2) of this section.

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(c) The CEMS required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(d) The 1-hour average NO_x emission rates measured by the continuous NO_x monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(e) The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities combusting coal, wood or municipal-type solid waste, the span value for a COMS shall be between 60 and 80 percent.

The Wellons COMS is complying with this requirement.

(2) For affected facilities combusting coal, oil, or natural gas, the span value for NO_x is determined using one of the following procedures:

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(f) When NO_x emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of appendix A of this part, Method 7A of appendix A of this part, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each steam generating unit operating day, in at least 22 out of 30 successive steam generating unit operating days.

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(g) The owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less, and that has an annual capacity factor for residual oil having a nitrogen content of 0.30 weight percent or less, natural gas, distillate oil, gasified coal, or any mixture of these fuels, greater than 10 percent (0.10) shall:

This subpart does not apply as the Wellons boiler only combusts wood waste.

(h) The owner or operator of a duct burner, as described in §60.41b, that is subject to the NO_x standards in §60.44b(a)(4), §60.44b(e), or §60.44b(l) is not required to install or operate a continuous emissions monitoring system to measure NO_x emissions.

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(i) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) is not required to install or operate a CEMS for measuring NO_x emissions.

The Wellons boiler is not subject to the NO_X limit, this subpart does not apply.

(j) The owner or operator of an affected facility that meets the conditions in either paragraph (j)(1), (2), (3), (4), (5), (6), or (7) of this section is not required to install or operate a COMS if:

(1) The affected facility uses a PM CEMS to monitor PM emissions; or

(2) The affected facility burns only liquid (excluding residual oil) or gaseous fuels with potential SO_2 emissions rates of 26 ng/J (0.060 lb/MMBtu) or less and does not use a post-combustion technology to reduce SO_2 or PM emissions. The owner or operator must maintain fuel records of the sulfur content of the fuels burned, as described under §60.49b(r); or

(3) The affected facility burns coke oven gas alone or in combination with fuels meeting the criteria in paragraph (j)(2) of this section and does not use a post-combustion technology to reduce SO_2 or PM emissions; or

(4) The affected facility does not use post-combustion technology (except a wet scrubber) for reducing PM, SO_2, or carbon monoxide (CO) emissions, burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur, and is operated such that emissions of CO to the atmosphere from the affected facility are maintained at levels less than or equal to 0.15 lb/MMBtu on a steam generating unit operating day average basis. Owners and operators of affected facilities electing to comply with this paragraph must demonstrate compliance according to the procedures specified in paragraphs (j)(4)(i) through (iv) of this section; or

(i) You must monitor CO emissions using a CEMS according to the procedures specified in paragraphs (j)(4)(i)(A) through (D) of this section.

(A) The CO CEMS must be installed, certified, maintained, and operated according to the provisions in §60.58b(i)(3) of subpart Eb of this part.

(B) Each 1-hour CO emissions average is calculated using the data points generated by the CO CEMS expressed in parts per million by volume corrected to 3 percent oxygen (dry basis).

(C) At a minimum, valid 1-hour CO emissions averages must be obtained for at least 90 percent of the operating hours on a 30-day rolling average basis. The 1-hour averages are calculated using the data points required in §60.13(h)(2).

(D) Quarterly accuracy determinations and daily calibration drift tests for the CO CEMS must be performed in accordance with procedure 1 in appendix F of this part.

(ii) You must calculate the 1-hour average CO emissions levels for each steam generating unit operating day by multiplying the average hourly CO output concentration measured by the CO CEMS times the corresponding average hourly flue gas flow rate and divided by the corresponding average hourly heat input to the affected source. The 24-hour average CO emission level is determined by calculating the arithmetic average of the hourly CO emission levels computed for each steam generating unit operating day.

(iii) You must evaluate the preceding 24-hour average CO emission level each steam generating unit operating day excluding periods of affected source startup, shutdown, or malfunction. If the 24-hour average CO emission level is greater than 0.15 lb/MMBtu, you must initiate investigation of the relevant equipment and control systems within 24 hours of the first discovery of the high emission incident and, take the appropriate corrective action as soon as practicable to adjust control settings or repair equipment to reduce the 24-hour average CO emission level to 0.15 lb/MMBtu or less.

(iv) You must record the CO measurements and calculations performed according to paragraph (j)(4) of this section and any corrective actions taken. The record of corrective action taken must include the date and time during which the 24-hour average CO emission level was greater than 0.15 lb/MMBtu, and the date, time, and description of the corrective action.

(5) The affected facility uses a bag leak detection system to monitor the performance of a fabric filter (baghouse) according to the most current requirements in section §60.48Da of this part; or

(6) The affected facility uses an ESP as the primary PM control device and uses an ESP predictive model to monitor the performance of the ESP developed in accordance and operated according to the most current requirements in section §60.48Da of this part; or

(7) The affected facility burns only gaseous fuels or fuel oils that contain less than or equal to 0.30 weight percent sulfur and operates according to a written site-specific monitoring plan approved by the permitting authority. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard.

IFG plans to install and operate a COMS on the Wellons boiler. The other monitoring methods are not applicable.

(k) Owners or operators complying with the PM emission limit by using a PM CEMS must calibrate, maintain, operate, and record the output of the system for PM emissions discharged to the atmosphere as specified in §60.46b(j). The CEMS specified in paragraph §60.46b(j) shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

IFG does not intend to use a PM CEMS, this subpart is not applicable.

(l) An owner or operator of an affected facility that is subject to an opacity standard under §60.43b(f) is not required to operate a COMS provided that the unit burns only gaseous fuels and/or liquid fuels (excluding residue oil) with a potential SO_2 emissions rate no greater than 26 ng/J (0.060 lb/MMBtu), and the unit operates according to a written site-specific monitoring plan approved by the permitting authority is not required to operate a COMS. This monitoring plan must include procedures and criteria for establishing and monitoring specific parameters for the affected facility indicative of compliance with the opacity standard. For testing performed as part of this site-specific monitoring plan, the permitting authority may require as an alternative to the notification and reporting requirements specified in §§60.8 and 60.11 that the owner or operator submit any deviations with the excess emissions report required under §60.49b(h).

This subpart applies as the Wellons boiler only combusts wood waste.

§60.49b .... Reporting and Recordkeeping Requirements

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

This subpart is applicable to the Wellons boiler.

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

This subpart is applicable to the Wellons boiler.

(2) If applicable, a copy of any federally enforceable requirement that limits the annual capacity factor for any fuel or mixture of fuels under §60.42b(d)(1), §60.43b(a)(2), (a)(3)(iii), (c)(2)(ii), (d)(2)(iii), §60.44b(c), (d), (e), (i), (j), (k), §60.45b(d), (g), §60.46b(h), or §60.48b(i);

This subpart is not applicable to the Wellons boiler.

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

This subpart is applicable to the Wellons boiler.

(4) Notification that an emerging technology will be used for controlling emissions of SO_2. The Administrator will examine the description of the emerging technology and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42b(a) unless and until this determination is made by the Administrator.

This subpart is not applicable to the Wellons boiler.

(b) The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

This subpart applies to the Wellons boiler.

(c) The owner or operator of each affected facility subject to the NO_x standard in §60.44b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions in the provisions of §60.48b(g)(2) shall submit to the Administrator for approval a plan that identifies the operating conditions to be monitored in §60.48b(g)(2) and the records to be maintained in §60.49b(g). This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. An affected facility burning coke oven gas alone or in combination with other gaseous fuels or distillate oil shall submit this plan to the Administrator for approval within 360 days of the initial startup of the affected facility or by November 30, 2009, whichever date comes later. If the plan is approved, the owner or operator shall maintain records of predicted nitrogen oxide emission rates and the monitored operating conditions, including steam generating unit load, identified in the plan. The plan shall:

The subpart is not applicable as the Wellons boiler is not subject to the NO_X limit.

(d) Except as provided in paragraph (d)(2) of this section, the owner or operator of an affected facility shall record and maintain records as specified in paragraph (d)(1) of this section.

Applies to the Wellons boiler.

(1) The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, distillate oil, residual oil, natural gas, wood, and municipal-type solid waste for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

Applies to the Wellons boiler.

(2) As an alternative to meeting the requirements of paragraph (d)(1) of this section, the owner or operator of an affected facility that is subject to a federally enforceable permit restricting fuel use to a single fuel such that the facility is not required to continuously monitor any emissions (excluding opacity) or parameters indicative of emissions may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

(d), (d)(1),and (d)(2) all apply to the Wellons boiler.

(e) For an affected facility that combusts residual oil and meets the criteria under §60.46b(e)(4), §60.44b(j), or (k), the owner or operator shall maintain records of the nitrogen content of the residual oil combusted in the affected facility and calculate the average fuel nitrogen content for the reporting period. The nitrogen content shall be determined using ASTM Method D4629 (incorporated by reference, see §60.17), or fuel suppliers. If residual oil blends are being combusted, fuel nitrogen specifications may be prorated based on the ratio of residual oils of different nitrogen content in the fuel blend.

This subpart is not applicable as the Wellons boiler does not combust residual oil.

(f) For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the requirements specified in paragraphs (f)(1) through (3) of this section, as applicable to the visible emissions monitoring method used.

Applies to the Wellons boiler.

(1) For each performance test conducted using Method 9 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(1)(i) through (iii) of this section.

Applies to the Wellons boiler.

(i) Dates and time intervals of all opacity observation periods;

(ii) Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

(iii) Copies of all visible emission observer opacity field data sheets;

Applies to the Wellons boiler.

(2) For each performance test conducted using Method 22 of appendix A-4 of this part, the owner or operator shall keep the records including the information specified in paragraphs (f)(2)(i) through (iv) of this section.

(i) Dates and time intervals of all visible emissions observation periods;

(ii) Name and affiliation for each visible emission observer participating in the performance test;

(iii) Copies of all visible emission observer opacity field data sheets; and

(iv) Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

Applies to the Wellons boiler, however IFG does not plan to use Method 22 for opacity compliance for the Wellons boiler.

(3) For each digital opacity compliance system, the owner or operator shall maintain records and submit reports according to the requirements specified in the site-specific monitoring plan approved by the Administrator.

Applies to the Wellons boiler COMS.

(g) Except as provided under paragraph (p) of this section, the owner or operator of an affected facility subject to the NO_x standards under §60.44b shall maintain records of the following information for each steam generating unit operating day:

This subpart is not applicable to the Wellons boiler as the boiler is not subject to the NO_X limit.

(h) The owner or operator of any affected facility in any category listed in paragraphs (h)(1) or (2) of this section is required to submit excess emission reports for any excess emissions that occurred during the reporting period.

This subpart is applicable to IFG.

(1) Any affected facility subject to the opacity standards in §60.43b(f) or to the operating parameter monitoring requirements in §60.13(i)(1).

Applies to the Wellons boiler.

(2) Any affected facility that is subject to the NO_x standard of §60.44b, and that:

This subpart is not applicable as the boiler is not subject to the NO_X limit.

(3) For the purpose of §60.43b, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards under §60.43b(f).

Applies to the Wellons boiler.

(4) For purposes of §60.48b(g)(1), excess emissions are defined as any calculated 30-day rolling average NO_x emission rate, as determined under §60.46b(e), that exceeds the applicable emission limits in §60.44b.

This subpart is not applicable as the boiler is not subject to the NO_X limit.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x under §60.48(b) shall submit reports containing the information recorded under paragraph (g) of this section.

This subpart is not applicable as the boiler is not subject to the NO_X limit.

(j) The owner or operator of any affected facility subject to the SO_2 standards under §60.42b shall submit reports.

This subpart is not applicable as the boiler is not subject to the SO_2 limit.

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b and the reporting requirement in paragraph (j) of this section, the following information shall be reported to the

Administrator:

This subpart is not applicable as the boiler is not subject to the SO_2 limit.

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) and the reporting requirements of paragraph (j) of this section, the following information shall be reported to the Administrator:

This subpart is not applicable as the boiler is not subject to the SO_2 limit.

(m) For each affected facility subject to the SO_2 standards in §60.42(b) for which the minimum amount of data required in §60.47b(c) were not obtained during the reporting period, the following information is reported to the Administrator in addition to that required under paragraph (k) of this section:

This subpart is not applicable as the boiler is not subject to the SO_2 limit.

(n) If a percent removal efficiency by fuel pretreatment (*i.e.*, $\%R_f$) is used to determine the overall percent reduction (*i.e.*, $\%R_o$) under §60.45b, the owner or operator of the affected facility shall submit a signed statement with the report.

This subpart is not applicable as the boiler is not subject to the SO_2 limit.

(o) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

This subpart is applicable to IFG.

(p) The owner or operator of an affected facility described in §60.44b(j) or (k) shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date;

(2) The number of hours of operation; and

(3) A record of the hourly steam load.

(p), (p)(1), (p)(2), and (p)(3) subparts are all applicable to IFG.

(q) The owner or operator of an affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator a report containing:

This subpart is applicable to IFG.

(1) The annual capacity factor over the previous 12 months;

This subpart is applicable to IFG.

(2) The average fuel nitrogen content during the reporting period, if residual oil was fired; and

This subpart is not applicable to IFG.

(3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_x emission tests required during the reporting period, the hours of operation during the reporting period, and the hours of operation since the last NO_x emission test.

This subpart is not applicable to IFG.

(r) The owner or operator of an affected facility who elects to use the fuel based compliance alternatives in §60.42b or §60.43b shall either:

This subpart is not applicable to IFG. IFG elected not to use the fuel based compliance alternatives.

(s) Facility specific NO_x standard for Cytec Industries Fortier Plant's C.AOG incinerator located in Westwego, Louisiana:

This subpart is not applicable to IFG.

(t) Facility-specific NO_x standard for Rohm and Haas Kentucky Incorporated's Boiler No. 100 located in Louisville, Kentucky:

This subpart is not applicable to IFG.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* (1) This paragraph (u) applies only to the pharmaceutical manufacturing facility, commonly referred to as the Stonewall Plant, located at Route 340 South, in Elkton, Virginia ("site") and only to the natural gas-fired boilers installed as part of the powerhouse conversion required pursuant to 40 CFR 52.2454(g). The requirements of this paragraph shall apply, and the requirements of §§60.40b through 60.49b(t) shall not apply, to the natural gas-fired boilers installed pursuant to 40 CFR 52.2454(g).

This subpart is not applicable to IFG.

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under paragraphs (h), (i), (j), (k) or (l) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

This subpart is not applicable to IFG.

(w) The reporting period for the reports required under this subpart is each 6 month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

IFG is subject to this subpart.

(x) Facility-specific NO_x standard for Weyerhaeuser Company's No. 2 Power Boiler located in New Bern, North Carolina:

This subpart is not applicable to IFG.

(y) Facility-specific NO_x standard for INEOS USA's AOGI located in Lima, Ohio:

This subpart is not applicable to IFG.

NESHAP Applicability (40 CFR 61)

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

MACT Applicability (40 CFR 63)

The facility has proposed to operate as a major source of hazardous air pollutant (HAP) emissions, and is subject to the requirements of 40 CFR 63, Subpart DDDD–National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products, DEQ is delegated this Subpart. 40 CFR 63, Subpart DDDDD–National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, DEQ is delegated this Subpart. 40 CFR 63, Subpart ZZZZ–National Emission Standards for Hazardous Air Pollutants: Stationary Reciprocating Internal Combustion Engines, DEQ is delegated this Subpart. Refer to the Title V Classification section for additional information.

- 40 CFR 63, Subpart DDDD - National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products. DEQ is delegated this Subpart.
- 40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. DEQ is delegated this Subpart.
- 40 CFR 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. DEQ is delegated this Subpart.

40 CFR 63, Subpart DDDD................................. National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products

§63.2230.. What is the purpose of this subpart?

This subpart establishes national compliance options, operating requirements, and work practice requirements for hazardous air pollutants (HAP) emitted from plywood and composite wood products (PCWP) manufacturing facilities. This subpart also establishes requirements to demonstrate initial and continuous compliance with the compliance options, operating requirements, and work practice requirements.

§63.2231.. Does this subpart apply to me?

This subpart applies to you if you meet the criteria in paragraphs (a) and (b) of this section.

(a) You own or operate a PCWP manufacturing facility. A PCWP manufacturing facility is a facility that manufactures plywood and/or composite wood products by bonding wood material (fibers, particles, strands, veneers, etc.) or agricultural fiber, generally with resin under heat and pressure, to form a structural panel or engineered wood product. Plywood and composite wood products manufacturing facilities also include facilities that manufacture dry veneer and lumber kilns located at any facility. Plywood and composite wood products include, but are not limited to, plywood, veneer, particleboard, oriented strandboard, hardboard, fiberboard, medium density fiberboard, laminated strand lumber, laminated veneer lumber, wood I-joists, kiln-dried lumber, and glue-laminated beams.

(b) The PCWP manufacturing facility is located at a major source of HAP emissions. A major source of HAP emissions is any stationary source or group of stationary sources within a contiguous area and under common control that emits or has the potential to emit any single HAP at a rate of 9.07 megagrams (10 tons) or more per year or any combination of HAP at a rate of 22.68 megagrams (25 tons) or more per year.

This subpart is applicable to IFG. After the issuance of this permit IFG will become a HAP major source. IFG has five lumber dry kilns on-site and is therefore, affected by this subpart.

§63.2232.. What parts of my plant does this subpart cover?

(a) This subpart applies to each new, reconstructed, or existing affected source at a PCWP manufacturing facility.

(b) The affected source is the collection of dryers, refiners, blenders, formers, presses, board coolers, and other process units associated with the manufacturing of plywood and composite wood products. The affected source includes, but is not limited to, green end operations, refining, drying operations (including any combustion unit exhaust stream routinely used to direct fire process unit(s)), resin preparation, blending and forming operations, pressing and board cooling operations, and miscellaneous finishing operations (such as sanding, sawing, patching, edge sealing, and other finishing operations not subject to other national emission standards for hazardous air pollutants (NESHAP)). The affected source also includes onsite storage and preparation of raw materials used in the manufacture of plywood and/or composite wood products, such as resins; onsite wastewater treatment operations specifically associated with plywood and composite wood products manufacturing; and miscellaneous coating operations (§63.2292). The affected source includes lumber kilns at PCWP manufacturing facilities and at any other kind of facility.

This subpart is applicable to IFG.

(c) An affected source is a new affected source if you commenced construction of the affected source after January 9, 2003, and you meet the applicability criteria at the time you commenced construction.

This subpart is applicable to IFG.

(d) An affected source is reconstructed if you meet the criteria as defined in §63.2.

This subpart is not applicable to IFG.

(e) An affected source is existing if it is not new or reconstructed.

This subpart is applicable to IFG.

§63.2233.. When do I have to comply with this subpart?

(a) If you have a new or reconstructed affected source, you must comply with this subpart according to paragraph (a)(1) or (2) of this section, whichever is applicable.

This subpart is not applicable to IFG.

(1) If the initial startup of your affected source is before September 28, 2004, then you must comply with the compliance options, operating requirements, and work practice requirements for new and reconstructed sources in this subpart no later than September 28, 2004.

This subpart is not applicable to IFG.

(2) If the initial startup of your affected source is after September 28, 2004, then you must comply with the compliance options, operating requirements, and work practice requirements for new and reconstructed sources in this subpart upon initial startup of your affected source.

This subpart is not applicable to IFG.

(b) If you have an existing affected source, you must comply with the compliance options, operating requirements, and work practice requirements for existing sources no later than October 1, 2007.

This subpart is not applicable to IFG.

(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, you must be in compliance with this subpart by October 1, 2007 or upon initial startup of your affected source as a major source, whichever is later.

This subpart is applicable to IFG.

(d) You must meet the notification requirements according to the schedule in §63.2280 and according to 40 CFR part 63, subpart A. Some of the notifications must be submitted before you are required to comply with the compliance options, operating requirements, and work practice requirements in this subpart.

This subpart is not applicable to IFG.

§63.2240 .... What are the compliance options and operating requirements and how must I meet them?

This subpart is not applicable to IFG.

§63.2252 .... What are the requirements for process units that have no control or work practice requirements?

For process units not subject to the compliance options or work practice requirements specified in §63.2240 (including, but not limited to, lumber kilns), you are not required to comply with the compliance options, work practice requirements, performance testing, monitoring, SSM plans, and recordkeeping or reporting requirements of this subpart, or any other requirements in subpart A of this part, except for the initial notification requirements in §63.9(b).

This subpart is applicable to IFG.

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

§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.

After the issuance of this permit IFG will be a HAP major source and applicable to this subpart.

§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.

This subpart applies to the Wellons boiler.

(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.

This subpart applies to the Wellons boiler.

(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.

This subpart does not apply to the Wellons boiler.

(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.

This subpart does not apply to the Wellons boiler.

(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.

This subpart does not apply to the Wellons boiler.

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

This subpart applies to the Wellons boiler. The Wellons boiler was constructed before June 4, 2010
It is not reconstructed because it has not been re-built. The Wellons boiler is an existing fuel cell boiler for purposes or Subpart DDDDD.

(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.

This subpart does not apply to the Wellons boiler.

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

There are no boilers or process heaters located at the IFG – Grangeville facility that are not subject to this subpart.

§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 April 1, 2013, or upon startup of your boiler or process heater, whichever is later.

This subpart does not apply to the Wellons boiler.

(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).

This subpart does not apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

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

This subpart does not apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

(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 and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of §60.2145(a)(2) and (3) or §60.2710(a)(2) and (3).

This subpart does not apply to the Wellons boiler.

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2016, 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.

This subpart does not apply to the Wellons boiler.

(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.

This subpart does not apply to the Wellons boiler.

(h) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory after the compliance date of this subpart, you must be in compliance with the applicable existing source provisions of this subpart on the effective date of the fuel switch or physical change.

This subpart does not apply to the Wellons boiler.

(i) If you own or operate a new industrial, commercial, or institutional boiler or process heater and have switched fuels or made a physical change to the boiler or process heater that resulted in the applicability of a different subcategory, you must be in compliance with the applicable new source provisions of this subpart on the effective date of the fuel switch or physical change.

This subpart does not apply to the Wellons boiler.

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

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

This subpart does apply to the Wellons boiler.

§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 either steam, cogenerate steam with electricity, or both. 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 only electricity. Boilers that perform multiple functions (cogeneration and electricity generation) or supply steam to common headers would calculate a total steam energy output using equation 21 of §63.7575 to demonstrate compliance with the output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart. 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 (iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

This subpart does apply to the Wellons boiler.

(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.

This subpart does not apply to the Wellons boiler.

(ii) If your boiler or process heater commenced construction or reconstruction on or 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.

This subpart does not apply to the Wellons boiler.

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

This subpart does not apply to the Wellons boiler.

(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).

This subpart does apply to the Wellons boiler.

(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 subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler if elected by IFG.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

This subpart does not apply to the Wellons boiler. IFG does not have any limited-use boilers or process heaters.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in §63.7540.

This subpart does not apply to the Wellons boiler, the heat input capacity is greater than 5 MMBtu/hr and only combusts wood waste.

(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 must complete a tune-up every 5 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in §63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

This subpart does not apply to the Wellons boiler; the heat input capacity is greater than 5 MMBtu/hr.

(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 items 5 and 6 of Table 3 to this subpart.

This subpart does apply to the Wellons boiler.

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters

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…	Or 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 designed to burn solid fuel	a. HCl	2.2E-02 lb per MMBtu of heat input	2.5E-02 lb per MMBtu of steam output or 0.27 lb per MWh	For M26A, Collect a minimum of 1 dscm 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.
12. Fuel cell units designed to burn biomass/bio-based solid	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen	2.4 lb per MMBtu of steam output or 12 lb per MWh	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E-02 lb per MMBtu of heat input; or (5.8E-03 lb per MMBtu of heat input)	5.5E-02 lb per MMBtu of steam output or 2.8E-01 lb per MWh; or (1.6E-02 lb per MMBtu of steam output or 8.1E-02 lb per MWh)	Collect a minimum of 2 dscm per run.

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.

Table 3 to Subpart DDDDD of Part 63—Work Practice Standards

As stated in §63.7500, you must comply with the following applicable work practice standards:

If your unit is…	You must comply with 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	Conduct a tune-up of the boiler or process heater every 5 years as specified in §63.7540.
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	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	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 operated under an energy management program developed according to the ENERGY STAR guidelines for energy management or compatible with ISO 50001 for at least one year between January 1, 2008 and the compliance date specified in §63.7495 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. 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. 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. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified. f. f. A list of cost-effective energy conservation measures that are within the facility's control. g. g. A list of the energy savings potential of the energy conservation measures identified. h. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

If your unit is…	You must comply with the following…
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	a. You must operate all CMS during startup. b. 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, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, liquefied petroleum gas, clean dry biomass, and any fuels meeting the appropriate HCl, mercury and TSM emission standards by fuel analysis. c. You have the option of complying using either of the following work practice standards. (1) If you choose to comply using definition (1) of "startup" in §63.7575, once you start firing fuels that are not clean fuels, 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, and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose, OR (2) If you choose to comply using definition (2) of "startup" in §63.7575, once you start to feed fuels that are not clean fuels, you must vent emissions to the main stack(s) and engage all of the applicable control devices so as to comply with the emission limits within 4 hours of start of supplying useful thermal energy. You must engage and operate PM control within one hour of first feeding fuels that are not clean fuels[a]. You must start all applicable control devices as expeditiously as possible, but, in any case, when necessary to comply with other standards applicable to the source by a permit limit or a rule other than this subpart that require operation of the control devices. You must develop and implement a written startup and shutdown plan, as specified in §63.7505(e). d. You must comply with all applicable emission limits at all times except during startup and shutdown periods at which time you must meet 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	You must operate all CMS during shutdown. While firing fuels that are not clean fuels 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, and SCR but, in any case, when necessary to comply with other standards applicable to the source that require operation of the control device. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the following clean fuels: Natural gas, synthetic natural gas, propane, other Gas 1 fuels, distillate oil, syngas, ultra-low sulfur diesel, refinery gas, and liquefied petroleum gas. 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.

[a)] As specified in §63.7555(d)(13), the source may request an alternative timeframe with the PM controls requirement to the permitting authority (state, local, or tribal agency) that has been delegated authority for this subpart by EPA. The source must provide evidence that (1) it is unable to safely engage and operate the PM control(s) to meet the "fuel firing + 1 hour" requirement and (2) the PM control device is appropriately designed and sized to meet the filterable PM emission limit. It is acknowledged that there may be another control device that has been installed other than ESP that provides additional PM control (*e.g.*, scrubber).

Table 4 to Subpart DDDDD of Part 63—Operating Limits for Boilers and Process Heaters

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 . . .
4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS	a. This option is for boilers and process heaters that operate dry control systems (*i.e.*, an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation (daily block average).
7. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the 30-day rolling average operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test.
8. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer 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 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).

§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 emission and operating limits apply to you at all times the affected unit is operating except for the periods noted in §63.7500(f).

This subpart does apply to the Wellons boiler.

(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), 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 stack testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

This subpart does apply to the Wellons boiler.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits through 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).

This subpart does apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

(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).

This subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler.

(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).

This subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler.

(e) If you have an applicable emission limit, and you choose to comply using definition (2) of "startup" in §63.7575, you must develop and implement a written startup and shutdown plan (SSP) according to the requirements in Table 3 to this subpart. The SSP must be maintained onsite and available upon request for public inspection.

This subpart does apply to the Wellons boiler.

§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 (stack) testing, your initial compliance requirements include all the following:

This subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

(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 Gas 1 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 non-Gas 1 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 non-Gas 1 fuels according to §63.7521 and Table 6 to this subpart.

This subpart does apply to the Wellons boiler.

(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.

This subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler.

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

This subpart does apply to the Wellons boiler.

IFG plans to perform stack testing for PM, CO, HCl and Hg, analyze the hog fuel for heating value, establish operating limits and conduct CMS performance evaluations for the COMS, oxygen monitor and steam flow monitor.

(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.

This subpart does apply to the Wellons boiler.

If IFG choses to show compliance with HCl, Hg, or TSM through fuel analysis, they will follow these requirements.

(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 1, 2, 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.

This subpart does apply to the Wellons boiler.

IFG plans to demonstrate CO compliance with source testing. There are no plans for a CO CEMS.

(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.

This subpart does apply to the Wellons boiler.

IFG plans to conduct a PM source test as required.

(e) For existing affected sources (as defined in §63.7490), you must complete the initial compliance demonstrations, 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.

This subpart does apply to the Wellons boiler.

IFG will complete the initial compliance demonstrations no later than 180 days after the compliance date, which will be 3 years after the permit is issued.

(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 subpart does not apply to the Wellons boiler.

(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 §63.7515(d) 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 §63.7515(d).

This subpart does not apply to the Wellons 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.

This subpart does not apply to the Wellons boiler.

(i) For an existing EGU that becomes subject after January 31, 2016, you must demonstrate compliance within 180 days after becoming an affected source.

This subpart does not apply to the Wellons boiler.

(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 subpart does not apply to the Wellons boiler.

(k) For affected sources, as defined in §63.7490, that switch subcategories consistent with §63.7545(h) after the initial compliance date, you must demonstrate compliance within 60 days of the effective date of the switch, unless you had previously conducted your compliance demonstration for this subcategory within the previous 12 months.

This subpart does not apply to the Wellons boiler.

§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.

This subpart does apply to the Wellons boiler. IFG will perform performance tests each of the first two years after the compliance date.

(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 subpart does apply to the Wellons boiler. IFG plans to complete subsequent performance tests on the modified schedule if allowed. IFG plans to do stack tests for HCl and Hg. The Wellons boiler will only burn one fuel, so the maximum input level requirements are automatically met.

(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 subpart does apply to the Wellons boiler.

(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 April 1, 2013, or the initial startup of the new or reconstructed affected source, whichever is later.

This subpart does apply to the Wellons boiler. The initial tune-up for the Wellons boiler was completed under the requirements of Subpart JJJJJJ. IFG will modify the tune-up schedule after the Subpart DDDDD compliance date.

(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 sampling is conducted on one day per month, samples should be no less than 14 days apart, but if multiple samples are taken per month, the 14-day restriction does not apply.

This subpart does apply to the Wellons boiler. IFG is aware of these requirements and will follow them if they ever decide to use fuel analysis to demonstrate Hg or HCl compliance.

(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.

This subpart does apply to the Wellons boiler. IFG will submit the performance test reports within the required timeframe.

(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 subpart does not apply to the Wellons boiler.

(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 (stack tests or fuel analyses) 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.

This subpart does not apply to the Wellons boiler.

(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).

This subpart does not apply to the Wellons boiler.

§63.7520 .... What stack tests and procedures must I use?

This subpart does apply to the Wellons boiler. IFG will follow all the performance testing requirements as described in this section. The exact requirements will be taken directly from the regulation.

(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.

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

(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.

(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.

(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.

(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.

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:

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
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	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 TSM emission concentration	Method 29 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.
3. Hydrogen chloride	a. Select sampling ports location and the number of traverse points	Method 1 at 40 CFR part 60, appendix A-1 of this chapter.

To conduct a performance test for the following pollutant . . .	You must. . .	Using, as appropriate . . .
	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	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.

a) Incorporated by reference, see §63.14.

Table 7 to Subpart DDDDD of Part 63—Establishing Operating Limits[ab]

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. PM, TSM, or mercury	c. Opacity	i. Establish a site-specific maximum opacity level	(1) Data from the opacity monitoring system during the PM performance test	(a) You must collect opacity readings every 15 minutes during the entire period of the performance tests. (b) Determine the average

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				hourly opacity reading for each performance test run by computing the hourly averages using all of the 15-minute readings taken during each performance test run. (c) Determine the highest hourly average opacity reading measured during the test run demonstrating compliance with the PM (or TSM) emission limitation.
4. Carbon monoxide for which compliance is demonstrated by a performance test	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to §63.7530(b)	(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 highest hourly average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

a) Operating limits must be confirmed or reestablished during performance tests.

b) If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests. 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.

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

This subpart does apply to the Wellons boiler. IFG does not intend to use fuel analyses to demonstrate compliance. If this plan changes, IFG will follow the requirements of this section directly from the regulation.

Table 6 to Subpart DDDDD of Part 63—Fuel Analysis Requirements

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), 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[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722[a] (for coal), EPA SW-846-7471B[a] or EPA 1631 or EPA 1631E[a] (for solid samples), or EPA SW-846-7470A[a] or EPA SW-846-7471B[a] (for liquid samples), or EPA 821-R-01-013[a] (for liquid or solid), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content	For fuel mixtures use Equation 8 in §63.7530.
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), 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[a], 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 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	For fuel mixtures use Equation 7 in §63.7530 and convert from chlorine to HCl by multiplying by 1.028.
4. TSM	a. Collect fuel samples	Procedure in §63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
		D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or 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), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[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), 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] 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 TSM concentration in fuel sample	ASTM D3683[a], or ASTM D4606[a], or ASTM D6357[a] or EPA 200.8[a] or EPA SW-846-6020[a], or EPA SW-846-6020A[a], or EPA SW-846-6010C[a], EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW-846-7740[a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content	For fuel mixtures use Equation 9 in §63.7530.

a) Incorporated by reference, see §63.14.

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

This subpart does apply to the Wellons boiler, however IFG only has one boiler, so averaging is not relevant.

§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 (or carbon dioxide (CO_2)) according to the procedures in paragraphs (a)(1) through (6) of this section.

This subpart does apply to the Wellons boiler. IFG plans to demonstrate CO compliance through performance testing and to install and operate an oxygen analyzer system on the Wellons boiler. The procedures in (a)(1) through (6) of this section do not apply.

(1) Install the CO CEMS and oxygen (or CO_2) analyzer by the compliance date specified in §63.7495. The CO and oxygen (or CO_2) levels shall be monitored at the same location at the outlet of the boiler or process heater. An owner or operator may request an alternative test method under §63.7 of this chapter, in order that compliance with the CO emissions limit be determined using CO_2 as a diluent correction in place of oxygen at 3 percent. EPA Method 19 F-factors and EPA Method 19 equations must be used to generate the appropriate CO_2 correction percentage for the fuel type burned in the unit, and must also take into account that the 3 percent oxygen correction is to be done on a dry basis. The alternative test method request must account for any CO_2 being added to, or removed from, the emissions gas stream as a result of limestone injection, scrubber media, etc.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B; part 75 of this chapter (if an CO_2 analyzer is used); the site-specific monitoring plan developed according to §63.7505(d); and the requirements in §63.7540(a)(8) and paragraph (a) of this section. Any boiler or

process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to §63.7505(d), and the requirements in §63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in §63.8(e) and according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A-4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with §63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(vi) When CO_2 is used to correct CO emissions and CO_2 is measured on a wet basis, correct for moisture as follows: Install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating CO concentrations. The following continuous moisture monitoring systems are acceptable: A continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, *i.e.*, a psychrometric chart (for saturated gas streams following wet scrubbers or other demonstrably saturated gas streams, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (*e.g.*, hourly average wet-and dry basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

(3) Complete a minimum of one cycle of CO and oxygen (or CO_2) CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen (or CO_2) data concurrently. Collect at least four CO and oxygen (or CO_2) CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in §63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen (or corrected to an CO_2 percentage determined to be equivalent to 3 percent oxygen) from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19-19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A-7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

This subpart does apply to the Wellons boiler. If IFG installs a trim system, they will comply.

(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, 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, and 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.

This subpart does not apply to the Wellons boiler

(1) Install, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must have a documented detection limit of 0.5 milligram per actual cubic meter, or less.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with §63.7505(d), the requirements in §63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of §60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A-3 or Method 17 at 40 CFR part 60, appendix A-6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in §63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(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.

This subpart does apply to the Wellons boiler. IFG operates a COMS on the Wellons boiler stack as required by NSPS Subpart Db, which also complies with this section.

(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.

(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.

This subpart does not apply to the Wellons boiler

(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.

(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.

This subpart does not apply to the Wellons boiler. IFG will not use a stack flow monitoring system.

(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.

(f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

This subpart does not apply to the Wellons boiler

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

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

This subpart does not apply to the Wellons boiler

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Calibrate the pH monitoring system in accordance with your monitoring plan and according to the manufacturer's instructions. Clean the pH probe at least once each process operating day. Maintain on-site documentation that your calibration frequency is sufficient to maintain the specified accuracy of your device.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

This subpart does not apply to the Wellons boiler. The Wellons boiler has an ESP but not a wet scrubber.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

This subpart does not apply to the Wellons boiler

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

This subpart does not apply to the Wellons boiler

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA-454/R-98-015 (incorporated by reference, see §63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

This subpart does not apply to the Wellons boiler

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the FEDERAL REGISTER or the date of approval of a site-specific monitoring plan.

This subpart does not apply to the Wellons boiler

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in §63.7540(a)(14) for a mercury CEMS and §63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A-7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect 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.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide (SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you elect to use an SO_2 CEMS to demonstrate continuous compliance with the HCl emission limit, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to either part 60 or part 75 of this chapter.

This subpart does not apply to the Wellons boiler

(1) The SO_2 CEMS must be installed by the compliance date specified in §63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet either the applicable daily and quarterly requirements in Procedure 1 of appendix F of part 60 or the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in §63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in §63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in §63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias

adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

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

This entire section is applicable to IFG. IFG will meet the requirements of this section §63.7530 and all subparts within.

(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). 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 stack 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).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(2) You must establish the maximum mercury fuel input level (Mercury input) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} \left(HGi \times Qi \right) \qquad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content during the initial compliance test. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} \left(TSMi \times Qi \right) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to §63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM during the initial compliance test. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of “1” for Qi. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(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.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in §63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4-20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (e.g., when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{X} = \frac{1}{n}\sum_{i=1}^{n} X_1, \bar{Y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30\text{-day} = \frac{\sum_{i=1}^{n} Hpvi}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 30 operating days.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers ("back half") of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the "back half" for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (*e.g.* beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run.

(iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in §63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iv) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(v) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in §63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit
(vii) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in §63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.
(viii) 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.
(ix) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in §63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.(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.
(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.

(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.

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

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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.

(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.

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

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(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.

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

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 15 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. For continuous compliance demonstration, the actual fraction of the fuel burned during the month should be used.

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

(d)[Reserved]

(e) You must include with the Notification of Compliance Status a signed certification that either the energy assessment was completed according to Table 3 to this subpart, and that the assessment is an accurate depiction of your facility at the time of the assessment, or that the maximum number of on-site technical hours specified in the definition of energy assessment applicable to the facility has been expended.

(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).

(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.

(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 items 5 and 6 of Table 3 of this subpart.

(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) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with §63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by collecting the maximum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the HCl performance test.

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

This subpart applies to IFG, however IFG does not plan to use energy credits.

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

This entire subpart applies to IFG. IFG will collect and maintain the required monitoring data as described in this section.

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

(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.

(c) You may not use data recorded during periods of startup and shutdown, 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.

(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 of startup and shutdown, 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 semi-annual report.

§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.

This subpart applies to IFG. IFG will comply with the applicable portions of this section, as detailed in the regulation.

(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 §63.7555(d), 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) Equal to or lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Equal to or 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.

(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, you must recalculate the HCl emission rate using Equation 16 of §63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required

to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 16 of §63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(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, you must recalculate the maximum chlorine input using Equation 7 of §63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of §63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in §63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 17 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 17 of §63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(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, you must recalculate the maximum mercury input using Equation 8 of §63.7530. If the results of recalculating the maximum mercury input using Equation 8 of §63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is subject to numeric emission limits.

(iii) Keep records of CO levels according to §63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(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).

(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. You must conduct the tune-up while burning the type of fuel (or fuels in case of units that routinely burn a mixture) that provided the majority of the heat input to the boiler or process heater over the 12 months prior to the tune-up. 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.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or 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, a 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.

(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 an oxygen trim system is utilized on a unit without emission standards to reduce the tune-up frequency to once every 5 years, set the oxygen level no lower than the oxygen concentration measured during the most recent tune-up.

(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.

(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 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for mercury CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for mercury CEMS. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(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.

(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.

(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 30 operating days if you specified a 30 operating day basis in §63.7545(e)(2)(iii) for HCl CEMS or it must be 720 hours if you specified a 720 hour basis in §63.7545(e)(2)(iii) for HCl CEMS. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(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.

(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, you must recalculate the maximum TSM input using Equation 9 of §63.7530. If the results of recalculating the maximum TSM input using Equation 9 of §63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in §63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in §63.7530(b). You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(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, you must recalculate the TSM emission rate using Equation 18 of §63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in §63.7510(a)(2)(i) through (iii). You may exclude the fuels described in §63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to §63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 18 of §63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(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) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (v) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(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 subpart applies to IFG. IFG will report any deviations as required.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in §63.7521(f) through (i).

This subpart does not apply.

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in §63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in §63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart.

This subpart does apply, IFG will meet the practice standards as required.

Table 8 to Subpart DDDDD of Part 63—Demonstrating Continuous Compliance

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 daily block average opacity to less than or equal to 10 percent or the highest hourly average opacity reading measured during the performance test run demonstrating compliance with the PM (or TSM) emission limitation.
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.
	d. Calculate the HCI, mercury, and/or TSM emission rate from the boiler or process heater in units of lb/MMBtu using Equation 15 and Equations 17, 18, and/or 19 in §63.7530.
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)(7).
	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 CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the performance test according to §63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to §63.7525;
	b. Reducing the data to 30-day rolling averages; and
	c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the highest hourly SO_2 rate measured during the HCl performance test according to §63.7530.

§63.7541 .... How do I demonstrate continuous compliance under the emissions averaging provision?

This subpart applies, however IFG does not intend to use emissions averaging provisions as there is only one boiler at the facility.

§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.

(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 subpart applies. IFG plans to submit the initial notification for the Wellons boiler within 120 days after issuance of the revised Tier I permit.

(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.

This subpart does not apply.

(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 subpart applies. IFG will provide the required notifications for each performance test as required.

(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) of this section, 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) of this section and must be submitted within 60 days of the compliance date specified at §63.7495(b).

This subpart applies. IFG will submit the notifications of compliance status as required. Details of the submittal are listed in the regulation.

(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.

(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:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(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,

(iii) Identification of whether you are complying the arithmetic mean of all valid hours of data from the previous 30 operating days or of the previous 720 hours. This identification shall be specified separately for each operating parameter.

(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.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(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:

(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.

(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.

(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:

(i) “This facility completed the required initial tune-up for all of the boilers and process heaters covered by 40 CFR part 63 subpart DDDDD at this site according to the procedures in §63.7540(a)(10)(i) through (vi).”

(ii) “This facility has had an energy assessment performed according to §63.7530(e).”

(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.”

(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, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in §63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

This subpart does not apply.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

This subpart does not apply.

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you have switched fuels or made a physical change to the boiler or process heater and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

This subpart applies, however IFG has no reason to think a physical change or fuel switch would ever occur at the Wellons boiler. If a physical change or fuel switch does occur the regulation will be followed directly.

(1) The name of the owner or operator of the affected source, as defined in §63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date upon which the fuel switch or physical change occurred.

§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 subpart applies. The only required report in Table 9 is the compliance report. The boiler MACT compliance report will be submitted with the Idaho Tier I Air Operating Permit annual and semi-annual reports, as required.

(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 subsequent annual, biennial, or 5-year tune-up according to §63.7540(a)(10), (11), or (12), respectively, and not subject to emission limits or Table 4 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.

This subpart applies; IFG has applicable requirements and will be submitting semi-annual reports with the Tier I permit reports. The DEQ semi-annual reports are due by July 30 and January 30, so there will be no change to the reporting dates.

(1) The first semi-annual 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 June 30 or December 31, whichever date is the first date that occurs at least 180 days after the compliance date that is specified for your source in §63.7495. If submitting an annual, biennial, or 5-year compliance report, 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 December 31 within 1, 2, or 5 years, as applicable, after the compliance date that is specified for your source in §63.7495.

(2) The first semi-annual 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.

(3) Each subsequent semi-annual 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. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent semi-annual 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. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the permitting authority has established dates for submitting semiannual reports pursuant to 70.6(a)(3)(iii)(A) or 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the permitting authority has established in the permit instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

This subpart applies.

(1) If the facility is subject to the requirements of a tune up you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii) of this section, (xiv) and (xvii) of this section, and paragraph (c)(5)(iv) of this section for limited-use boiler or process heater.

(2) If you are complying with the fuel analysis you must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (vi), (x), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(3) If you are complying with the applicable emissions limit with performance testing you must submit a compliance report with the information in (c)(5)(i) through (iii), (vi), (vii), (viii), (ix), (xi), (xiii), (xv), (xvii), (xviii) and paragraph (d) of this section.

(4) If you are complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (iii), (v), (vi), (xi) through (xiii), (xv) through (xviii), and paragraph (e) of this section.

(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.

(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 16 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 17 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 18 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).

(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.

(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).

(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.

(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.

(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.

(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.

(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).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values for CEMS (CO, HCl, SO_2, and mercury), 10 day rolling average values for CO CEMS when the limit is expressed as a 10 day instead of 30 day rolling average, and the PM CPMS data.

(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.

(xviii) For each instance of startup or shutdown include the information required to be monitored, collected, or recorded according to the requirements of §63.7555(d).

(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, or from the work practice standards for periods if startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

This subpart applies.
(1) A description of the deviation and which emission limit, operating limit, or work practice standard 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).

This subpart applies.

(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.

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

This subpart applies.

(1) Within 60 days after the date of completing each performance test (as defined in §63.2) required by this subpart, you must submit the results of the performance tests, including any fuel analyses, following the procedure specified in either paragraph (h)(1)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through use of the EPA's ERT or an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §63.13.

(2) Within 60 days after the date of completing each CEMS performance evaluation (as defined in 63.2), you must submit the results of the performance evaluation following the procedure specified in either paragraph (h)(2)(i) or (ii) of this section.

(i) For performance evaluations of continuous monitoring systems measuring relative accuracy test audit (RATA) pollutants that are supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) Performance evaluation data must be submitted in a file format generated through the use of the EPA's ERT or an alternate file format consistent with the XML schema listed on the EPA's ERT Web site. If you claim that some of the performance evaluation information being transmitted is CBI, you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For any performance evaluations of continuous monitoring systems measuring RATA pollutants that are not supported by the EPA's ERT as listed on the ERT Web site at the time of the evaluation, you must submit the results of the performance evaluation to the Administrator at the appropriate address listed in §63.13.

(3) You must submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX.) You must use the appropriate electronic report in CEDRI for this subpart. Instead of using the electronic report in CEDRI for this subpart, you may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §63.13. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI.

Table 9 to Subpart DDDDD of Part 63—Reporting Requirements

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	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).
	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 for periods of startup and shutdown 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 were out-of-control during the reporting period; and	
	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 for periods of startup and shutdown, during the reporting period, the report must contain the information in §63.7550(d); and	
	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)	

§63.7555.. What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

This subpart applies.

(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).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii).

(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.

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

This subpart applies.

(1) Records described in §63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in §63.6(h)(7)(i) and (ii).

(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).

(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 subpart applies.

(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 subpart applies.

(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, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under §241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to §241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in §241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under §241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per §241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under §241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) 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 16 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.

(4) 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 17 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.

(5) 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.

(6) 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.

(7) 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.

(8) 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 18 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.

(9) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(10) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

(11) For each startup period, for units selecting paragraph (2) of the definition of “startup” in §63.7575 you must maintain records of the time that clean fuel combustion begins; the time when you start feeding fuels that are not clean fuels; the time when useful thermal energy is first supplied; and the time when the PM controls are engaged.

(12) If you choose to rely on paragraph (2) of the definition of “startup” in §63.7575, for each startup period, you must maintain records of the hourly steam temperature, hourly steam pressure, hourly steam flow, hourly flue gas temperature, and all hourly average CMS data (*e.g.,* CEMS, PM CPMS, COMS, ESP total secondary electric power input, scrubber pressure drop, scrubber liquid flow rate) collected during each startup period to confirm that the control devices are engaged. In addition, if compliance with the PM emission limit is demonstrated using a PM control device, you must maintain records as specified in paragraphs (d)(12)(i) through (iii) of this section.

(i) For a boiler or process heater with an electrostatic precipitator, record the number of fields in service, as well as each field's secondary voltage and secondary current during each hour of startup.

(ii) For a boiler or process heater with a fabric filter, record the number of compartments in service, as well as the differential pressure across the baghouse during each hour of startup.

(iii) For a boiler or process heater with a wet scrubber needed for filterable PM control, record the scrubber's liquid flow rate and the pressure drop during each hour of startup.

(13) If you choose to use paragraph (2) of the definition of "startup" in §63.7575 and you find that you are unable to safely engage and operate your PM control(s) within 1 hour of first firing of non-clean fuels, you may choose to rely on paragraph (1) of definition of "startup" in §63.7575 or you may submit to the delegated permitting authority a request for a variance with the PM controls requirement, as described below.

(i) The request shall provide evidence of a documented manufacturer-identified safety issue.

(ii) The request shall provide information to document that the PM control device is adequately designed and sized to meet the applicable PM emission limit.

(iii) In addition, the request shall contain documentation that:

(A) The unit is using clean fuels to the maximum extent possible to bring the unit and PM control device up to the temperature necessary to alleviate or prevent the identified safety issues prior to the combustion of primary fuel;

(B) The unit has explicitly followed the manufacturer's procedures to alleviate or prevent the identified safety issue; and

(C) Identifies with specificity the details of the manufacturer's statement of concern.

(iv) You must comply with all other work practice requirements, including but not limited to data collection, recordkeeping, and reporting requirements.

(e) If you elect to average emissions consistent with §63.7522, you must additionally keep a copy of the emission averaging implementation plan required in §63.7522(g), all calculations required under §63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with §63.7541.

This subpart applies, however IFG is not currently electing to average emissions as there is only one boiler.

(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 subpart applies, however IFG is not currently electing to use energy credit.

(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.

This subpart 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.

This subpart does not apply.

§63.7560 .... In what form and how long must I keep my records?

This section §63.7560 and all of the subparts within this section apply.

(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 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.

§63.7565 .... What part 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.

Table 10 to Subpart DDDDD of Part 63—Applicability of General Provisions to Subpart DDDDD

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, except §63.7555(d)(13) specifies the procedure for application and approval of an alternative timeframe with the PM controls requirement in the startup work practice (2).
§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	No. Subpart DDDDD specifies opacity as an operating limit not an emission standard.
§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).

Citation	Subject	Applies to subpart DDDDD
§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.

§63.7570 .... Who implements and enforces this subpart?

Idaho Department of Environmental Quality has been delegated this subpart.

§63.7575 .... What definitions apply to this subpart?

Key definitions are listed below, refer to the regulation for other definitions as they have been omitted here for clarity.

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.

Clean dry biomass means any biomass-based solid fuel that have not been painted, pigment-stained, or pressure treated, does not contain contaminants at concentrations not normally associated with virgin biomass materials and has a moisture content of less than 20 percent and is not a solid waste.

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), process heater(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), process heater(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).

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.

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 over its operating load range. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller or draft controller.

Startup means:

(1) Either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy 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 useful thermal energy from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose, or

(2) The period in which operation of a boiler or process heater is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying useful thermal energy (such as steam or heat) for heating, cooling or process purposes, or producing electricity, or the firing of fuel in a boiler or process heater for any purpose after a shutdown event. Startup ends four hours after when the boiler or process heater supplies useful thermal energy (such as heat or steam) for heating, cooling, or process purposes, or generates electricity, whichever is earlier.

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

§63.6580 .... What is the purpose of this subpart?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§63.6580 .... 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, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

The Grangeville fire-water pump engine is a diesel-fired (compression ignition) RICE. Upon issuance of this permit, IFG's Grangeville facility will be subject to this subpart.

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

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) Existing stationary RICE.

(i) For stationary RICE with a site rating of more than 500 brake horsepower (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 December 19, 2002.

The Grangeville fire-water pump engine is an affected source. It is an existing stationary RICE with a site rating of 218 brake HP and was installed in 1974. This subpart applies.

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

(a) Affected sources. (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, 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, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI 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 stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

IFG Grangeville mill complied with the requirements prior to May 3, 2013.

§63.6602 .... What emission limitations and other requirements 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 and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

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, and replace as necessary; 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]

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.

This subpart applies.

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

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements 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.

This subpart applies.

§63.6612 .... By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing 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 stationary RICE located at an area source of HAP emissions?

If you own or operate an existing 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 stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

This subpart applies.

§63.6615 .... When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

This subpart applies.

§63.6620 .... What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \quad (Eq.\ 1)$$

Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209\ F_d}{F_c} \quad (Eq.\ 2)$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3/J ($dscf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO2} = \frac{5.9}{F_o} \quad (Eq.\ 3)$$

Where:

X_{co2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2—15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO2}}{\%CO_2} \quad (Eq.\ 4)$$

Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2.

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{co2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.,* operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.,* wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

This subpart applies.

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

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O_2 or CO_2 according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2 concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

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

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(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:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP 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;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(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.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(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 business 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 business 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.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 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 Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid 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 business 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 business 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.

This subpart may apply.

§63.6630 .... How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart.

The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

This subpart applies.

§63.6635 .... How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

This subpart applies.

§63.6640 .... How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements 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.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O_2 using one of the O_2 measurement methods specified in Table 4 of this subpart. Measurements to determine O_2 concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O_2 emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that 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 the requirements in Table 8 to this subpart: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. 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 Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed 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 or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(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.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

This subpart applies.

§63.6645 .... What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(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.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) 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 as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

This subpart applies.

§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.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, 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.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance 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 an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration 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, and whether each deviation occurred during a period of malfunction or during another period.

(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 breakdown 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 downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through 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 written report must be submitted to the Administrator at the appropriate address listed in §63.13.

This subpart applies.

§63.6655 .... What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) 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 that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.,* process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(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.

(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;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable 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 engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) 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 that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

This subpart applies.

§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).

This subpart applies.

§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.

This subpart applies.

§63.6670 .... Who implements and enforces this subpart?

Idaho Department of Environmental Quality is delegated this subpart.

Permit Conditions Review

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

Section 1 Permit Scope

Existing Permit Condition 1.1 and 1.2

Describes the scope of the permit and how to identify which permit conditions that have been added or revised due to this permitting action.

Existing Permit Condition 1.3

Has been changed from listing regulated sources to explaining the permit being replaced upon issuance of this permit.

Table 1.1

Table 1.1 has been revised to show the control equipment for BH-1, BH-2, and BH-3 emission units.

Section 2 Facility-Wide Conditions

This section is unchanged, other than updating permit condition 2.6 and 2.10.

Existing Permit Condition 2.6

Was revised to a 60 day timeframe to submit a performance test report from the completion of the performance test, per 58.01.01.157.04.

Initial Permit Condition 2.10

This permit condition establishes the facility wide annual VOC emission limit. The total annual limit is 249 T/yr and is a combination of the kilns, hog fuel wood-fired boiler, pneumatic conveyance for green-wood residue, fire water pump, and waste oil heater operations. This permit condition also lists the specific permit conditions pertaining to the hog wood-fired boiler, kilns, pneumatic conveyance, fire water pump, and waste oil heater operations to demonstrate compliance with the facility annual emission limit .

Section 3 Hog Fuel Boiler

Permit Condition 3.1, 3.2, 3.4, 3.12, 3.13, 3.15, 3.18, 3.19, 3.22, and 3.23 are the only permit conditions in this section that are new and/or revised. All other permit conditions in this section remain unchanged.

Existing Permit Condition 3.1

This permit condition has been revised to state the actual rated heat input capacity of the boiler and to list the boiler so it is consistent with Table 1.1, "Regulated Sources".

Existing Permit Condition 3.2

This permit condition has been revised to reflect the processes associated with the hog fuel boiler.

Initial Permit Condition 3.4

Sets the annual tons per year NOX, and CO emission limit for the hog fuel boiler.

Initial Permit Condition 3.12

This permit condition states the actual boiler steam production tracked as per the Steam and Fuel Monitoring and Recordkeeping Requirements Permit Condition, shall be used in conjunction with the VOC, NO_X, and CO emission factors in units of lb/1,000 lb-steam from the most recent source test to calculate the annual tons per year of CO, NO_X, and VOC emissions from the boiler.

Existing Permit Condition 3.13

This permit condition has been revised to list the current Section 2 permit conditions, 2.6, 2.8 applicable to this PM Compliance Testing Requirements – NSPS, Permit Condition 3.13.

Initial Permit Condition 3.15

Establishes the timeframe in which a source test on the wellons hog fuel boiler shall be completed. This source test will confirm the VOC, CO, and NO_X emission factors listed in permit condition 3.12. The VOC, CO, and NO_X emission factors are directly used to determine the VOC, CO, and NO_X emissions from the wellons boiler. This permit condition also specifies the test to be used, RM25 and the parameters specific to this method. The calculation to obtain the VOC emission factor is also outlined in this permit condition using the molecular weight of VOC and Carbon.

Exiting Permit Condition 3.18

This permit condition was changed from suggesting the facility submit a source test protocol to requiring the facility to submit a source test protocol.

Existing Permit Condition 3.19

Update the 30 day reporting timeframe to 60 days from the conclusion of any compliance test, per IDAPA 58.01.01.157.04

Initial Permit Condition 3.22

The facility is subject to Federal Regulation 40 CFR 63 Subpart DDDDD and explains where to find the federal regulatory analysis.

Initial Permit Condition 3.23

The facility is subject to Federal Regulation 40 CFR 60 Subpart Db and explains where to find the federal regulatory analysis.

Section 4 Dry Kilns

Existing Permit Condition 4.1

Is a revised description of the five dry kilns located at the facility and how heat is provided to them to dry dimension lumber.

Initial Permit Condition 4.2

Established that there are no emission control units for the kilns.

Initial Permit Condition 4.3

States the VOC emissions from the kilns shall be combined with the boiler, pneumatic conveyance of green-wood residue, fire water pump, waste oil heater VOC emissions, to ensure the VOC emissions of all emission units combined, (boiler, kiln, and pneumatic conveyance) shall remain under the facility-wide VOC emission limit of 249 T/yr.

Existing Permit Condition 4.4

This permit condition was changed from a formaldehyde emission limit to the previously establish kiln throughput limit. This permit condition sets the annual lumber that is produced through all dry kilns to ensure the established annual PM_{10} *emission limits modeled in the 2006 permit are not exceeded. This permitting action did not change the throughput, only the wood species specific VOC emission factors to be used to calculate annual VOC emissions have been revised.*

Existing Permit Condition 4.5

This permit condition was changed from the kiln throughout limit to dry kiln production and temperature monitoring. This permit condition explains how to monitor and record the following monthly and annual parameters:

Quantity of each species of all wood processed in all of the kilns, the total sum of all the wood species processed in all of the kilns, and the total quantity of lumber present in the kiln charge. The purpose of these parameters are to ensure the annual throughput limit is not exceeded, and to ensure the specific wood specie emission factor equations are appropriately applied to calculate the VOC emissions from the kilns.

Start and stop date and time. The purpose of this parameter is to ensure the maximum average or instantaneous maximum kiln temperature for that charge was used.

All species of wood contained in the charge. The purpose of this parameter is to ensure if a charge containing mixed wood species is sent through the kilns, the highest emission factor shall be used to calculate the VOC emissions for that charge.

The maximum entering-air temperature. The purpose of this parameter is to ensure the maximum entering air during the wood specie specific charge is being used in the VOC emission factor equation to accurately calculate the VOC emissions generated from that charge.

Existing Permit Condition 4.6

This permit condition was changed from baghouse operating requirements to VOC emission calculations. The baghouse operating requirements can be found in section five. This permit condition explains which emission factor equation to use specific to each individual wood species, how to monitor and record the maximum entering-air temperature of the kilns, and how to calculate the emission factor required to calculate and track VOC emissions on a monthly and annual basis to avoid from triggering PSD. Note: The VOC's from the kilns are to be added to the VOC's from the boiler and pneumatic conveyance operations to ensure the facility maintains less than or equal to 249 tpy in VOC emissions.

Extensive research was completed at the facilities request to consider emission factors different from Oregon DEQ and EPA Region 10. Idaho DEQ is still reviewing emission factors for dimensional lumber drying with kilns, however at this time it has been determined that EPA Region 10, best fit equation submitted to Idaho DEQ in November of 2019 is the best available data to determine emissions from this source.

Initial Permit Condition 4.7

This permit condition explains how to monitor and record the maximum entering-air of the kilns to be used in the

VOC calculations.

Initial Permit Condition 4.8

This permit condition requires the facility to develop an O&M manual for the kilns. The maximum entering air temperature used to calculate the VOC emission factors specific to each wood species is dependent upon the thermocouples within the kilns. This O&M manual is to keep the thermocouples functioning according to the manufacturer specifications, which in turn will provide a more accurate measurement of the maximum entering-air temperature to be used in calculating VOC emissions. The permittee shall also check the calibration semi-annually, and develop a procedure and the frequency to audit the, "Pen Charts" which are used to log the maximum entering-air, to ensure compliance with the VOC emission limits..

Initial Permit Condition 4.9

The facility is subject to Federal Regulation 40 CFR 63 Subpart DDDD and this permit condition explains where to find the federal regulatory analysis.

Initial Permit Condition 5.1

This permit condition was moved from section four of the previous permit to section five of the current permit. This permit condition explains the equipment required to process the logs to prepare them to be dimensionally cut, where the wood products for the Wellons Hog Fuel Boiler comes from, and the required sawmill and planer mill operations to produce a final product.

Initial Permit Condition 5.2

This permit condition describes the control devises for these processes and the processes that do not have control devices.

Initial Permit Condition 5.3

This permit condition states the pneumatic VOC emissions shall be tracked to demonstrate compliance with the facility-wide VOC emission limit listed in permit condition 2.10.

Existing Permit Condition 5.4

This permit condition was moved from section four of the previous permit to section five of the current permit. This permit condition lists the emissions control requirements from PTC P-2008.0204 issued February 17, 2009. This permitting action did not change this permit condition.

Existing Permit Condition 5.5

This permit condition was moved from section four of the previous permit to section five of the current permit. This permit condition lists the baghouse monitoring equipment requirement from PTC P-2008.0204 issued February 17, 2009. This permitting action did not change this permit condition.

Existing Permit Conditions 5.6

This permit condition was moved from section four of the previous permit to section five of the current permit. This permit condition lists the baghouse operations and maintenance manual requirements from PTC P-2008.0204 issued February 17, 2009. This permitting action did not change this permit condition.

Existing Permit Condition 5.7

This permit condition was moved from section four of the previous permit to section five of the current permit. This permit condition lists the baghouse pressure drop monitoring requirement from PTC P-2008.0204 issued February 17, 2009. This permitting action was revised to reflect the facility's current operating procedures.

Initial Permit Condition 5.8

This permit condition lists the specie specific emission factors to be used when calculating the VOC emission from the pneumatic conveyance for the green-wood residue and how to demonstrate compliance with the facility-wide VOC emission limit. The facility is required to submit their assumptions and methodology for these calculations, and when tracking a mixed species the highest emission factor for that load shall be used to calculate the emissions.

Initial Permit Condition 6.1

Explains the process description for the fire water pump and how it is used in the event of a power outage at the facility, and how the waste oil heater is used to heat work spaces.

Initial Permit Condition 6.2

Explains how there are no control devices for this emissions unit.

Initial Permit Condition 6.3

This permit condition states the fire water pump and the waste oil heater VOC emissions shall be tracked to demonstrate compliance with the facility-wide VOC emission limit listed in permit condition 2.10.

Initial Permit Condition 6.4

Describes the federal regulation 40 CFR 63 Subpart ZZZZ the fire water pump and facility are subject to and where the federal regulatory analysis.

Initial Permit Condition 7.1

The duty to comply general compliance provision requires that the permittee comply with all of the permit terms and conditions pursuant to Idaho Code §39-101.

Initial Permit Condition 7.2

The maintenance and operation general compliance provision requires that the permittee maintain and operate all treatment and control facilities at the facility in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 7.3

The obligation to comply general compliance provision specifies that no permit condition is intended to relieve or exempt the permittee from compliance with applicable state and federal requirements, in accordance with IDAPA 58.01.01.212.01.

Initial Permit Condition 7.4

The inspection and entry provision requires that the permittee allow DEQ inspection and entry pursuant to Idaho Code §39-108.

Initial Permit Condition 7.5

The permit expiration construction and operation provision specifies that the permit expires if construction has not begun within two years of permit issuance or if construction has been suspended for a year in accordance with IDAPA 58.01.01.211.02.

Initial Permit Condition 7.6

The notification of construction and operation provision requires that the permittee notify DEQ of the dates of construction and operation, in accordance with IDAPA 58.01.01.211.01 and 211.03.

Initial Permit Condition 7.7

The performance testing notification of intent provision requires that the permittee notify DEQ at least 15 days prior to any performance test to provide DEQ the option to have an observer present, in accordance with IDAPA 58.01.01.157.03.

Initial Permit Condition 7.8

The performance test protocol provision requires that any performance testing be conducted in accordance with the procedures of IDAPA 58.01.01.157, and encourages the permittee to submit a protocol to DEQ for approval prior to testing.

Initial Permit Condition 7.9

The performance test report provision requires that the permittee report any performance test results to DEQ within 60 days of completion, in accordance with IDAPA 58.01.01.157.04-05.

Initial Permit Condition 7.10

The monitoring and recordkeeping provision requires that the permittee maintain sufficient records to ensure compliance with permit conditions, in accordance with IDAPA 58.01.01.211.

Initial Permit Condition 7.11

The excess emissions provision requires that the permittee follow the procedures required for excess emissions events, in accordance with IDAPA 58.01.01.130-136.

Initial Permit Condition 7.12

The certification provision requires that a responsible official certify all documents submitted to DEQ, in accordance with IDAPA 58.01.01.123.

Initial Permit Condition 7.13

The false statement provision requires that no person make false statements, representations, or certifications, in accordance with IDAPA 58.01.01.125.

Initial Permit Condition 7.14

The tampering provision requires that no person render inaccurate any required monitoring device or method, in accordance with IDAPA 58.01.01.126.

Initial Permit Condition 7.15

The transferability provision specifies that this permit to construct is transferable, in accordance with the procedures of IDAPA 58.01.01.209.06.

Initial Permit Condition 7.16

The severability provision specifies that permit conditions are severable, in accordance with IDAPA 58.01.01.211.

PUBLIC REVIEW

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.01.c. During this time, comments were submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

APPENDIX A – EMISSIONS INVENTORIES

IDAHO FOREST GROUP - GRANGEVILLE, IDAHO

Idaho State ID Number 049-00003. Current Tier I Permit T1-2012.0060, under renewal. Current PTC P-2008.0204, incorporated in Tier I.

Emission Inventory using Updated Emission Factors from November 25, 2019

	PM10 (ton/yr)	PM2.5 (ton/yr)	SO_2 (ton/yr)	NOx (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPs (ton/yr)
Point Sources							
WELLONS FUEL CELL BOILER WITH ESP	28.91	28.91	12.70	249.0	25.40	102	21.2
LUMBER DRY KILNS	4.75	4.13	---	---	192.89	---	29.4
SAWDUST CYCLONE BAGHOUSE, BH-1	0.110	0.074	---	---	---	---	---
SHAVINGS CYCLONE BAGHOUSE, BH-2	0.500	0.335	---	---	---	---	---
SHAVINGS BIN VENT CYCLONE BAGHOUSE, BH-3	0.500	0.335	---	---	---	---	---
SAWMILL SAWDUST CYCLONE, CY-1	5.500	2.750	---	---	---	---	---
PLANER CHIPPING ROOM CYCLONE, CY-2	0.575	0.288	---	---	---	---	---
PLANER CHIP CYCLONE, CY-3	0.575	0.288	---	---	---	---	---
FILING ROOM CYCLONE, CY-4	4.0E-04	2.0E-04	---	---	---	---	---
RETAIL SHAVINGS CYCLONE, CY-5	0.500	0.250	---	---	---	---	---
WASTE OIL HEATER	0.042	0.031	0.0482	0.0288	0.0018	0.0038	1.28E-02
FIRE WATER PUMP	2.29E-04	2.27E-04	4.46E-05	5.32E-02	4.41E-04	1.65E-03	1.63E-02
Point Source Total Emissions	**41.96**	**37.38**	**12.75**	**249.04**	**218.29**	**101.62**	**50.57**
Process Fugitive Sources							
END FLARE REDUCER, PF-1	0.032	0.006	---	---	---	---	---
DEBARKER, PF-2	0.099	0.018	---	---	---	---	---
MERCHANDIZER, PF-3	0.150	0.027	---	---	---	---	---
BARK HOG, PF-4	0.0083	0.0015	---	---	---	---	---
DISC SCREEN, 60% OF FUEL, PF-5	0.188	0.033	---	---	---	---	---
SAWDUST BIN TRUCK LOADOUT, PF-6	0.0019	0.0003	---	---	---	---	---
CHIP TRUCK BIN TOP VENT, PF-7	0.0038	0.0005	---	---	---	---	---
CHIP BIN TRUCK LOADOUT, PF-8	0.0075	0.0011	---	---	---	---	---
PLANER SHAVINGS BIN TRUCK LOADOUT, PF-9	0.0018	0.0003	---	---	---	---	---
PLANER CHIPS LOADOUT, PF-10	0.0004	0.0001	---	---	---	---	---
SAWMILL SAWING INDOORS, PF-11	0.066	0.0115					
PNEUMATIC CONVEYING OF WOOD RESIDUALS	---	---	---	---	11.39	---	---
Process Fugitive Total Emissions	**0.5574**	**0.0980**	**0.0000**	**0.0000**	**11.3885**	**0.0000**	**0.0000**
Fugitive Sources							
CONVEYORS	0.0012	0.0002	---	---	---	---	---
TRANSFERS	0.0124	0.0019	---	---	---	---	---
STORAGE SOURCE EMISSIONS	0.1741	0.0971	---	---	---	---	---
FUGITIVE DUST - UNPAVED ROADS	4.5017	0.4502	---	---	---	---	---
FUGITIVE DUST - PAVED ROADS	0.3488	0.0856	---	---	---	---	---
Fugitive Total Emissions	**5.04**	**0.63**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Plantwide Total	**47.56**	**38.12**	**12.75**	**249.04**	**229.68**	**101.62**	**50.57**

IDAHO FOREST GROUP - GRANGEVILLE, IDAHO

Idaho State ID Number 049-00003. Current Tier I Permit T1-2012.0060, under renewal. Current PTC P-2008.0204, incorporated in Tier I.

Emission Inventory/Calculations

Proposed PTE with Wellons Boiler

	PM10 (lb/hr)	PM2.5 (lb/hr)	SO_2 (lb/hr)	NOx (lb/hr)	VOCs (lb/hr)	CO (lb/hr)
Point Sources						
WELLONS FUEL CELL BOILER WITH ESP	6.60	6.60	2.90	56.8	5.80	23.2
LUMBER DRY KILNS	2.75	2.75	---	---	44.04	---
SAWDUST CYCLONE BAGHOUSE, BH-1	0.07	0.05	---	---	---	---
SHAVINGS CYCLONE BAGHOUSE, BH-2	0.33	0.22	---	---	---	---
SHAVINGS BIN VENT CYCLONE BAGHOUSE, BH-3	0.33	0.22	---	---	---	---
SAWMILL SAWDUST CYCLONE, CY-1	3.67	1.83	---	---	---	---
PLANER CHIPPING ROOM CYCLONE, CY-2	0.38	0.19	---	---	---	---
PLANER CHIP CYCLONE, CY-3	0.38	0.19	---	---	---	---
FILING ROOM CYCLONE, CY-4	1.3E-04	6.4E-05	---	---	---	---
RETAIL SHAVINGS CYCLONE, CY-5	0.16	0.08	---	---	---	---
WASTE OIL HEATER	0.08	0.06	0.00	0.06	0.10	0.01
FIRE WATER PUMP	4.58E-03	4.54E-03	8.92E-04	1.06	8.82E-03	3.31E-02
Point Source Total Emissions	**14.77**	**12.21**	**2.90**	**57.96**	**49.94**	**23.24**
Process Fugitive Sources						
END FLARE REDUCER, PF-1	2.11E-02	3.74E-03	---	---	---	---
DEBARKER, PF-2	6.60E-02	1.17E-02	---	---	---	---
MERCHANDIZER, PF-3	1.00E-01	1.77E-02	---	---	---	---
BARK HOG, PF-4	5.50E-03	9.74E-04	---	---	---	---
DISC SCREEN, 60% OF FUEL, PF-5	1.25E-01	2.21E-02	---	---	---	---
SAWDUST BIN TRUCK LOADOUT, PF-6	1.28E-03	1.83E-04	---	---	---	---
CHIP TRUCK BIN TOP VENT, PF-7	2.51E-03	3.58E-04	---	---	---	---
CHIP BIN TRUCK LOADOUT, PF-8	5.02E-03	7.17E-04	---	---	---	---
PLANER SHAVINGS BIN TRUCK LOADOUT, PF-9	1.17E-03	1.67E-04	---	---	---	---
PLANER CHIPS LOADOUT, PF-10	2.68E-04	3.83E-05	---	---	---	---
SAWMILL SAWING INDOORS, PF-11	4.38E-02	7.66E-03				
PNEUMATIC CONVEYING OF WOOD RESIDUALS	---	---	---	---	2.60	---
Process Fugitive Total Emissions	**0.3716**	**0.0653**	**0.0000**	**0.0000**	**2.6001**	**0.0000**
Fugitive Sources						
CONVEYORS	Hourly emissions not used for modeling.					
STORAGE SOURCE EMISSIONS	Hourly emissions not used for modeling.					
FUGITIVE DUST - UNPAVED ROADS	Hourly emissions not used for modeling.					
FUGITIVE DUST - PAVED ROADS	Hourly emissions not used for modeling.					
Fugitive Totals	**NA**	**NA**	**---**	**---**	**---**	**---**
Plantwide Total	**15.14**	**12.27**	**2.90**	**57.96**	**52.54**	**23.24**

IDAHO FOREST GROUP, GRANGEVILLE
Production Information for Emissions Calculations

Lumber Production

Process	Annual Production Rate		Daily Production Rate		Comments:
Sawmill	250,000	mbf/year	2,000	mbf/day	Maximum sawmill physical capacity
Dry Kilns	250,000	mbf/year	2,000	mbf/day	Maximum kiln physical capacity
Planer	250,000	mbf/year	2,000	mbf/day	Maximum planer physical capacity
Logs Used	900,000	tons/yr, green	7,200	tons/day, green	Tons estimated based on 3.6 tons logs/mbf.
Sawmill Hours	7,488	hours/year	24	hrs/day	6 days/week, 52 weeks
Planer Hours	7,488	hours/year	24	hrs/day	6 days/week, 52 weeks
Kiln Hours	8,760	hours/year	24	hrs/day	365 days/year

Steam Plant Information

				Comments:
Boiler Steam Capacity	80,000	pounds of steam per hour (pph)		As described in Tier I permit Section 4.
Boiler Heat Input	116	MMBtu/hr, design heat input		As described in Tier I permit Section 4.
Boiler Hours	8,760	hours/year, potential		
Boiler Annual Steam	700,800	thousand pounds/yr, steam production potential		
Boiler Annual Heat Input	1,016,160	MMBtu/yr, heat input potential		

Residuals Production, Based on IFG Records

	BDT/yr	BDT/day	Estimation Factor		
Sawmill Chips	107,500	860	0.43	BDT/mbf sawmill	Based on Grangeville records
Sawdust	55,000	440	0.22	BDT/mbf sawmill	Based on Grangeville records
Hog Bark	75,000	600	0.30	BDT/mbf sawmill	Based on Grangeville records
Planer Chips	5,750	46	0.023	BDT/mbf planer	Based on Grangeville records
Shavings	25,000	200	0.10	BDT/mbf planer	Based on Grangeville records

	Moisture Content	Green Wt. ton/year	ton/day
Sawmill Chips	50%	215,000	1,720
Sawdust	50%	110,000	880
Hog Bark	50%	150,000	1,200
Planer Chips	15%	6,765	54
Shavings	15%	29,412	235
	Moisture Content	**Dry Wt. BDT/yr**	**BDT/day**
Logs	50%	450,000	3,600

WELLONS FUEL CELL BOILER WITH ESP

Boiler Production	8,760	Hours/Year	Max Potential Hours
	80,000	lb steam/hour	Peak 1-hour steam rate
	116	MMBtu/hr, design	Design heat input
	700,800	klb steam/yr	PTE annual steam production
	1,016,160	MMBtu/yr	PTE annual heat input

CRITERIA POLLUTANT EMISSIONS

PM/PM10/PM2.5 are considered equal for a well-controlled combustion source.

Filterable PM (controlled), MACT Limit			
Emission Factor:	0.02	lb/MMBtu	Boiler MACT Limit for Fuel Cell Boilers
Emissions:	10.16	tons/year	Filterable PM only.
	2.32	lbs/hr	
PM10/PM2.5 (controlled), Permit Limit			
Emissions:	28.9	tons/year	T1-2012.0060 permit limit for PM10, no change.
	6.6	lbs/hr	T1-2012.0060 permit limit for PM10, no change.
Sulfur Dioxide:			
Emission Factor:	0.025	lb/MMBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	12.70	tons/year	
	2.90	lbs/hr	
Nitrogen Oxides (NOx)			
Emission Factor:	0.49	lb/MMBtu	(AP-42 TABLE 1.6-2, Rev 9/03, ef for dry wood)
Emissions:	248.96	tons/year	In response to EPA suggestion in Aug. 9, 2019 letter
	56.84	lbs/hr	to Idaho DEQ.
Carbon Monoxide (CO)			
Emission Factor:	0.20	lb/MMBtu	Wellons specified emission rate.
Emissions:	101.62	tons/year	See emissions report.
	23.20	lbs/hr	
Volatile Organic Compounds (VOC)			
Emission Factor:	0.05	lb/MMBtu	Wellons boiler emission guarantee
Emissions:	25.40	tons/year	Tracking value: 0.072 lb/klb steam
	5.80	lbs/hr	

MACT Emission Limits, based on January 31, 2015 version of Boiler MACT. Effective 3-years after permit is changed to HAPS major

Particulate Matter, filterable			
Emission Factor:	0.020	lb/MMBtu heat input	Table 2 to Subpart DDDDD of Part 63
Emissions:	10.16	tons/year	Boiler type 12 - fuel cell boilers/biomass
	2.32	lbs/hr	
Carbon Monoxide (CO)			
MACT Emission Limit:	1100	ppm @ 3% oxygen	Table 2 to Subpart DDDDD of Part 63
Flue Gas flowrate at 0% oxygen:	1,113,600	dscf/hr, flue gas @ 0% oxygen	Based on F-Factor for wood bark
Flue Gas flowrate at 3% oxygen:	1,300,237	dscf/hr, flue gas @ 3% oxygen	Adjusted to 3% oxygen
Gas emitted in lbmol:	3,427	lbmol/hr, flue gas @ 3% oxygen	379.4 dscf/lbmol At 60^{o}F and 1 atm.
CO emitted in lbmol:	3.77	lbmol/hr CO	1500 ppm CO
Molecular Weight CO:	28.01	lb/lbmol	M.W. = 28.01 lb/lbmol
Allowable CO Emissions:	105.6	lb/hr CO	MACT allowable, higher than proposed limit
	462	tpy CO	MACT allowable, higher than proposed limit

Biomass Combustion on Boiler Greenhouse Gas (GHG) Emissions

Boiler Heat Input	1,016,160	MMBtu/year	
Based on 40CFR98 - Mandatory Greenhouse Gas Reporting, current as of August 30, 2018			
40CFR98.2(b)(2) says to exclude CO2 emissions from biomass combustion but include CH4 and N2O from biomass combustion in GHG calculation.			
Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)			
Emission Factor (SI Units):	93.8	kg/MMBtu	Table C-1 to Subpart C of Part 98.
Emission Factor (English Units):	206.36	lb/MMBtu	
Potential Emissions:	104,847	tpy CO2	Short tons
Methane			
Emission Factor (SI Units):	7.20E-03	kg/MMBtu	Table C-2 to Subpart C of Part 98
Emission Factor (English Units):	1.58E-02	lb/MMBtu	
Potential Emissions:	8.05	tpy CH4	Short tons per year
	7.32	MT per year	Metric tons per year
Nitrous Oxide			
Emission Factor:	3.60E-03	lb/MMBtu	Table C-2 to Subpart C of Part 98
Emissions:	1.83	tpy N2O	Short tons
	3.66	MT per year	Metric Tons
Total	**104,857**	**tpy GHG**	**Short tons per year**

Calculated Carbon Dioxide Equivalent (CO2e)

Compound	GWP	Calculated GHG		
Carbon Dioxide	NA	0		CO2 excluded as per 40CFR98.2(b)(2)
Methane	25	183	MT CO2e	Table A-1 , Subpart A, Part 98, GWP updated 1/1/14
Nitrous Oxide	298	1,090	MT CO2e	Table A-1 , Subpart A, Part 98, GWP updated 1/1/14
Total GHG		**1,273**	**MT CO2e**	

WELLONS HOG FUEL BOILER

HAZARDOUS AIR POLLUTANTS (HAPS) Wellons Boiler

Operating Parameters:		
Actual Hours of Operation	hours/yr	8,760
Max Heat Input	MMBtu / hr	116.0
Annual Boiler Heat Input	MMBtu / yr	1,016,160

Emission Factors:

AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03) *Boiler MACT Limit	CAS Number	HAP?	TAP Class (A/B)(1)	Emission Factor (lb/MMBtu)	Annual Emissions (tons/yr)	HAP Emissions (tons/yr)		
Acenaphthene		N	NA	9.1E-07	4.62E-04			
Acenaphthylene		N	NA	5.0E-06	2.54E-03			
Acetaldehyde	75070	Y	A	8.3E-04	4.22E-01	4.22E-01		4.97170640
Acetone		N	B	1.9E-04	9.65E-02			
Acetophenone	98862	Y	NA	3.2E-09	1.63E-06	1.63E-06		
Acrolein	107028	Y	B	4.0E-03	2.03E+00	2.03E+00		2.147320
Anthracene		N	NA	3.0E-06	1.52E-03			
Benzaldehyde		N	NA	8.5E-07	4.32E-04			
Benzene	71432	Y	A	4.2E-03	2.13E+00	2.13E+00		
Benzoic acid		N	NA	4.7E-08	2.39E-05			
bis(2-ethylhexyl)phthalate (DEHP)	117817	Y	A	4.7E-08	2.39E-05	2.39E-05		
Bromomethane (methyl bromide)	74839	Y	B	1.5E-05	7.62E-03	7.62E-03		
2-Butanone (MEK) - Removed from HAPS	78933	N	B	5.4E-06	2.74E-03			
Carbazole		N	NA	1.8E-06	9.15E-04			
Carbon tetrachloride	56235	Y	A	4.5E-05	2.29E-02	2.29E-02		
Chlorine	7782505	Y	B	7.9E-04	4.01E-01	4.01E-01		
Chlorobenzene	108907	Y	B	3.3E-05	1.68E-02	1.68E-02		
Chloroform	67663	Y	A	2.8E-05	1.42E-02	1.42E-02		
Chloromethane (Methyl Chloride)	74873	Y	B	2.3E-05	1.17E-02	1.17E-02		
2-Chloronaphthalene		N	NA	2.4E-09	1.22E-06			
2-Chlorophenol		N	NA	2.4E-08	1.22E-05			
Crotonaldehyde	123739	N	B	9.9E-06	5.03E-03			
Decachlorobiphenyl		N	NA	2.7E-10	1.37E-07			
1,2-Dibromoethene		N	NA	5.5E-05	2.79E-02			
Dichlorobiphenyl		N	NA	7.4E-10	3.76E-07			
1,2-Dichloroethane (Ethylene Dichloride)	107062	Y	A	2.9E-05	1.47E-02	1.47E-02		
Dichloromethane (Methylene chloride)	75092	Y	A	2.9E-04	1.47E-01	1.47E-01		
1,2-Dichloropropane (Propylene dichloride)	78875	Y	B	3.3E-05	1.68E-02	1.68E-02		
2,4 Dinitrophenol	51285	Y	NA	1.8E-07	9.15E-05	9.15E-05		
Dioxins and Furans, Not TCDD		N	NA	1.7E-06	8.49E-04			
Heptachlor dibenzo-p-dioxins		N	NA	*2.0E-09*				
Heptachlor dibenzo-p-furans		N	NA	*2.4E-10*				
Hexachlorodibenzo-p-dioxins		N	NA	*1.6E-06*				
Hexachlorodibenzo-p-furans		N	NA	*2.8E-10*				
Octachlorodibenzo-p-dioxins		N	NA	*6.6E-08*				
Octachlorodibenzo-p-furans		N	NA	*8.8E-11*				
Pentachlorodibenzo-p-dioxins		N	NA	*1.5E-09*				
Pentachlorodibenzo-p-furans		N	NA	*4.2E-10*				
Dioxins and Furans, TCDD		Y	A	1.3E-09	6.70E-07			
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	Y	A	*8.6E-12*				
Tetrachlorodibenzo-p-dioxins		Y	A	*4.7E-10*				
2,3,7,8-Tetrachlorodibenzo-p-furans		Y	A	*9.0E-11*				
Tetrachlorodibenzo-p-furans		Y	A	*7.5E-10*				
Ethylbenzene	100414	Y	B	3.1E-05	1.58E-02	1.58E-02		
Formaldehyde	50000	Y	A	4.4E-03	2.24E+00	2.24E+00		2.9259645
Heptachlorobiphenyl		N	NA	6.6E-11	3.35E-08			
Hexachlorobiphenyl		N	NA	5.5E-10	2.79E-07			
Hexanal		N	NA	7.0E-06	3.56E-03			
Hydrogen chloride (Hydrochloric Acid)*	7647010	Y	B	2.2E-02	1.12E+01	1.12E+01	Boiler MACT Limit	
Isobutyraldehyde		N	NA	1.2E-05	6.10E-03		was 9.6 tpy	
Methane		N	NA	2.1E-02	1.07E+01			
2-Methylnaphthalene		N	NA	1.6E-07	8.13E-05			
Monochlorobiphenyl		N	NA	2.2E-10	1.12E-07			
Naphthalene	91203	Y	B	9.7E-05	4.93E-02	4.93E-02		
2-Nitrophenol		N	NA	2.4E-07	1.22E-04			
4-Nitrophenol	100027	Y	NA	1.1E-07	5.59E-05	5.59E-05		
Pentachloropbiphenyl		N	NA	1.2E-09	6.10E-07			
Pentachlorophenol	87865	Y	B	5.1E-08	2.59E-05	2.59E-05		
Perylene		N	NA	5.2E-10	2.64E-07			
Phenanthrene		N	NA	7.0E-06	3.56E-03			
Phenol	108952	Y	B	5.1E-05	2.59E-02	2.59E-02		
Propanal = Propionaldehyde	123386	Y	B	6.1E-05	3.10E-02	3.10E-02		
Polyaromatic Hydrocarbons (except 7-PAH group)		N	A	5.3E-06	2.67E-03			
Benzo(e)pyrene				*2.6E-09*				
Benzo(g,h,i)perylene				*9.3E-08*				
Benzo(j,k)fluoranthene				*1.6E-07*				
Fluoranthene				*1.6E-06*				
Fluorene				*3.4E-06*				
Polycyclic Organic Matter (POM) = 7-PAH Group		Y	A	2.9E-06	1.49E-03	1.49E-03		
Benzo(a)anthracene		Y	A	*6.5E-08*				
Benzo(a)pyrene		Y	A	*2.6E-06*	1.32E-03			
Benzo(b)fluoranthene		Y	A	*1.0E-07*				
Benzo(k)fluoranthene		Y	A	*3.6E-08*				
Indeno(1,2,3,cd)pyrene		Y	A	*8.7E-08*				
Chrysene		Y	A	*3.8E-08*				
Dibenzo(a,h)anthracene		Y	A	*9.1E-09*				
Pyrene		N	NA	3.7E-06	1.88E-03			
Styrene	100425	Y	B	1.9E-03	9.65E-01	9.65E-01		
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	Y	A	8.6E-12	4.37E-09	4.37E-09		
Tetrachlorobiphenyl		N	NA	2.5E-09	1.27E-06			
Tetrachloroethene		N	NA	3.8E-05	1.93E-02			
o-Tolualdehyde		N	NA	7.2E-06	3.66E-03			
p-Tolualdehyde		N	NA	1.1E-05	5.59E-03			
Toluene	108883	Y	B	9.2E-04	4.67E-01	4.67E-01		
Trichlorobiphenyl		N	NA	2.6E-09	1.32E-06			
1,1,1-Trichloroethane (Methyl Chloroform)	71556	Y	B	3.1E-05	1.58E-02	1.58E-02		
Trichloroethene (Trichloroethylene)	79016	Y	A	3.0E-05	1.52E-02	1.52E-02		
Trichlorofluoromethane	75694	Y	NA	4.1E-05	2.08E-02	2.08E-02		
2,4,6-Trichlorophenol	88062	Y	A	2.2E-08	1.12E-05	1.12E-05		
Vinyl Chloride	75014	Y	A	1.8E-05	9.15E-03	9.15E-03		
o-Xylene	95476	Y	B	2.5E-05	1.27E-02	1.27E-02		
Antimony	7440-36-0	Y	B	7.9E-06	4.01E-03	4.01E-03		
Arsenic	7440-38-2	Y	A	2.2E-05	1.12E-02	1.12E-02		
Barium	7440-39-3	N	B	1.7E-04	8.64E-02			
Beryilium	7440-41-7	Y	A	1.1E-06	5.59E-04	5.59E-04		
Cadmium	7440-43-9	Y	A	4.1E-06	2.08E-03	2.08E-03		
Chromium, total	16065-83-1	Y	B	2.1E-05	1.07E-02	1.07E-02		
Chromium, hexavalent	18540-29-9	Y	A	3.5E-06	1.78E-03	1.78E-03		
Cobalt	7440-48-4	Y	B	6.5E-06	3.30E-03	3.30E-03		
Copper	7440-50-8	N	B	4.9E-05	2.49E-02			
Iron		N	NA	9.9E-04	5.03E-01			
Lead	7439-92-1	Y	NA	4.8E-05	2.44E-02	2.44E-02		
Manganese	7439-96-5	Y	B	1.6E-03	8.13E-01	8.13E-01		
Mercury (removed from TAPs)*	7439-97-6	Y	NA	5.7E-06	2.90E-03	2.90E-03	Boiler MACT Limit	
Molybdenum	7439-98-7	N	B	2.1E-06	1.07E-03			
Nickel	7440-02-0	Y	A	3.3E-05	1.68E-02	1.68E-02		
Phosphorus	7223-14-0	Y	B	2.7E-05	1.37E-02	1.37E-02		
Potassium		N	NA	3.9E-02	1.98E+01			
Selenium	7782-49-2	Y	B	2.8E-06	1.42E-03	1.42E-03		
Silver	7440-22-4	N	B	1.7E-03	8.64E-01			
Sodium		N	NA	3.6E-04	1.83E-01			
Strontium		N	NA	1.0E-05	5.08E-03			
Tin	7440-31-5	N	B	2.3E-05	1.17E-02			
Titanium		N	NA	2.0E-05	1.02E-02			
Vanadium	1314-62-1	N	B	9.8E-07	4.98E-04			
Yttrium		N	NA	3.0E-07	1.52E-04			
Zinc		N	NA	4.2E-04	2.13E-01			
					TOTAL HAPS	**21.19**		
(1) TAP Class A is regulated under IDAPA 58.01.01.586 and TAP Class B is regulated under IDAPA 58.01.01.585.								

LUMBER DRY KILNS

Using EPA November 2019 Emission Factors

250,000 mbf/yr, lumber dried
2,000 mbf/day, physical max potential

CRITERIA POLLUTANTS

PM10 :

Emission Factor:	0.038	lbs/mbf	Willamette Ind. 1998 Source Tests
Emissions:	4.75	tons/year	Douglas fir and Hemlock
	76.00	lbs/day	Factor negotiated between IFG and DEQ
	3.17	lb/hr	

PM2.5 :

Emission Factor:	0.033	lbs/mbf	Willamette Ind. 1998 Source Tests
Emissions:	4.13	tons/year	Douglas fir and Hemlock
	66.00	lbs/day	Factor negotiated between IFG and DEQ
	2.75	lb/hr	

VOC:

Emission Factor:	1.54	lbs/mbf	Species-dependent emission factor
Emissions:	192.89	tons/year	VOC Emissions based on values below
	44.04	lbs/hr	

Based on species mix shown as an example.

Wood Species, representative:	% of Total	Drying Temp (°F)	VOC (lb/Mbf)	Weighted (lb/Mbf)	PCWR Factor (lb/MBF)	PCWR Emissions (tpy)
White Fir	30.0%	245	0.98032	0.294	0.0811	3.04
Western Hemlock	0.0%	245	0.51208	0.000	0.0811	0.00
Western Red Cedar	0.0%	180	0.44927	0.000	0.0811	0.00
Douglas Fir	60.0%	230	1.5867	0.952	0.0811	6.08
Engelmann Spruce	0.0%	215	0.1769	0.000	0.0811	0.00
Larch	0.0%	230	1.5867	0.000	0.0811	0.00
Lodgepole Pine	0.0%	245	1.135	0.000	0.1721	0.00
Ponderosa Pine	10.0%	205	2.970	0.297	0.1721	2.15
Western White Pine	0.0%	205	2.970	0.000	0.1721	0.00
Douglas fir and larch (DFL)	0.0%	230	1.587	0.000	0.0811	0.00
Hemlock and fir (HF)	0.0%	245	0.980	0.000	0.0811	0.00
Spruce and lodgepole (ESLP)	0.0%	245	1.135	0.000	0.0811	0.00
Other Species not listed	0.0%	205	2.970	0.000	0.1721	0.00
Total	100.0%			**1.54**		**11.28**

HAZARDOUS AIR POLLUTANTS

EMISSION FACTORS:	Emission factors discussed in Emissions Report					
Pollutant	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propionaldehyde	Acrolein
White Fir	0.4738	0.4057	0.0116	0.0550	*0.0004*	*0.0012*
Western Hemlock	0.2855	0.2126	0.0036	0.0677	0.0004	0.0012
Western Red Cedar	0.1739	0.1034	0.0012	0.0677	0.0004	0.0012
Douglas Fir	0.1322	0.1013	0.0026	0.0275	0.0003	0.0005
Engelmann Spruce	0.0772	0.0539	0.0025	0.0201	0.0002	0.0005
Larch	0.1322	0.1013	0.0026	0.0275	0.0003	0.0005
Lodgepole Pine	0.0956	0.0550	0.0030	*0.0340*	*0.0010*	*0.0026*
Ponderosa Pine	0.1334	0.0911	0.0047	0.0340	0.0010	0.0026
Western White Pine	0.1334	0.0911	0.0047	0.0340	0.0010	0.0026
Douglas fir and larch (DFL)	0.1322	0.1013	0.0026	0.0275	0.0003	0.0005
Hemlock and fir (HF)	0.4738	0.4057	0.0116	0.0677	0.0004	0.0012
Spruce and lodgepole (ESLP)	0.0956	0.0550	0.0030	0.0340	0.0010	0.0026
Other Species not listed	0.1334	0.4057	0.0116	0.0677	0.0010	0.0026

EMISSIONS

Species	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propionaldehyde	Acrolein
White Fir	35,536	30,424	867	4,125	30	90
Western Hemlock	0	0	0	0	0	0
Western Red Cedar	0	0	0	0	0	0
Douglas Fir	19,836	15,195	396	4,125	45	75
Engelmann Spruce	0	0	0	0	0	0
Larch	0	0	0	0	0	0
Lodgepole Pine	0	0	0	0	0	0
Ponderosa Pine	3,334	2,277	118	850	25	65
Western White Pine	0	0	0	0	0	0
Douglas fir and larch (DFL)	0	0	0	0	0	0
Hemlock and fir (HF)	0	0	0	0	0	0
Spruce and lodgepole (ESLP)	0	0	0	0	0	0
Other Species not listed	0	0	0	0	0	0
TOTAL, lb/yr	58,706	47,895	1,381	9,100	100	230
TOTAL, ton/yr	29.35	23.95	0.69	4.55	0.05	0.12

Italicised values are assumed because EPA reference had no data.

CYCLONE AND BAGHOUSE PTE EMISSIONS

Source	PM10 ef (lb/BDT)	reference	PM2.5 ef (lb/BDT)	reference			
SAWDUST CYCLONE BAGHOUSE, BH-1	0.04	AQ-EF02, CY w/BH, dry mat'l	0.027	67% of PM10(1)	Gets up to 10% of sawdust	Formerly CY11BH	
SHAVINGS CYCLONE BAGHOUSE, BH-2	0.04	AQ-EF02, CY w/BH, dry mat'l	0.027	67% of PM10(1)		Formerly CY72BH	
SHAVINGS BIN VENT CYCLONE BAGHOUSE, BH-3	0.04	AQ-EF02, CY w/BH, dry mat'l	0.027	67% of PM10(1)		Formerly CY73	
SAWMILL SAWDUST CYCLONE, CY-1	0.2	AQ-EF02, CY green or large mat'l	0.1	50% of PM10(1)	Gets up to 100% of sawdust	Formerly CY12	
PLANER CHIPPING ROOM CYCLONE, CY-2	0.2	AQ-EF02, CY green or large mat'l	0.1	50% of PM10(1)		Formerly CY75	Emissons Control
PLANER CHIP CYCLONE, CY-3	0.2	AQ-EF02, CY green or large mat'l	0.1	50% of PM10(1)		Formerly CY71	Process Equp
SHAVINGS BIN VENT CYCLONE	0.2	Bin vent, not bulk loaded.	0.1	50% of PM10(1)		Formerly CY73	Emissons Control, will be replaced with BH
FILING ROOM CYCLONE, CY-4	0.2	AQ-EF02, CY green or large mat'l	0.1	50% of PM10(1)	Collects Saw filings.	Formerly CY41	Process Equp
RETAIL SHAVINGS CYCLONE, CY-5	0.2	AQ-EF02, CY green or large mat'l	0.1	50% of PM10(1)		Formerly CY74	Not used now, could be used again

(1) DEQ determined that baghouse PM2.5 should be calculated as 67% of PM10 and cyclone PM2.5 should be calculated as 50% of PM10.

Source	Basis	Production Units	Current PTE PM10 (ton/yr)	Daily PM10 (lb/hr)	PM2.5 (ton/yr)	PM2.5 (lb/hr)	
SAWDUST CYCLONE BAGHOUSE, BH-1	5,500	BDT/yr	0.1100		0.0737		
	44	BDT/day		0.0733		0.0491	
SHAVINGS CYCLONE BAGHOUSE, BH-2	25,000	BDT/yr	0.5000		0.3350		
	200	BDT/day		0.3333		0.2233	
SHAVINGS BIN VENT CYCLONE BAGHOUSE, BH-3	25,000	BDT/yr	0.5000		0.3350		
	200	BDT/day		0.3333		0.2233	
SAWMILL SAWDUST CYCLONE, CY-1	55,000	BDT/yr	5.5000		2.7500		
	440	BDT/day		3.6667		1.8333	
PLANER CHIPPING ROOM CYCLONE, CY-2	5,750	BDT/yr	0.5750		0.2875		
	46	BDT/day		0.38333		0.19167	
PLANER CHIP CYCLONE, CY-3	5,750	BDT/yr	0.5750		0.2875		
	46	BDT/day		0.3833		0.1917	
SHAVINGS BIN VENT CYCLONE	Controlled by newly added baghouse.						
FILING ROOM CYCLONE, CY-4	4	BDT/yr	0.0004		0.0002		Throughput Estimated
	0.015	BDT/day		0.0001		0.0001	
RETAIL SHAVINGS CYCLONE, CY-5	5,000	BDT/yr	0.5000		0.2500		Could be restarted if market available.
	19	BDT/day		0.1603		0.0801	

Conversion of minutes to hours	60	min/hr
Conversion of grains to lbs	7000	gr/lb

MILL FUGITIVE SOURCES

Production Information Used in Fugitive Emission Calculations

Logs Used	900,000	tons/yr, green	7,200	tons/day, green
Logs to Reducer	28,800	tons/yr, green	230	tons/day, green
Hogged Bark	150,000	tons/yr, green	1,200	tons/day, green
	75,000	BDT/yr	600	BDT/day
Logs without Bark	750,000	tons/yr, green	6,000	tons/day, green
Sawdust	55,000	BDT/yr	440	BDT/day
Sawmill Chips	215,000	BDT/yr	1720	BDT/day
Shavings	25,000	BDT/yr	200	BDT/day
Planer Chips	5,750	BDT/yr	46	BDT/day

Emission Factors						PM10	PM10	PM2.5	PM2.5	
Fugitive Emissions Source	**PM10 ef**	**PM2.5 ef**	**Units**	**Control Eff.**	**Emission Factor Reference**	**tpy**	**lb/hr (daily)**	**tpy**	**lb/hr (daily)**	
END FLARE REDUCER, PF-1	0.011	0.001947	lb/ton logs, green	80%	AIRS 3-07-008-01, NCASI for PM2.5%. 80% control for partial enclosure.	3.17E-02	2.11E-02	5.61E-03	3.74E-03	Formerly P12
DEBARKER, PF-2	0.011	0.001947	lb/ton logs, green	98%	AIRS 3-07-008-01, NCASI for PM2.5%. 98% control for partial enclosure.	9.90E-02	6.60E-02	1.75E-02	1.17E-02	Formerly P13
MERCHANDIZER, PF-3	0.2	0.0354	lb/ton logs, green	98%	AIRS 3-07-008-01, NCASI for PM2.5%. 98% control for full enclosure.	1.50E-01	1.00E-01	2.66E-02	1.77E-02	Formerly P14
BARK HOG, PF-4	0.011	0.001947	lb/BDT bark	98%	AIRS 3-07-008-01, NCASI for PM2.5%. 98% control for enclosure.	8.25E-03	5.50E-03	1.46E-03	9.74E-04	Formerly P15
DISC SCREEN, 60% OF FUEL, PF-5	0.05	0.00885	lb/BDT bark	90%	General Material Handling, NCASI for PM2.5%. 90% control for partial enclosure.	1.88E-01	1.25E-01	3.32E-02	2.21E-02	Formerly P22
SAWDUST BIN TRUCK LOADOUT, PF-6	0.00035	0.00005	lb/BDT sawdust	80%	FARR drop factor "wet", 80% control for side panels	1.93E-03	1.28E-03	2.75E-04	1.83E-04	
CHIP TRUCK BIN TOP VENT, PF-7	0.00035	0.00005	lb/BDT chips	90%	FARR drop factor "wet", 90% control enclosure	3.76E-03	2.51E-03	5.38E-04	3.58E-04	
CHIP BIN TRUCK LOADOUT, PF-8	0.00035	0.00005	lb/BDT chips	80%	FARR drop factor "wet", 80% control for side panels	7.53E-03	5.02E-03	1.08E-03	7.17E-04	
PLANER SHAVINGS BIN TRUCK LOADOUT, PF-9	0.0007	0.0001	lb/BDT shavings	80%	FARR drop factor "dry", 80% control for sides panels	1.75E-03	1.17E-03	2.50E-04	1.67E-04	
PLANER CHIPS LOADOUT, PF-10	0.0007	0.0001	lb/BDT planer chips	80%	FARR drop factor "dry", 80% control for sides panels	4.03E-04	2.68E-04	5.75E-05	3.83E-05	
SAWMILL SAWING INDOORS, PF-11	0.175	0.031	lb/BDT peeled logs	99.9%	FARR PM10 sawing factor, NCASI PM2.5%, 99.9% control indoors (FARR uses 100%),	6.56E-02	4.38E-02	1.15E-02	7.66E-03	

NCASI Special Report No. 15-01, Table 6.1 Average Total Potential Filterable PM10 and PM2.5 for Chips and Bark

Fresh Wood Chips	17.5%	PM2.5 portion of PM10 emissions
Fresh Bark	17.7%	PM2.5 portion of PM10 emissions
Hogged Bark	15.4%	PM2.5 portion of PM10 emissions

P16-P17 quantified elsewhere. P18-21, 26 are kilns. P23 and p25 not found. P24 was with Rosebud process.

PNEUMATIC CONVEYING OF WOOD RESIDUALS

Production Information Used in Fugitive Emission Calculations

Logs Used	900,000	tons/yr, green	7,200	tons/day, green
Logs to Reducer	28,800	tons/yr, green	230	tons/day, green
Hogged Bark	150,000	tons/yr, green	1,200	tons/day, green
	75,000	BDT/yr	600	BDT/day
Logs without Bark	750,000	tons/yr, green	6,000	tons/day, green
Sawdust	55,000	BDT/yr	440	BDT/day
Sawmill Chips	215,000	tons/yr, green	1720	tons/day, green
Shavings	25,000	BDT/yr	200	BDT/day
Planer Chips	5,750	BDT/yr	46	BDT/day

	Emission Factors from EPA Potlatch Permit					VOC as Propane	Methanol
Fugitive Emissions Source	**VOC as Propane**	**Methanol**	**Units**	**% of Kiln**	**Emission Factor Reference**	**tpy**	**tpy**
Non-pine Sawdust Pneumatic	0.2386	0.0016	lb/odt(1)	89%	EPA's Potlatch Permit	5.84	3.92E-02
Non-pine Planer Shavings Pneumatic	0.2692	0.0016	lb/odt(1)	89%	EPA's Potlatch Permit	2.99	1.78E-02
Non-pine Planer Chip Pneumatic	0.0734	0.0016	lb/odt(1)	89%	EPA's Potlatch Permit	0.19	4.09E-03
Non-pine Green Chip - Not Pneumatic	0.0734	0.0016	lb/odt(1)	89%	EPA's Potlatch Permit		
Pine Sawdust Pneumatic	0.5017	0.0016	lb/odt(1)	11%	EPA's Potlatch Permit	1.52	4.84E-03
Pine Planer Shavings Pneumatic	0.5017	0.0016	lb/odt(1)	11%	EPA's Potlatch Permit	0.69	2.20E-03
Pine Planer Chip Pneumatic	0.5017	0.0016	lb/odt(1)	11%	EPA's Potlatch Permit	0.16	5.06E-04
Pine Green Chip - Not Pneumatic	0.5017	0.0016	lb/odt(1)	11%	EPA's Potlatch Permit		
						11.39	0.07

(1) ODT not defined by EPA. Assume it equals BDT.

FUGITIVE DUST - UNPAVED ROADS
Calculations based on AP-42 Section 13.2.2, rev. 12/06

Source	Class	Number Trips Per Year	Distance per Trip (miles)	VMT per Year	Avg. Vehicle Weight W	Weighted Vehicle Weight
Log Trucks	Unpaved, Loaded	45,000	0.8	36,000	36	9.82
	Unpaved, Empty	45,000	0.8	36,000	16	4.36
Log Yard	Unpaved, Loaded	300,000	0.1	30,000	4	0.91
Loaders	Unpaved, Empty	300,000	0.1	30,000	1	0.23
			TOTAL	**132,000**		**15**

E = [k(s/12)^a*(w/3)^b]

		PM	PM10	PM2.5		
k =		4.9	1.5	0.15		
Composite s=		0.7	0.7	0.7	Log trucks drive ~0.7 miles on gravel road	
W =		15.32	15.32	15.32	(s=0.10%) and ~0.1 miles on logyard (s=4.8%).	
a=		0.7	0.9	0.9	Table 13.2.2-1, B13s02.2.	
b=		0.45	0.45	0.45		
Uncontrolled	E=	1.38 lb/VMT	0.24 lb/VMT	0.02 lb/VMT		
Uncontrolled	Eext=	0.79	0.14	0.01	P=	156
		lb/VMT	lb/VMT	lb/VMT	N=	365
Controlled	E=	0.39	0.07	0.01	Watering provides 50% control	
		lb/VMT	lb/VMT	lb/VMT		

Total PM Emissions:	**26.05**	**tpy**
Total PM10 Emissions:	**4.50**	**tpy**
Total PM2.5 Emissions:	**0.45**	**tpy**

FUGITIVE DUST - PAVED ROADS
Calculations based on AP-42 Section 13.2.1.3, rev. 1/11

Source	Class	Number Trips Per Year	Distance per Trip (miles)	VMT per Year	Avg. Vehicle Weight W	Particle Size Multiplier k	Weighted Vehicle Weight
Fork Lifts	Paved, Loaded	13,889	0.10	1,389	4.2	0.082	0.11
	Paved, Empty	13,889	0.10	1,389	1	0.082	0.03
LumberTrucks	Paved, Loaded	13,889	0.70	9,722	33	0.082	6.08
	Paved, Empty	13,889	0.70	9,722	13	0.082	2.40
dust, Shavings and Chip Tr	Paved, Loaded	18,059	0.50	9,029	33	0.082	5.65
	Paved, Empty	18,059	0.50	9,029	13	0.082	2.22
Misc. Vehicles incl employee	Paved	62,400	0.20	12,480	3	0.082	0.71
				52,761			17.20

E=k(sL)^0.91(W)^1.02 *[1-1.2*P/N]

	PM	PM10	PM2.5	P=	120
k =	0.011	0	0.00	N=	365
sL=	1.1	1	1.10		
W =	17.2	17.2	17.2		
E=	0.1	0.0	0.0		
	lb/VMT	lb/VMT	lb/VMT		
% control from washing/sw	50%	50%	50%		
Total PM Emissions:	**1.74**	**tpy**			
Total PM10 Emissions:	**0.35**	**tpy**			
Total PM2.5 Emissions:	**0.09**	**tpy**			

Mobile Sources Fugitive Dust - SUMMARY
Based on Production, for Emissions Estimation Only

Truck Schedule

Log Truck:	900,000	tons logs/yr
	20	tons/truck
	45,000	log trucks/yr
Log Yard Loaders	900,000	tons logs/yr
	3	tons/load
	300,000	loads/yr
Sawdust/S Trucks	361,176	tons /yr
	20	tons/load
	18,059	loads/yr
Lumber Tr	250,000	mbdft/yr
	18,000	bdft/truck
	13,889	lumber trucks/yr
Fork Lifts,	250,000	mbdft/yr
	3	tons/load
	83,333	fork lift trips/yr

TRANSFER AND CONVEYOR CALCULATIONS

Transfer and conveyor points are not shown on process flow diagram.

Total Emissions	PM (tons/year)	PM10 (tons/year)	PM25 (tons/year)
CONVEYORS	0.0034	0.0012	0.0002
TRANSFERS	0.0355	0.0124	0.0019
Total	**0.0389**	**0.0136**	**0.0021**

Emission Factor Calculations

* Use AP 42 13.2.4 Aggregate Handling

E=k(.0032)*((u/5)**1.3)/((M/2)**1.4)

average wind speed = 9 mph

moisture content for green wood and bark is estimated at 47%

moisture content for lumber after dry kiln estimated at 19%

particulate matter multiplier

Species	k
PM	1
PM10	0.35
PM2.5	0.053

at 47% moisture content	PM EF =	8.27E-05 lbs/ton	PM-10 EF =	2.89E-05 lbs/ton	PM-2.5 EF =	4.38E-06 lbs/ton
at 25% moisture content (Debr Area soils)	PM EF =	2.00E-04 lbs/ton	PM-10 EF =	7.00E-05 lbs/ton	PM-2.5 EF =	1.06E-05 lbs/ton
at 22% moisture content	PM EF =	2.39E-04 lbs/ton	PM-10 EF =	8.38E-05 lbs/ton	PM-2.5 EF =	1.27E-05 lbs/ton
at 19% moisture content	PM EF =	2.94E-04 lbs/ton	PM-10 EF =	1.03E-04 lbs/ton	PM-2.5 EF =	1.56E-05 lbs/ton
at 3% moisture content	PM EF =	3.89E-03 lbs/ton	PM-10 EF =	1.36E-03 lbs/ton	PM-2.5 EF =	2.06E-04 lbs/ton

Conveyors

Name	Code	Conveyors included	# drops	Moisture Content %	PM Em. Factor (lb/ton)	PM-10 Em. Factor (lb/ton)	PM-2.5 Em. Factor (lb/ton)	Annual Throughput (BDT)	PM Emissions (tons/yr)	PM-10 Emissions (tons/yr)	PM-2.5 Emissions (tons/yr)	Moisture Content	Material Transferred	Emission Control Methodology	Emission Control %	Oper hours
Incoming log conveyors	Cinf	11, 12, 13, 14, 15, 17, 18 or 19, 20 or 21, 22	9	47%	0.0001	0.000029	0.000004	450,000	0.003	0.00117	0.00018	47%	whole logs	building or surrounding equipment	98%	4,000
Refuse line under incoming log, canter lines	Cref	45	1	47%	0.0001	0.000083	0.000004	1,000	0.000	0.00002	0.00000	47%	pieces off whole logs	building or surrounding equipment	50%	4,000

Most facility conveyors have sides at least 2' high, many considerably higher, that are at least twice as high as the material being carried, eliminating the chance for wind erosion emissions. All drops are addressed below as transfer points.

The few listed below carry whole logs, with few fines, in areas partially or nearly enclosed (Ca), or two initial debris lines below initial log infeed lines (c41 or Cb).

Control efficiencies are %s based upon protection of material on conveyor from open release or wind. Because EFs are based upon an aggregate mix of medium and fine size materials, emission control % were increased for transfers of very large materials (like whole logs)

Transfers

All transfers are to or from conveyors except the truck bin drops and the Rosebud bldg load in / out

All conveyors carrying anything other than whole logs (except for 2 in the sawmill infeed line) have at least 23" high sides for emission controls

Control efficiencies are %s based upon enclosures and protection from open release or wind. Because EFs are based upon an aggregate mix of medium and fine size materials, emission control % were increased for transfers of very large materials (like whole logs)

Throughput volumes are from material balance or very conservatively estimated for lower volume side lines

Name	Modeling Code	Transfer Point #s included	# drops	Material Transferred	Moisture Content %	PM Em. Factor (lb/ton)	PM-10 Em. Factor (lb/ton)	PM-2.5 Em. Factor (lb/ton)	Emission Control Methodology	Emission Control %	Oper hours	Throughput (BDT)	PM Emissions (tons/yr)	PM-10 Emissions (tons/yr)	PM-2.5 Emissions (tons/yr)
LOG INFEED LINE		*this line moves whole logs only from the log yard to the sawmill. Control efficiency accounts for low amt of fines and silt coming off whole logs*													
Log Infeed system outside	Tinf	11 or 12,13,14,16,17, 19 0r 21, 20 or 22, 23 or 24, 25	9	whole logs	47%	0.0001	0.0000	0.0000	building and surrounding equipment	98%	4,000	450,000	0.00	0.00117	0.00018
drop to reject log bunk (est.)	Tinf	15, 18, 26	2	whole logs	47%	0.0001	0.0000	0.0000	building and surrounding equipment	98%	2,000	40	0.00	0.00000	0.00000
Log infeed line (incoming log wood waste) (est)	Trefin	41,42	2	pieces off whole logs	47%	0.0001	0.0000	0.0000	surrounding equipment	50%	4,000	40	0.00	0.00000	0.00000
Main refuge volume (saw waste)	Trefline	43,46, 48	3	bark, sawdust, woodwaste	47%	0.0001	0.0000	0.0000	2' high conv sides, taller sheeted sides	50%	4,000	55,000	0.00	0.00119	0.00018
Canter,A21 DLI Line (mill waste wood) (est.)	Trefin	44, 45	2	sawdust, chips, wood waste	47%	0.0001	0.0000	0.0000	2' high conv sides, taller sheeted sides	50%	4,000	1400	0.00	0.00002	0.00000
Yard waste (log yard wood waste manually) (est)	Trefyard	47	1	wood waste	47%	0.0001	0.0000	0.0000	none	0%	4,000	2800	0.00	0.00004	0.00001
Hog reject line (est)	Trefrej	49, 50	2	wood waste, metal contam.	47%	0.0001	0.0000	0.0000	none	0%	4,000	70	0.00	0.00000	0.00000
Sawmill cyclone to dust bin (est)	Trefrej	62	1	sawdust, fines	47%	0.0001	0.0000	0.0000	booted (enclosed) drop	90%	4,000	20	0.00	0.00000	0.00000
SAWMILL PRODUCT OUTFLOW		These lines take sawdust to truck bins and chips to chip bins. Emission controls applied for chips only due to high sided conveyors and controlled drops to trucks with walled sides													
Dust coll cycl			inside building, emissions quantified elsewhere as part of material balance												
Dust coll cycl to sawdust trucks. Process Fugitive	Toutsawd	30, 31	2	sawdust	47%										
Sawmill sawdust - Cycl	Trefrej	32	1	sawdust	47%	0.0001	0.0000	0.0000	(enclosed) drop	90%	4,000	0	0.00	0.00	0.00
Chip system to chip trucks. Process Fugitive	Toutchip	33,34,35	3	chips	47%										
FUEL TO BOILER (from Disc Screen)		*this line transfers bark to a bin for shipping, takes fine fuel to the boiler on conveyors with 2' high side walls, and hogs (chops up) larger wood waste before sending it to the boiler in totally enclosed conveyors with covered drops*													
Fines to Hog Outfeed (est.)	Tboihog	65, 54	2	fines	47%	0.0001	0.0000	0.0000	tall sheeted sides onto walled conv	75%	4,000	3000	0.00	0.00002	0.00000
Hogged Wood to Hog Outfeed (est.)	Tboihog	53, 57, 66	3	chopped wood waste	47%	0.0001	0.0000	0.0000	tall sheeted sides onto walled conv	75%	4,000	42000	0.00	0.00046	0.00007
Hog Outfeed to Boiler	Tboifeed	56, 58 or 59	2	fines, chopped wood waste	47%	0.0001	0.0000	0.0000	sheeted sides, drop into conv inside pipe	90%	4,000	75,000	0.00	0.00022	0.00003
Enclosed lines to fuel silo		60, 61							**fully enclosed**	**100%**					
Filing rm dust, defect sawfeed (est.)	Tboihog	62, 63	2	fines, sawdust	47%	0.0001	0.0000	0.0000	sheeted drop	80%	4,000	48	0.00	0.00000	0.00000
Ash into ash bins	Tboifeed	67	1	ash	3%	0.0039	0.0014	0.0002	mostly enclosed trasfer area into ash bin	90%	4,000	75,000	0.01	0.00511	0.00077
Deco bark to bark trucks (est.)	Tboibrk	64, 51, 52	3	bark	22%	0.0002	0.0001	0.0000	semi covered drops to bin, 2 full sheeted sides tight enclosure elsewhere at bin	75%	4,000	14000	0.00	0.00044	0.00007
PLANER OUTFLOW		*shavings, chips, and fines from planed, dried lumber, all to be processed as saleable material to trucks. Most of the material is pneumatically transferred in enclosed tubes, drops to trucks walled on 2 sides, tightly fit on the other 2. 50% control efficiency conservatively applied*													
Chips to Chip trucks. Process Fugitive.	Tplnchp	71, 72	2	chips	19%										
Retail shavings operation	Trosebud	75	1	planer shavings	19%	0.0003	0.0001	0.0000	building around shavings pile	75%	500	0	0.00	0.00	0.00
Fines to fines truck. Process fugitive	Tplnfin	73, 74	2	fines	19%										
WOOD DEBRIS MANAGEMENT		management of wood waste													
Load yard waste materials to go to Debris Management Area	STDMA	91	1	soils	25%	0.0002	0.0001	0.0000	none	0%	4,000	14000	0.00	0.00049	0.00007
Ash removal (ash bins to truck for transport to WDMA) (est.)	Tboifeed	69	1	ash	3%	0.0039	0.0014	0.0002	none	0%	1,000	2400	0.00	0.00164	0.00025
Drop ash in Debris Management Area (est.)	STDMA	92	1	ash	3%	0.0039	0.0014	0.0002	none	0%	2,000	2400	0.00	0.00164	0.00025
Drop waste materials in Debris Management Area (est.)	STDMA	93	1	soils	25%	0.0002	0.0001	0.0000	none	0%	4,000	14000	0.00	0.00049	0.00007
											TRANSFER TOTALS		**0.04**	**0.01**	**0.00**

STORAGE SOURCE EMISSIONS

all emissions from all storage bins, all truck bins and fuel silos are quantified under transfers, which include transfers into and out of all those storage units.
The storage units themselves are covered and sealed. Therefore, no new storage bins (except the ash bin) future will have emissions in this category

Reference: yard waste storage Use AP 42 13.2.4 Aggregate Handling and Storage Piles

E=k(.0032)*((u/5)**1.3)/((M/2)**1.4)

particulate matter multiplier (k) = .35 for pm 10 and (k) = 0.053 for PM2.5

average wind speed = 9 mph

at 47% moisture content	PM EF =	0.0001	lbs/ton	PM-10 EF =	0.00003	lbs/ton	PM-2.5 EF =	0.000004 lbs/ton
at 25% moisture content	PM EF =	0.0002	lbs/ton	PM-10 EF =	0.0001	lbs/ton	PM-2.5 EF =	0.000011 lbs/ton

STORAGE BINS AND STORAGE Name	ST #	Modeling Code	Thrput (tons/yr)	PM EF (lb/ton)	PM 10 EF (lb/ton)	PM 2.5 EF (lb/ton)	% control	Operat. Hrs/yr	PM (tons/yr)	PM10 (tons/yr)	PM2.5 (tons/yr)
Enclosed ash hopper (est.)	S 44	STash	2,400	1	0.58	0.32344045	75%	2,000	0.300	0.174	0.097
Yard waste pile (est.)	S 76	Trefyard	2,800	0.0001	0.000029	0.000004	90%	4,000	0.0000116	0.0000041	0.0000006
Debris Management Area (est)	S 91	STDMA	20,000	0.0001	0.00003	0.000004	50%	4,000	0.0004	0.0001	0.00002
								Total	**0.3**	**0.2**	**0.1**

VOC emissions from the two diesel tanks (calculated using EPA TANKS 4.09)

diesel tank	**V1**	combined breathing and working loss	3.47	lbs/yr
diesel tank	**V2**	combined breathing and working loss	5.10	lbs/yr
Oil drums	**V3**	*air emssions negligible*		
		TOTAL VOC emissions from diesel tanks	8.57	lbs/yr
			0.004	**tons/yr**

STORAGE BINS WITH NO EMISSIONS

Fuel Silo #1	S 1	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Fuel Silo #2	S 2	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Sawmill Sawdust Truck Bin	S 11	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Sawmill Chip Truck Bin	S 12	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Bark Truck Bin	S 43	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Green Lumer Storage Area	S 71	**Negligible emissions from cut dimensional lumber**, transfer and transporting vehicle emissions accounted for elsewhere
Dry Lumer Storage Area	S 72	**Negligible emissions from dried dimensional lumber**, transfer and transporting vehicle emissions accounted for elsewhere
Fines Truck Bin	S 73	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Planer Chip Truck Bin	S 74	**Enclosed container with no emissions**, transfer emissions in and out accounted for under Transfers
Finished Lumber Storage Area	S 75	**Negligible emissions from dried dimensional lumber**, transfer and transporting vehicle emissions accounted for elsewhere
Log Storage Area	S 77	**Negligible emissions from watered log piles**, transfer and transporting vehicle emissions and yard waste pile accounted for elsewhere

Ref for Ash Storage emissions: IDEQ EF's for the Wood Industry, sawdust pile
Ref: IDEQ EF's for the Wood Industry

IFG Grangeville - Atomizing Waste Oil Heater
WASTE OIL HEATER
PTE Emission and Calculations Supporting Level II Permitting Exemption for Waste Oil Burner
IDAPA 58.01.01.220, 58.01.01.222(h)(i thru v), and 58.01.01.223

Required info for calculations:		A= % ash by weight in fuel	0.46	% Ash by weight for diesel oil
		L = % Lead by weight in fuel	0.0057	% Lead by weight for diesel oil
		S=% Sulfur by weight in fuel	0.25	% Sulfur by weight for diesel oil
		% chlorine by weight	0.1	% chlorine by weight
gal fuel/hr	PTE hrs/yr	PTE gal fuel/yr		
3.6	8760	31,536		
	Operational hr/yr	Operational gal fuel/yr		
	1000	3,600		

Tons/yr emissions from Waste Oil Heater

Criteria Pollutant Emission factors AP-42 section 1-11, in lbs/1000 gallons

AP-42 table 1.11-1 (lbs/1000 gal)				AP-42 table 1.11-2			AP-42 Table 1.11-3		
PM	**PM-10**	**PM-25**	**Lead**	**NOx**	**SOx**	**CO**	**TOC**	**HCl**	
64A	51A		55L		107S			66S	
29.44	23.46	17.18	0.3135	16	26.75	2.1	1	6.60	
	0.084	0.062	0.001	0.058	0.096	0.008	0.004	Lb/hr	
0.05	0.042	0.031	0.001	0.029	0.048	0.004	0.002	**Operational PTE**	
0.46	0.37	0.27	0.00	0.25	0.42	0.03	0.02	**Exemption PTE**	
25	15	10	0.6	40	40	100	100	Significant Emissions Level	
yes	yes	yes	yes	yes	yes	yes	yes	Exempt?	

Vermont Used Oil Analysis and Waste oil Furnace Emission Study, revised 1996
showed mean ash % by wt of 0.54% for gas engines, 0.46% for diesel engines, and 0.55% for No. 2 fuel
mean lead content was 47.23 ppm for gas engines, 57.00 for diesel engines, and ,10.00 ppm for No. 2 fuel

HAP Emission factors AP-42 section 1-11, in lbs/1000 gallons for all listed EPA regulated HAPs

	HAP	EF (lb/1000 gal)	Emissions (ton/year)	Emissions (lb/hr)	EL (lb/hr)	
AP-42 Table 1.11-3	Hydrogen Chloride	6.60	1.19E-02	2.38E-02	0.05	under
AP-42 Table 1.11-4	Antimony	4.50E-03	8.10E-06	1.62E-05	0.033	under
	Arsenic	0.06	1.08E-04	2.16E-04	1.50E-06	over
	Beryllium	0.0018	3.24E-06	6.48E-06	2.80E-05	under
	Cadmium	0.012	2.16E-05	4.32E-05	3.70E-06	over
	Chromium	0.18	3.24E-04	6.48E-04	0.033	under
	Cobalt	0.0052	9.36E-06	1.87E-05	0.333	under
	Manganese	0.05	9.00E-05	1.80E-04	0.333	under
	Nickel	0.16	2.88E-04	5.76E-04	2.70E-05	over
	Phosphorus	3.60E-02	6.48E-05	1.30E-04	0.007	under
AP-42 Table 1.11-5	Phenol	2.80E-05	5.04E-08	1.01E-07	1.27	under
	Napthalene	9.20E-05	1.66E-07	3.31E-07	3.33	under
		TOTAL	1.28E-02			

Toxic Impact Analysis
AERSCREEN Modeling Results, based on an emission rate of 1 g/s

1-hr peak	61.03	(ug/m3)/(g/s)
3-hr peak	42.72	(ug/m3)/(g/s)
8-hr peak	42.72	(ug/m3)/(g/s)
24-hr peak	24.41	(ug/m3)/(g/s)
Annual peak	4.88	(ug/m3)/(g/s)

Compound	Total Annual Emissions (lb/yr)	AACC Cancer Annual (ug/m3)	Emission Rate (g/s)	Modeled Annual Impact ug/m3	Passes Screening
Arsenic	2.16E-01	2.3E-04	2.72E-05	1.33E-04	yes
Cadmium	4.32E-02	5.6E-04	5.45E-06	2.66E-05	yes
Nickel	5.76E-01	4.2E-03	7.26E-05	3.55E-04	yes

FIRE WATER PUMP

Subpart ZZZZ apply.

218 horsepower — 100 hours of operation

Emission factors from Manufacturer's specifications — as per Subpart ZZZZ

Criteria Pollutants

Pollutant	EF	Units	Convert EF to lbs/hp/hr	lb/hr	tons/yr @ 100 hrs/yr
CO	0.15	g/hp-hr	3.31E-04	3.31E-02	1.65E-03
PM	0.021	g/hp-hr	4.63E-05	4.63E-03	2.31E-04
PM10	0.021	g/hp-hr	4.58E-05	4.58E-03	2.29E-04
PM2.5	0.021	g/hp-hr	4.54E-05	4.54E-03	2.27E-04
VOC *	0.04	g/hp-hr	8.82E-05	8.82E-03	4.41E-04
NOx	4.83	g/hp-hr	1.06E-02	1.06E+00	5.32E-02
SOx	0.004	lb/hp-hr	8.92E-06	8.92E-04	4.46E-05

SOx emissions from AP-42 Section 3, Table 3.4-1 given as 0.00809 * S1, where S1 is the sulfur % in fuel.

VOC emission rate listed is for "HC" on manufacturer's specs

Hazardous Air Pollutants

Pollutant	EF	Units	lb/yr	tons/yr	EPA regulated HAPs tons/yr
Benzene	7.76E-04	lbs/hp-hr	17	**0.008**	**0.008**
Toluene	2.81E-04	lbs/hp-hr	6	**0.003**	**0.003**
o-Xylene	1.93E-04	lbs/hp-hr	4	**0.002**	**0.002**
Propylene	2.79E-03	lbs/hp-hr	61	**0.030**	
Formaldehyde	7.89E-05	lbs/hp-hr	2	**0.001**	**0.001**
Acetaldehyde	2.52E-05	lbs/hp-hr	1	**0.000**	**0.0003**
Acrolein	7.88E-06	lbs/hp-hr	0	**0.000**	**0.0001**
Napthalene	1.30E-04	lbs/hp-hr	3	**0.001**	**0.001**
Acenaphthylene	9.23E-06	lbs/hp-hr	0	**0.000**	
Acenaphthene	4.68E-06	lbs/hp-hr	0	**0.000**	
Fluorene	1.28E-05	lbs/hp-hr	0	**0.000**	
Phenanthrene	4.08E-05	lbs/hp-hr	1	**0.000**	
Anthracene	1.23E-06	lbs/hp-hr	0	**0.000**	
Fluoranthene	4.03E-06	lbs/hp-hr	0	**0.000**	
Pyrene	3.71E-06	lbs/hp-hr	0	**0.000**	
Benz(a)anthracene	6.22E-07	lbs/hp-hr	0	**0.000**	
Chrysene	1.53E-06	lbs/hp-hr	0	**0.000**	
Benzo(b)fluoranthene	1.11E-06	lbs/hp-hr	0	**0.000**	
Benzo(k)fluoranthene	2.18E-07	lbs/hp-hr	0	**0.000**	
Benzo(a)pyrene	2.57E-07	lbs/hp-hr	0	**0.000**	
Indeno(1,2,3-cd)pyren	4.14E-07	lbs/hp-hr	0	**0.000**	
Dibenz(a,h)anthracene	3.46E-07	lbs/hp-hr	0	**0.000**	
Benzo(g,h,l)perylene	5.56E-07	lbs/hp-hr	0	**0.000**	
Total PAH	2.12E-04	lbs/hp-hr	5	**0.002**	
				Total EPA Regulated HAPS	**0.016**

Emission factors from AP-42 Section 3.4, Table 3.4-3 and 4

APPENDIX B – FACILITY DRAFT COMMENTS

The following comments were received from the facility on May 10, 2019:

Facility Comment: Page 3, Permit Condition 1.1.
The permit description is incomplete and has unnecessary detail. IFG requests that the language be clarified as follows:

'This is a PTC revision to update lumber dry kiln VOC and HAP emission factors, remove HAP emission limits, add VOC-tracking requirements and add a baghouse to control emissions from the planer shavings truck bin cyclone.'

DEQ Response: Page 3, Permit Condition 1.1 has been updated to reflect the facility's request.

Facility Comment: Page 4, Table 1.1.

Line 4 should say "BH-1 – Sawmill sawdust cyclone with baghouse". A baghouse PM_{10} control efficiency of 99.9% has been added by DEQ. IFG prefers not to list this control efficiency because the control efficiency depends on the inlet loading, so it is not useful information.

Line 5 should say "BH-2 – Planer shavings cyclone with baghouse". Same efficiency comment as above. Note spelling of planer.

Line 6 should say "BH-3 – Planer shavings cyclone with baghouse". Same efficiency comment as above.

Line 8 should say "CY-2 – Planer chipping room cyclone".

DEQ Response: Page 4, Table 1.1 has been updated to reflect the facility's request.

Facility Comment: Page 7, Permit Condition 2.6.

The current permit requires that performance test reports be submitted within 30 days. This requirement is based on IDAPA 58.01.01.157.04, which was revised in 2015 to allow 60 days for report submittal. IFG requests that this permit condition be changed to be consistent with the revised regulation and Permit Condition 7.9.

DEQ Response: Page 7, Permit Condition 2.6 has been updated to reflect the facility's request.

Facility Comment: Page 8, Permit Condition 2.10.

This permit condition was met after the original permit was issued in 2009. IFG requests that DEQ reword or remove this condition to avoid future confusion.

DEQ Response: Page 8, Permit Condition 2.10 has been removed to reflect the facility's request.

Facility Comment: Page 9, Permit Condition 3.7. Daily Steam Production Limit

DEQ has altered this permit condition and has failed to indicate that this is now a DRAFT condition. The permit condition is the Daily Steam Production Limit but DEQ has added an hourly steam production limit in this draft permit. The hourly capacity of the boiler is limited by design, so an hourly limit is not needed or useful. Monitoring for the Daily Steam Production Limit is required in Permit Condition 3.10.1 and relies on the steam totalizer. Monitoring for an hourly limit using the steam totalizer is not possible. IFG requests that DEQ return the Daily Steam Production Limit permit condition to the original language.

DEQ Response: Page 9, Permit Condition 3.7 has been changed back to the original language to reflect the facility's request.

Facility Comment: Page 10, Permit Condition 3.8.

IFG requests that 3.8.1 refer to the O&M Manual requirement in Permit Condition 3.14 as it does on the current permit (not the general reference included in the draft permit). In 3.8.2, ES needs to be corrected to ESP.

DEQ Response: Page 10, Permit Condition 3.8 has been updated to reflect the facility's request.

Facility Comment: Page 11, Permit Condition 3.12.

Reference to Permit Condition 2.14 should be changed to Permit Condition 2.9.

Reference to Permit Condition 3.5.2 is not needed. Permit Condition 3.5.2 was previously the Idaho opacity rule, which is now in Permit Condition 2.3.1. Visible emissions testing for Permit Condition 2.3.1 is listed in the first bullet item.

Reference in first bullet item should be changed to Permit Condition 2.3.1 (not 2.3).

Fourth bullet item should be changed back to Btus (not Btu's).

DEQ Response: Page 11, Permit Condition 3.12 has been updated to reflect the facility's request.

Facility Comment: Page 12, Permit Condition 3.16.

IFG has the same request as listed under Permit Condition 2.6. (IDAPA 58.01.01.157.04)

DEQ Response: Page 12, Permit Condition 3.16 has been updated to reflect the facility's request.

Facility Comment: Page 12, Permit Condition 3.19. NSPS Subpart A.

This permit condition is redundant to Permit Condition 3.17.

DEQ Response: Page 12, Permit Condition 3.19. NSPS Subpart A has been removed to reflect the facility's request.

Facility Comment: Page 13, Permit Condition 3.20. NSPS Subpart Db.

This permit condition is not required because the requirements of NSPS Subpart Db are incorporated in existing permit conditions.

DEQ Response: Page 13, Permit Condition 3.20. NSPS Subpart Db has been removed to reflect the facility's request.

Facility Comment: Page 13, Permit Condition 3.21. NESHAPS Subpart DDDDD.

The reference should be to Federal Regulatory Analysis (not Federal Regulation Analysis).

DEQ Response: Page 13, Permit Condition 3.21. NESHAPS Subpart DDDDD has been updated to reflect the facility's request.

Facility Comment: Page 14, Permit Condition 4.3.

Reference to Table 4.2 (not 3.2). There is no footnote b

DEQ Response: Page 14, Permit Condition 4.3 has been updated to reflect the facility's request.

Facility Comment: Page 14, Permit Condition 4.5.

This condition was previously Permit Condition 4.11. The content of the condition unchanged.

DEQ Response: Noted.

Facility Comment: Page 14, Permit Condition 4.6.

The SOB, page 121 contains the following description of the reason DEQ chose to put these particular dry kiln VOC emission factors into the permit. It states:

This permit condition explains which emission factor to use specific to each individual wood species and how to track VOC emissions on a monthly and annual basis to avoid from triggering PSD. Note: The VOC's from the kilns are to be added to the VOC's from the boiler to ensure the facility maintains less than 250.00 T/year in VOC emissions.

Extensive research was completed at the facilities request to consider emission factors different from Oregon DEQ and EPA Region 10. Idaho DEQ is still reviewing emission factors for dimensional lumber drying with kilns, however at this time it has been determined that EPA Region 10, December 2015 published lumber drying kiln emission factors is the best available data to determine emissions from this source.

Although the date in the SOB says the factors are from December 2015, IFG recognizes these to be the EPA Region 10 factors from December 2012. IFG has done extensive research using original dry kiln test information to determine the best dry kiln VOC emission factors. IFG has previously shared this research with DEQ and is including it with this response to make it part of the official PTC application record. The full IFG submittal regarding proposed dry kiln emission factors is included as Attachment A to this response.

The EPA emission factor compilation groups the emission factor test results based on temperature less than or equal to 200 degrees Fahrenheit ($\leq$ 200 ^{o}F) and greater than 200 degrees Fahrenheit (> 200 ^{o}F). IFG has reviewed all information supporting the EPA 2012 memo and has found no basis for the EPA assumption that high-temperature drying begins at 200^{o}F. This appears to be an arbitrary decision by EPA, which is not supported by wood-drying science.

IFG's research into wood drying science shows that high-temperature drying happens when the wood temperature exceeds 212^{o}F and the moisture in the wood changes phase from water to vapor. The wood temperature is typically lower than the air temperature in the kiln, so the phase change does not occur unless the kiln temperature is set to 220^{o}F or higher. IFG believes that it is inappropriate to apply high-temperature drying emission factors when kilns are operated below 220^{o}F.

IFG is concerned that the EPA memo used substitution of data from other wood species to an unacceptable extent. In cases where actual test data was not available for a particular wood species, data for other species was substituted. The substitution was then compounded by other assumptions until the result was an emission factor that was completely inappropriate for the original species. The effects of the compounding assumptions are most apparent in the emission factor for western red cedar, which is an important Idaho species.

The EPA memo includes VOC emission research, but then applies a procedure called Optional Test Method 26 (OTM-26) to adjust the VOC emission factors to include HAP emissions. The EPA Air Emissions Center (EMC) says that the OTM category includes test methods which have not yet been subject to the Federal rulemaking process. IFG does not want emission factors based off OTM-26 to be used in their permit. IFG has proposed VOC emission factors that are based on VOC emissions testing using EPA's adopted reference test method for VOC.

IFG proposes that the table in Permit Condition 4.6 be revised using the information contained in Attachment A. Most of the IFG emission factors are lower than the EPA December 2012 memo, with the exception of lodgepole pine dried at high-temperature. IFG's emission factor is higher because the research included a test that EPA had not included. IFG recommends the VOC emission factor table be given a Table number for ease of reference. IFG requests that the VOC emission factors be set to the following values (as propane):

Wood Species	**Kiln Temperature (°F)**	**VOC Emission Factor (as propane) (lb/mbdft)**
White Fir	≤220	0.465
	>220	0.657
Western Hemlock	≤220	0.263
	>220	0.326
Western Red Cedar	≤220	0.142
	>220	NA (not dried at hi-temp)
Douglas Fir	≤220	0.744
	>220	1.476
Engelmann Spruce	≤220	0.135

Wood Species	Kiln Temperature (°F)	VOC Emission Factor (as propane) (lb/mbdft)
Engelmann Spruce	>220	0.135
Larch	≤220	0.263 (hemlock)
	>220	0.326 (hemlock)
Lodgepole Pine	≤220	1.052
	>220	1.695
Ponderosa Pine	≤220	1.909
	>220	3.671
Western White Pine	≤220	2.766
	>220	2.766
Any Other Type	≤220	2.766
	>220	3.671

IFG requests that DEQ add a sentence stating that when tracking a multiple species group, the permittee will use the highest emission factor for any wood species in the group. This will make it clear that IFG is allowed to track typical wood groups such as hemlock and fir (HF) or Douglas fir and larch (DFL).

DEQ Response: Added a table number in the permit to the VOC Emission Factor Table, and added the verbiage for tracking a multiple species group.

The following responses are based off of the research articles submitted by IFG, articles EPA Region 10 used to generate the December 2012 VOC and HAP emission factors for lumber drying in large scale kilns, and information received from EPA Region 10 May 21, 2019.

<u>Temperature Response:</u>

July/August 2008, Mike Milota and Paul Mosher published a research article, “Emissions of Hazardous Air Pollutants from Lumber Drying”. This article used NCASI Method 105 during lumber drying to measure HAP emissions of methanol, phenol, formaldehyde, acetaldehyde, propionaldehyde, and acrolein from red alder, ponderosa pine, white wood, douglas fir, western hemlock, and white spruce. The results indicate a strong dependence on temperature for methanol and formaldehyde, in that these emissions increase with increasing temperature.

March 23, 2007, Michael R Milota in the Department of Wood Science and Engineering, from Oregon State University published a research article, “VOC, Methanol, and Formaldehyde Emissions from the Drying of Hemlock, ESLP, and Douglas-fir Lumber”. This article discussed how VOC emissions are generated as the moisture content is decreased within the lumber being dried. This explains the correlation between initial moisture content, time in the kilns, and temperature. Please note that due to seasonal changes wood can have varying initial moisture content which is not a controlled factor. The graphs within this article demonstrate how the emission generation during dry time and temperature are not a linear process. Table 6, “Comparison of Results to Past Work”, show a clear temperature dependence on Hap and VOC emissions.

May 2006, Michael R. Milota and Paul Mosher published a research article, “Emissions from Western Hemlock Lumber during Drying”. This article establishes how emissions are dependent upon initial moisture content, seasonal conditions, drying temperature, log storage, and the exponential relationship. The graphs indicate above

200°F HAP emissions more than double.

March 2003, Michael R. Milota published a research article, "HAP and VOC emissions from white fir lumber dried at high and conventional temperatures". EPA Method 25A and NCASI chilled impinger method was used for methanol and formaldehyde. This article supports that VOC emissions more than doubled for wood dried at higher temperatures, methanol emissions increased by 240 percent, and formaldehyde increased by 470 percent. The two drying temperatures were 179.96°F and 240.08°F.

Two research papers were published, one on August 24, 2004, and the other October 15, 2004. Both were on VOC, methanol and formaldehyde emissions from drying hemlock lumber. The August paper used initial moisture contents of 56.8 and 51.1 percent, 180°F drying temperature, and a final moisture content of approximately 15 percent. The October paper used initial moisture content of 76.0 percent, 200°F drying temperature, and final moisture content of approximately 15 percent. The data contained in the table listed below was pulled from these two articles and supports how emissions are temperature dependent with 200°F being the significant threshold before emissions become exponential according to high drying temperatures.

Table 7 Temperature and Emissions

Temperature (°F)	VOC (lb/mbf)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)
180	0.198	0.0312	0.00082
180	0.122	0.0304	0.00082
200	0.204	0.057	0.0014

July/August 2004 Brad Fitz, Brian Lamb, Hal Westberg, Richard Folk, Berk Knighton, and Eric Grimsrud published a research paper, "Pilot-and Full-Scale Measurements of VOC emissions from Lumber Drying of Inland Northwest Species". This article supports that VOC emissions are non-linear according to drying temperatures and that 50 percent of the VOC's are released within the first 5 hours of drying.

The research papers referenced above are just a few examples of documents EPA Region 10 used to publish the December 2012 VOC and HAP emission factors. EPA Region 10 has taken this data and used it to find the best fit linear equation for each wood species. This method accounts for the temperature dependent compounds such as formaldehyde and methanol, while also allowing the facility to use the highest 60-minute average dry bulb temperature of heated air that enters a load of lumber in any zone of the kiln, rather than a high and low temperature threshold.

<u>Assumption and Wood Data Substitution Response:</u>

December 20, 2012, EPA Region 10 drafted a letter to Mr. Michael Simon, Stationary Source Program Manager at Idaho Department of Environmental Quality notifying IDEQ, EPA Region 10 explained to companies in 2007, "new emission factors are developed from time to time through new research or testing; EPA expects facilities to use the best data available for estimating emissions. The enclosed table presents emission factors that EPA considers most appropriate today for lumber kilns". The enclosed table is the December 2012 EPA Region 10 VOC and HAP emission factors.

The letter continues to explain how 18 more tests have been added to the database from which emission factors were calculated and they refined the approach for developing emission factors. "Rather than using the average values, we are using the 90th percentile value for species-specific data sets with more than two data points and the maximum value for specie-specific data sets with two or fewer data points." In the December 2012 published VOC and HAP emission factors supporting documents explain how if there was no data, data for similar species was used, keeping the distinction between soft wood, hard wood, resinous and non-resinous wood, the highest emission factors for the similar species was substituted. This approach was adopted because it assured adequate conservatism to be able to rely on the emission factors for applicability and compliance determinations. The letter further explains most emission factors have increased, most notably the emission factors for methanol which more than doubled when drying douglas fir and white fir at high temperatures. The letter states EPA plans to require the use of these new emission factors beginning later this winter for sources operating in Indian Country throughout the Pacific Northwest, and that EPA plans to specify the recommended emission factors in future permit actions (revisions, renewal, and initial issuance) that house synthetic minor limits.

Western red cedar response:

According to the December 2012 EPA Region 10 published VOC and HAP emission factor table and supporting documents, "western red cedar is similar to white fir and western hemlock in that all three species are non-resinous softwood species in the scientific classification order Pinales". IDEQ cannot find where this information is incorrect and concurs with EPA Region 10 in their justification to use the substituted data for this wood species.

OTM-26 response:
Method 25A was originally used to measure volatile organic compounds from lumber drying kilns, this method measured carbon atoms through the following procedure, "a gas sample is extracted from the source through a heated sample line and glass fiber filter to a flame ionization analyzer (FIA). Results are reported as volume concentration equivalents of the calibration gas or as carbon equivalents."

On July 12, 2006, Mr. William Wehrum, EPA Acting Assistant Administrator, sent a letter to Mr. Timothy G. Hunt, Senior Director, Air Quality Programs, at the American Forest and Paper Association regarding the recently discovered issue that Method 25A is not able to capture the carbon in oxygenated (oxygen containing) organic compounds, and outlined a path forward for the complex issue of measuring and reporting volatile organic compounds (VOCs) in the forest products industry. Thus VOC emissions were being under reported for facilities where formaldehyde and methanol emissions are significant.

This short fall was identified in EPA's, "Interim VOC Measurement Protocol for the Wood Products Industry – July 2007". Where EPA states they are endorsing OTM-26 to run separate speciated tests for methanol, formaldehyde, and other known compounds in an effort to get a more accurate measurement of a facility's VOC emissions, and to use in the determination of major source applicability of federal programs. Under supporting documentation for this protocol on EPA's webpage it lists under, "Other Validation", Laboratory and Field Evaluation by National Council (NCASI) sponsored by American Forest and Paper Association.

OTM-26 requires EPA Method 25A to be used for the Total Hydrocarbon (THC) measurement with the following specifications:

- The THC portion of the VOCs shall be expressed as propane.
- For some facilities, in states where it is the current practice, it may be appropriate to report the THC portion of the VOCs as terpenes (as alpha-pinene) rather than propane.
- The reporting basis for VOC should be clearly identified.

Total VOCs would then equate to the following equation:

$$\mathrm{VOC} = \begin{bmatrix} \begin{pmatrix} \text{Method 25A VOC} \\ \textit{expressed as propane} \end{pmatrix} \\ \\ +\begin{pmatrix} \text{Methanol} \\ \textit{expressed as methanol} \end{pmatrix} \\ \\ +\begin{pmatrix} \text{Formaldehyde} \\ \textit{expressed as formaldehyde} \end{pmatrix} \end{bmatrix} - \begin{pmatrix} \sum_{i=1}^{n} (\mathrm{RF}_i \text{ x } \mathrm{Compound}_i) \\ \textit{expressed as propane} \end{pmatrix}$$

Where: RF_i = response factor of $_i$th compound (expressed as a decimal)

It is this equation that will capture the oxygenated (oxygen containing) organic compounds EPA Method 25A is not able to detect.

VOC Emission Factor Response:

According to the research documents submitted by IFG, EPA Region 10 December 2012 VOC and HAP emission factor determination, information received from EPA Region 10 May 21, 2019, and the analysis listed above as DEQ's response, the best available data to measure emissions is the best fit linear equations approached received from EPA Region 10 received May 21, 2019, which provides a sliding scale for the highest 60-minute average dry bulb temperature of heated air that enters a load of lumber in any zone of the kiln. The following is a table of best fit equations specific to wood species:

X is the highest 60-minute average dry bulb temperature of the heated air that enters a load of lumber in any zone of the kiln (°F) measured and recorded for that batch.

Example: Drying Douglas Fir at 220°F, WPP1 VOC Emission Factor =0.0151(220)-1.7646
Multiply 0.0151 by 220 and subtract 1.7646 for the WPP1 VOC emission factor in lb/mbdft.

Table 4.3 VOC Emission Factors

Species	WPP1 VOC[a,b] Emission Factor (lb/mbdft)
Non-Resinous Softwood Species	
Western True Firs[c]	0.0066X-0.5804
Western Hemlock	0.0037X-0.3085
Western Red Cedar	0.0066X-0.5804
Resinous Softwood Species	
Douglas Fir	0.0151X-1.7646
Engelmann Spruce	0.2142
Larch	0.0151X-1.7646
Resinous Softwood Species (Pine Family)	
Lodgepole Pine	1.4031
Ponderosa Pine	0.0292X-2.4636
Western White Pine	0.0292X-2.4636

a) VOC emissions approximated consistent with EPA's Interim VOC Measurement Protocol for the Wood Products Industry – July 2007 (WPP1 VOC). WPP1 VOC underestimates emissions when the mass-to-carbon ratio of unidentified VOC exceeds that of propane. Ethanol and acetic acid are examples of compounds that contribute to lumber drying VOC emissions (for some species more than others), and both have mass-to-carbon ratios exceeding that of propane. Contribution of ethanol and acetic acid to VOC emissions has been quantified here when emissions testing data is available.
b) Because WPP1 VOC, methanol and formaldehyde emissions appear to be dependent upon drying temperature, a best-fit linear equation with dependent variable maximum drying temperature has been generated to model emissions. Single values have been generated when limited underlying test data is representative of high-temperature drying.
c) Western true firs consist of the following seven species classified in the same Abies genus: bristlecone fir, California red fir, grand fir, noble fir, pacific silver fir, subalpine fir, and white fir.
d) When tracking a multiple species group, the permittee shall use the highest emission factor for any wood species in the group.

This approach incorporates OTM-26, however it allows for the facility to use the highest 60-minute average dry bulb temperature of the heated air that enters a load of lumber in any zone of the kiln (°F) measured and recorded for that batch specific to a certain wood species, and calculate the correct emission factor in an effort to determine the actual VOC's from the kilns, rather than only using a high and low drying temperature threshold.

Facility Comment: Page 16, Permit Condition 4.7. 'Federal Regulatory Analysis'.

DEQ Response: Page 16, Permit Condition 4.7. 'Federal Regulatory Analysis' has been updated to reflect the facility's request.

Facility Comment: Page 17, Permit Condition 5.2, Table 5.1 (not 4.1).

Each of the controlled cyclones have different baghouses. This table should be consistent with Table 1-1 and the reference to PM_{10} control efficiency should be eliminated. Planer not Planer.

DEQ Response: Page 17, Permit Condition 5.2, Table 5.1 (not 4.1) has been updated to reflect the facility's request.

Facility Comment: Page 18, Permit Condition 5.3.1.

The wording of the final sentence has been changed from the current Permit Condition 4.6. It should say: 'Each Baghouse shall be operated at all times that the cyclone it is connected to is operating.' Planer not Planer.

DEQ Response: Page 18, Permit Condition 5.3.1 has been updated to reflect the facility's request.

Facility Comment: Page 18, Permit Condition 5.6.

This permit condition has changed and should be marked DRAFT. The wording has been changed from the original Permit Condition 4.13. This permit condition now requires monitoring of the pressure drop across the cyclones instead of the baghouses. IFG asks that this permit condition be revised to monitoring baghouse pressure drop and be marked DRAFT.

DEQ Response: Page 18, Permit Condition 5.6 has been updated to reflect the facility's request.

Facility Comment: Page 19, Permit Condition 6.3. 'Federal Regulatory Analysis'.

DEQ Response: Page 19, Permit Condition 6.3. 'Federal Regulatory Analysis' has been updated to reflect the facility's request.

Facility Comment: Page 20, Permit Condition 7.6.

The required notifications were provided to DEQ when the facility was built. There is no construction associated with the current PTC. IFG would like the permit to acknowledge that these requirements have been met, if that is possible.

DEQ Response: This is a general provision from standard DEQ language contained in all new or modified permits, this shall remain unchanged.

The following comments were received from the facility on June 27, 2019:

Facility Comment: IFG would like to thank DEQ representatives for meeting with IFG to discuss the revised facility draft for permit P-2008.0204. IFG reviewed the first facility draft and DEQ considered each of the IFG suggested changes. The only IFG comments on the second facility draft permit are related to **Section 4, Dry Kilns.**

Conditions 4.1, 4.2 and 4.3 are unchanged.

DEQ Response: IDEQ Concurs.

Facility Comment: As we discussed in the meeting, the purpose of permit **Condition 4.4** has changed because the form of the VOC emission limit and monitoring requirements have changed. IFG is aware that some form of operating requirement is needed. We propose changing the kiln operating limit to the maximum production per day, which will serve to limit and provide a basis for the kiln PM emissions. The emission inventory submitted with the PTC application was based on 2,000 thousand board feet per day (mbf/day) maximum. All the $PM_{10}/PM_{2.5}$ 24-hour emissions were calculated from 2,000 mbf/day.

Kiln testing has resulted in updated PM_{10} emission factors that are lower than the factors used in the original permit application for this facility. The original analysis for the current Grangeville permit was based on PM_{10} emissions from the kilns of 135.6 pounds per day (lb/day) and 24 tons per year (tpy). The updated kiln PM_{10} emission factor is 0.038 pounds per thousand board feet (lb/mbf) resulting in Kiln PM_{10} emissions estimates/potential emissions that are lower than the original estimates/potential emissions as shown below:

0.038 lb/mbf * 2,000 mbf/day = 76.0 lb/day

76.0 lb/day * 365 days/year ÷ 2,000 lb/ton = 13.9 tpy

The following is IFG's proposed language for the kiln production limit:

4.4 Dry Kiln Maximum Production Limit

The maximum daily lumber produced from all dry kilns combined shall not exceed 2,000 thousand board feet per calendar day (mbf/day).

DEQ Response: Permit Condition 4.4 shall remain unchanged in this project, as this established the annual PM_{10} emission limit as modeled in the 2006 permit. If the facility would like this changed an additional review can be conducted under an additional project as modeling files for PM_{10} and $PM_{2.5}$ will need to be submitted for an analysis.

Facility Comment: IFG and DEQ discussed adding kiln temperature tracking to permit **Condition 4.5**. IFG proposes adding 'Temperature' to the heading, changing the production monitoring unit to thousand board feet (mbf), and adding a second paragraph as follows:

4.5 Dry Kiln Production and Temperature Monitoring

Each month, the permittee shall monitor and record the following kiln production information in units of thousand board feet per month (mbf/mo) and thousand board feet per the most recent consecutive 12-month period (mbf/yr):

- The quantity of each species of wood processed in all of the kilns; and
- The total sum of all wood species processed in all of the kilns.

For each dry kiln charge, the permittee shall monitor and record the following information:

- Starting and ending date/time of drying.
- All species of wood contained in the kiln charge.
- The total quantity of lumber present in the kiln charge, in units of thousand board feet (mbf).
- The maximum dry kiln set point used for drying the kiln charge, in units of degrees Fahrenheit (^{o}F).

DEQ Response: IDEQ Concurs, the requested revision has been incorporated into the permit.

Condition 4.6 contains the methodology for preforming the VOC emissions calculations. IFG is proposing that the requirement contained in footnote 4 to **Table 4.3** be moved to a bullet point and that the VOC summation procedure be more fully described. IFG would prefer that all the footnotes to Table 4.3 be changed as shown below for clarity. The hemlock and cedar categories have been generalized, as explained in the footnotes. A final category has been added for any other species not listed, and it has been assigned the highest emission factor. The language allowing DEQ to approve other emission factors has been reinstated.

IFG is proposing that **Condition 4.6** be changed as follows:

4.6 VOC Emissions Calculations

Each month, the permittee shall calculate the tons of VOC emissions from the dry kilns during the previous consecutive 12-month period to demonstrate compliance with the annual VOC emission limit for the kilns.

- VOC emissions from all of the kilns shall be calculated using the kiln production information monitored as per **Condition 4.5** and VOC emissions factors/equations contained in **Table 4.3** (or factors approved by DEQ in writing). The value X in the emission factor equations is the kiln set point temperature monitored as per **Condition 4.5**.
- When tracking a multiple-species charge, the permittee shall use the highest emission factor for any wood species in the charge.

Table 4.3 Kiln VOC Emission Factors

Species	VOC Emission Factor (lb/mbf)
Western True Firs[1]	0.0066X – 0.5804
Hemlock[2]	0.0037X – 0.3085
Cedar[3]	0.0066X – 0.5804
Douglas fir	0.0151X – 1.7646
Engelmann Spruce	0.2142
Larch	0.0151X – 1.7646
Lodgepole Pine	1.4031
Ponderosa Pine	0.0292X – 2.4636
Western White Pine	0.0292X – 2.4636
Other Species not Listed	0.0292X – 2.4636

[1] Western true firs consist of the following seven species classified in the same Abies genus: bristlecone fir, California red fir, grand fir, noble fir, pacific silver fir, subalpine fir, and white fir.

[2] Includes western hemlock and mountain hemlock.

[3] Includes western red cedar and any other cedar species.

- VOC emission factors are developed using kiln set point temperature and **Table 4.3** following the example below for drying Douglas fir at 220°F:

  *VOC emission factor = 0.0151 * (220) – 1.7646 = 1.5574 lb/mbf*

- Monthly kiln VOC emissions shall be calculated using the quantity and species for each kiln charge and the VOC emission factor calculated based on the set point temperature for that kiln charge.
- Rolling 12-month total VOC emissions are calculated by adding up the total VOC for 12 consecutive months.
- The table below shows a sample monthly tracking methodology

Example Kiln VOC Emissions Tracking Methodology

Month:	**August 2019**				
Charge ID	**Species**	**Quantity (mbf)**	**Set Point T(oF)**	**VOc e.f. (lb/mbf)**	**VOC Emissions (tons)**
K1-A	white fir	250	200	0.7396	0.0925
K2-A	hemlock	350	200	0.4315	0.0755
K3-A	HF (hem-fir)	400	200	0.7396	0.1479
K4-A	cedar	300	160	0.4756	0.0713
K5-A	Douglas fir	400	220	1.5574	0.3115
K1-B	larch	300	220	1.5574	0.2336
K2-B	DFL	400	220	1.5574	0.3115
K3-B	E. spruce (es)	400	220	0.2142	0.0428
K3-B	lodgepole (lp)	300	235	1.4031	0.2105
K4-B	eslp	325	220	1.4031	0.2280
K5-B	p.pine	275	180	2.7924	0.3840
	Monthly Total	3,700			2.109

IFG and DEQ agreed to include a requirement for a dry kiln operations and maintenance (O&M) manual. IFG has based the proposed **Condition 4.7** on the boiler O&M manual requirement from this permit with some kiln-specific requirements included based on a sample EPA O&M manual requirement.

DEQ Response: IDEQ Concurs, the requested revision has been incorporated into the permit, with the exception of the sample table.

Facility Comment: ***4.7 Operations and Maintenance Manual Requirement***

Operation and Maintenance manuals (or a single manual) shall be developed and maintained for each of the dry kilns. The permittee shall develop and maintain the kiln O&M manual(s) according to manufacturer specifications and recommendations. The manual(s) shall be revised within 30 days of issuance of this permit to incorporate the changes made as part of this permit modification.

This manual shall describe the methods and procedures that will be followed to ensure the kilns and kiln control systems are maintained in good working order and operated as efficiently as practical. The O&M manuals shall be updated as necessary and shall include the following, at a minimum: air temperature measurement systems used in the kiln(s); door seals and kiln structural integrity; kiln steam system; kiln control PC interface system; inspection procedures and inspection frequency; upset conditions guidelines; and corrective action procedures.

DEQ Response: IDEQ Concurs, the requested revision has been incorporated into the permit.

Facility Comment: Condition 4.8 is unchanged.

DEQ Response: IDEQ Concurs.

The following comments were received from the facility on November 21, 2019:

Facility Comment: Permit Condition 1.1 add, "of wood residue".

DEQ Response: The facilities requested change shall be made, "of wood residue" has been added.

Facility Comment: Permit Condition 2.6 third paragraph first sentence, change in to on.

DEQ Response: The facilities requested change shall be made, "in" was changed to "on".

Facility Comment: Permit Condition 2.10 change title from, "Facility-Wide VOC Tracking" to, "Facility-Wide VOC Emission Limit". and the following:

Don't know where 247.77 came from. The PSD-avoidance limit is 249 tpy. DEQ has assured IFG that the compliance tracking demonstrations will not become permit limits.

The permittee shall emit no more than ~~247.77~~249 tons per year (tpy) of VOC's. VOC emissions from the dry kilns, ~~hog boiler wood-fired~~hog fuel boiler, and pneumatic conveyance of wood residue shall be tracked as per Permit Conditions ~~3.5, 4.6, 5.3~~ 3.12, 4.6 and 5.8 to demonstrate compliance with this requirement. For purposes of complying with this requirement, a year is defined as any consecutive 12-month period.

DEQ Response: The facilities requested change shall be made; the title of Permit Condition 2.10 has been changed to, "Facility-Wide VOC Emission Limit.

247.77 tons per year was from the emissions inventory IFG submitted. This emission limit has been increased to facility wide 249 tons per year.

"of wood residue" has been added, and the permit conditions in this paragraph have been updated.

Facility Comment: Update Permit Condition 3.1 with the following language, "The Wellons ~~hog~~ fuel cell ~~wood-fired~~ boiler burns shredded (hogged) wood and bark to supply ~~supplies~~ up to 80,000 pounds per hour of steam to five kilns which are used to dry lumber. The rated heat input capacity of the boiler is 116 MMBtu/hr."

DEQ Response: The facilities requested change shall be partially made; Permit Condition 3.1 has been updated to reflect the requested language, with the exception that the boiler will be called, "Hog Fuel Boiler", as this matches the emissions unit in Table 1.1 for the regulated sources within the permit.

Facility Comment: Permit Condition 3.2 update the, "Emissions Units/Processes in Table 3.1 to the following description, "~~Hog~~ Boiler burning shredded (hogged) wood and bark ~~Wood-Fired~~".

DEQ Response: The facilities requested change shall be partially made; the emissions unit must be labeled as, "Hog Fuel Boiler", as this matches the emissions unit in Table 1.1 for the regulated sources within the permit. However, "burning shredded (hogged) wood and bark has been added as the process.

Facility Comment: Permit Condition 3.3 has the following comment, "Condition 3.4 from the July 2019 public comment draft has been moved to 3.5."

DEQ Response: The facilities comment shall be noted; there is nothing to add or change to Permit Condition 3.3.

Facility Comment: Permit Condition 3.4. Remove VOC from the title, and update the Table 3.2 as follows:

Table 3.8 Hog Fuel Boiler ~~Wood-Fired~~Emissions Limits[a]

Source Description	~~VOC~~	NOX	CO
	~~T/yr (b)~~	T/yr (b)	T/yr (b)
Hog Boiler Wood-Fired	~~25.36~~	~~127.00~~249	101.00

a) In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.

DEQ Response: The facilities requested change shall be partially made; "VOC" has been removed from the title of Permit Condition 3.4.

The title of Table 3.2 has been updated to state, “Hog Fuel Boiler” to be consistent with Table 1.1, regulated sources. The source description has been revised to, “Hog Fuel Boiler”.

VOC emission limit has been removed.

The current permit was based on a manufacturer suggested NO_X emission factor of 0.25 lb/MMBtu. The boiler has a maximum heat input capacity of 116 MMBtu/hr, this equates to potential NO_X emissions of 111 tpy. There is no assurance from the manufacturer that this emission factor is representative of emissions across a range of steaming rates and exhaust temperatures and O_2 concentrations, therefore IFG has proposed to use EPA’s AP-42 NO_X emission factor of 0.49 lb/MMBtu. Using EPA’s AP-42 NO_X emission factor of 0.49 lb/MMBtu and the maximum heat input capacity of 116 MMBtu/hr this equates to a potential NO_X emission of 249 tons per year. Therefore the NO_X emission limit has been increased to 249 tons per year and the emission factor has been changed to EPA’s emission factor of 0.49 lb/MMBtu, until the boiler can be source tested to confirm the NO_X emission factor and the actual emissions.

Footnote b has been added to explain the emissions are in tons per consecutive 12-calendar month period.

Facility Comment: Move Permit Condition 3.5 under Permit Condition 3.12.

DEQ Response: The facilities requested change has been made; as this falls under monitoring and recordkeeping this Permit Condition has been moved under Permit Condition 3.12.

Facility Comment: Permit Condition 3.12, the boiler emissions are based on actual steam, not on a fixed steaming rate. The emissions can be calculated using the source test result, as long as it is not greater than the emission factor. If the source test is higher than the emission factor, IFG needs to modify the permit.

DEQ Response: The facilities requested change has been made; Permit Condition 3.12 has been revised to use the actual boiler steam production as tracked in Permit Condition 3.11. Permit Condition 3.11 was established in the PTC issued February 17, 2009. The emissions shall be calculated using these emission factors until a source test can be completed to verify these emission factors and/or establish new emission factors, at which time can be incorporated into the permit to calculate and track the actual emissions.

Facility Comment: Permit Condition 3.13, change numbering from 3.4 and 3.5.1 to 3.5 and 3.6.1.

DEQ Response: The facilities requested change has been made; the numbering has been revised to reference the correct permit conditions.

Facility Comment: It would be ok to conditions 3.15, 3.16 and 3.17 into a single testing condition.

Change the language to the following:

The permittee shall complete a source test no later than three years from issuance of this permit to ~~confirm~~ determine the Wellons Hog Boiler Wood-Fired VOC emission factor. The test shall be conducted to verify the emission factor contained in Permit Condition 3.12. ~~demonstrate compliance with the emission rate limits specified by Permit Conditions 3.4.~~ Each performance test conducted to demonstrate compliance shall be performed in accordance with IDAPA 58.01.01.157.

DEQ Response: The facilities requested change shall be partially made; Permit Conditions 3.15, 3.16, and 3.17 have been combined.

This source test is to verify the emission factors used in the permit to calculate and demonstrate the facilities potential emissions are accurate. As the emission factors used is also responsible for the set emission limits within the permit, emission limits shall also be verified to determine if there has been an exceedance.

Facility Comment: Permit Condition 4.3, the kiln VOC emission limit is replaced by the facility-wide VOC emission limit. There is no separate sub-limit for the kilns.

The VOC emissions from all dry kiln vents combined shall be tracked to verify compliance with the facility-wide VOC emissions limit contained in Permit Condition 2.10. ~~not exceed any corresponding emissions rate limits listed in Table 4.2.~~

~~Table 4.2 Dry Kilns Total Combined Emission Limits[(a)]~~

~~Source Description~~	~~VOC~~
	~~T/yr (b)~~
~~Five dry kilns~~	~~211.00~~

~~a) In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.~~

~~b) Tons per any consecutive 12-calendar month period.~~

DEQ Response: The facilities requested change shall be made; the kiln emission limit shall be removed as it is included in the facility-wide VOC emission limit of 249 tpy and the language has been changed.

Facility Comment: Permit Condition 4.6 change the language to:

Each month, the permittee shall calculate the tons of VOC emissions from the dry kilns during the previous consecutive 12~~-~~month period to demonstrate compliance with the annual facility-wide VOC emission limit ~~for the kilns~~in condition 2.10.

We would prefer that this referenced Permit Condition 4.5 for clarity. But IFG made that comment on the last draft and it was rejected.

Please get assurance in writing from EPA that they aren't going to change these again - before issuing the public comment draft. Thanks.

California is capitalized in California red fir. I looked it up.

DEQ Response: The facilities requested change shall be made; the language in the first paragraph has been changed as per request.

Permit Condition 4.6 needs to reference Table 4.3 and not Permit Condition 4.5 because the temperature dependent VOC emission factor equations are not listed in Permit Condition 4.5, and these equations shall be used to demonstrate compliance with the annual VOC facility-wide emission limit.

Idaho DEQ uses the best available data and information at the time of any permitting action. EPA Region 10 forwarded revised VOC equations to IDEQ on November 22, 2019 and at IFG's request have been incorporated into this permit. Outside of this IDEQ will not be able to retain such a statement from EPA.

California has been capitalized.

Facility Comment: Permit Condition 4.7, these items belong in the O&M Manual. IFG does not understand this language. IFG and DEQ can work out the details in the review of the O&M Manual.

~~Kiln Drying Schedules and Maximum Entering-Air Temperature Determinations~~

~~The permittee shall maintain records onsite of at least two control charts ("pen charts") for each drying schedule used over the most recent five-year period, and copies of all control charts used in audits completed over the most recent five-year period. For the purposes of assessing kiln emissions for each species in facility-wide emission limits compliance monitoring, the maximum entering-air temperature ("Enter Air") determined from at least two control charts shall be used.~~

~~The maximum entering-air temperature for each schedule shall be determined as either the highest instantaneous temperature, or the highest 60-minute average temperature, exhibited in the two or more control charts evaluated (i.e., the highest maximum exhibited).~~

~~At a minimum, the entering-air maximum temperature, starting and ending times, final moisture content, and monitoring parameters for the charge processed shall be identified or recorded on each control chart evaluated.~~

Very confusing. We agree to maintain a record (one) for each charge for a period of 5 years beginning the date of Permit issuance.

DEQ Response: Permit Condition 4.7 is necessary to determine compliance with the annual facility-wide VOC emission limit and to be used in conjunction with Permit Condition 4.6. Permit Condition 4.6 requires the maximum air-entering temperature to be used in the temperature dependent VOC emission factor equations. Without Permit Condition 4.7 the facility could not demonstrate the maximum air-entering the kilns is being used. This is not an operating and maintenance procedure that belongs in an O&M Manual it is a compliance demonstration requirement that belongs in the permit.

IDEQ conducted a conference call with IFG and presented this permit condition along with copies/examples of the control charts ("pen charts"), and explained how to follow this permit condition. At that time IFG said it was feasible to follow and agreed to this permit condition.

Please note, IDEQ compliance staff in your region are available for a permit handoff meeting upon the issuance of this permit. The purpose of this meeting is to ensure the facility understands the requirements of each permit condition.

Facility Comment: Permit Condition 4.8, there are no kiln emission limits, just facility-wide emission limits.

Kiln O&M manual does not include kiln throughput monitoring. Throughput is a process function and is highly proscribed by business practices.- Adding it to the O&M manual would swamp the real intent of the O&M manual which is temperature and kiln maintenance O&M.

This is not useful and just adds unnecessary details. This comment references the wet and dry bulb temperatures of the kiln.

DEQ Response: The facilities requested changes shall be partially made; the kiln emission limits have been removed. Only facility-wide emission limits for VOC's remain.

The kiln throughput monitoring has been removed from the O&M manual as Permit Condition 4.5 addresses the kiln throughput requirement.

The monitoring the wet bulb and dry bulb temperature is a function of the kiln and a good indicator of working thermocouples. This language shall remain.

Facility Comment: Permit Condition 5.2, change to the following language:

The PM and PM_{10} emissions from the log processing, sawmill, and planer mill are controlled by the control equipment listed in ~~table~~ Table 5.1.

DEQ Response: The facilities requested change shall be made; the language shall be changed to reflect the facilities request.

Facility Comment: Permit Condition 5.3, change to the following language and make the following changes:

Pneumatic Conveyance of Wood Residue Emission Limits

The VOC emissions from all pneumatic conveyance of wood residue shall be tracked to verify compliance with the facility-wide VOC emissions limit contained in Permit Condition 2.10.~~shall not exceed any corresponding emissions rate limits listed in Table 5.2~~.

~~Table 5.2 Pneumatic Conveyance Emission Limits~~[a]

~~Source Description~~	~~VOC~~
	~~T/yr~~[b]
~~Pneumatic Conveyance~~	~~11.4~~

~~a) In absence of any other credible evidence, compliance is ensured by complying with permit operating, monitoring, and record keeping requirements.~~

~~b) Tons per any consecutive 12-calendar month period.~~

DEQ Response: The facilities requested changes have been made.

Facility Comment: Permit Condition 5.4, Move to Monitoring section, permit condition 5.8.

DEQ Response: The facilities requested change has been made.

Facility Comment: Permit Condition 5.8, make the following changes.

Pneumatic Conveyance of Wood Residue VOC Emissions Tracking

Each month, the permittee shall calculate the tons of VOC emissions from the pneumatic conveyance of wood residue during the previous consecutive 12-month period to demonstrate compliance with the facility-wide VOC emission limit contained in Permit Condition 2.10.

When tracking a multiple-species charge, the permittee shall use the highest emission factor for any wood species in the charge.

DEQ Response: The facilities requested change has been made.

The following comments were received from the facility on December 13, 2019:

Facility Comment: Permit Condition 3.12 change, "Factor" to "Factors"

DEQ Response: The facilities requested change has been made, "Factor" has been changed to "Factors".

Facility Comment: Permit Condition 3.13, PM Compliance Testing Requirements – NSPS, last paragraph and last sentence, change one of the permit conditions from 3.3 to 3.5.

DEQ Response: The facilities requested change has been partially made. Permit Condition 3.5 has been added. Permit Condition 3.3 pertains to the hourly PM_{10} emission limit that was established in the modeling analysis when the through put was increased to 250 million board feet per year, Permit Condition 3.5 pertains to the particulate matter emission limit in accordance to 40 CFR 60.43(c)(1), and Permit Condition 3.6 pertains to the opacity limits in accordance with 40 CFR 60.43(b)(f). Permit Condition 3.13 now references Permit Conditions 3.3, 3.5, and 3.6.

Facility Comment: Permit Condition 3.15, change, "Test" in the header to "Tests" and change, "factor" to "Factors" in the first sentence.

DEQ Response: The facilities requested change has been made, "Test" has been changed to "Tests", and "factor" has been changed to "Factors".

Facility Comment: Permit Condition 4.6, change "Schedule" to "Schedules".

DEQ Response: The facilities requested change has been made, "Schedule" has been changed to "Schedules".

Facility Comment: Permit Condition 5.2, "Odd table break".

DEQ Response: Due to formatting this table was allowed to be split onto the next page using the same headers.

Facility Comment: Permit Condition 6.1 change, "monthly" to "weekly".

DEQ Response: The facilities requested change has been made, "monthly" has been changed to "weekly".

ATTACHMENT A

Evaluation of Dry Kiln Emission Factors
Presented to Idaho Department of Environmental Quality

Table of Contents

I. Executive Summary

This document describes a compilation of available lumber dry kiln emissions tests that are relevant to Idaho wood species. The dry kiln test data has been used to develop suggested emission factors to be used in air quality emissions inventories and permitting for lumber kilns. All the test data has been collected from indirectly heated dry kilns so the emission factors may not be applicable for direct-fired dry kilns in which combustion products are introduced into the kiln.

The emissions test reports are listed in the Reference section of this document and have been provided to Idaho DEQ electronically. The test results have been complied in Excel spreadsheet files that been presented as printouts in the appendices this report and have also been provided electronically to Idaho DEQ.

Dry Kiln test results referenced in this analysis have been used to develop suggested dry kiln emission factors for the following criteria air pollutants and hazardous air pollutants (HAPs):

- Particulate matter smaller than 10 µm (PM_{10})
- Particulate matter smaller than 2.5 µm ($PM_{2.5}$)
- Volatile Organic Compounds (VOC)
- Methanol
- Formaldehyde
- Acetaldehyde
- Propionaldehyde
- Acrolein

II. Compilation of Dry Kiln Test Data

Available dry kiln emission tests dating from 1996 through 2015 have been complied and reviewed for this analysis. The kiln emissions test reports are listed in the reference section of this report and have been made available to Idaho DEQ electronically. The VOC and HAP emission tests are described in this section. Particulate matter tests are discussed below.

The earliest study included in this analysis was performed in 1996 at the University of Idaho under contract to the National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI). This study used EPA Reference Method 25A to measure VOC emissions from thirteen southern and western species of softwood lumber. The lumber was tested in a small-scale kiln under drying conditions similar to those for full-scale kilns (U of Idaho 1996). The VOC test results for Douglas fir, ponderosa pine, cedar, white fir, grand fir, hemlock, and white pine were used in this analysis.

Dr. Michael R. Milota of the Oregon State University (OSU) Department of Forest Products has been a lead researcher on dry kiln emissions studies for many years in the Pacific Northwest. In 2000, Dr. Milota conducted an extensive study on behalf of the Intermountain Forest Association (IFA 2000). The IFA study included ponderosa pine, white fir, lodgepole pine and Douglas fir. The testing for ponderosa pine, white fir and Douglas fir was done at conventional drying temperatures with a top temperature of 180°F. The lodgepole testing was done using a high-temperature drying schedule with a top temperature of 240 °F. The full IFA study, including the data spreadsheets is included with the references provided electronically to Idaho DEQ.

In 2003, Dr. Milota published a study in the Forest Products Journal which compared the HAP and VOC emissions from white fir lumber dried at high and conventional temperatures (Milota 2003). This study is an important reference for the differences in emissions at conventional drying schedules and high-temperature drying schedules. The objective of this work was to determine the extent to which drying temperature affects emissions. White fir (*Abies* spp.) is a common name for a mixture of several species of true fir grown in the West. It is dried commercially at both conventional and high-temperatures. For this study, white fir was kiln-dried at conventional (180°F) and high (240°F) temperatures, and measurements of HAPs (methanol and formaldehyde) and VOC were made (Milota 2003).

Additional dry kiln HAP and VOC emissions tests have been conducted for many years. The southwest Clean Air Agency (SWCAA) in Washington maintains a library of dry kiln emission test reports on their website (www.swcleanair.org).

III. Comparison of Conventional Temperature and High Temperature Drying

Each small-scale dry kiln test report lists the target drying temperature, which would correspond to the kiln set point in a full-scale operation. Lumber dry kiln VOC and HAP emissions test results have been found to vary with dry kiln temperature. This section describes the lumber drying schedules used in commercial softwood lumber kilns. The following description of commercial dry kiln operations was taken from the US forest Service Dry Kiln Operators Manual (USDA 1991):

Most lumber dry kilns are designed to operate within a specified range of temperatures. This range depends largely on the species to be dried and quality and end use of final products. Also considered are amount of production expected, source of energy, and limitations of certain components of the system, such as compressors and electric motors. A common classification of kilns based on maximum operating temperatures is as follows: Low-temperature kiln up to 120 °F, Conventional-temperature kiln up to 180 °F, Elevated-temperature kiln up to 211 °F, High-temperature kiln above 212 °F.

Conventional-temperature kilns typically operate in the range of 110 to 180 °F. These include steam-heated kilns and those designs of dehumidification kilns that operate up to 160 °F. The bulk of the kiln schedules available for the various species and thicknesses are for kilns operating at "conventional temperature." Elevated-temperature kilns typically operate in the range of 110 to 211 °F. The final dry-bulb temperature in a schedule for use in an elevated-temperature kiln is commonly 190 or 200 °F and occasionally as high as 210 °F. Many western softwood operations and some southern pine operations have kilns operating in this range. High-temperature kilns typically operate for most of the drying schedule at temperatures above 212 °F, usually in the range of 230 to 280 °F. These kilns are more often used for drying *construction-grade lumber where some surface checking and end splitting are acceptable in the grade, rather than upper-grade lumber where these defects are less acceptable.*

Review of the literature shows that high-temperature drying happens when the wood temperature exceeds 212°F. The kiln set point is based on kiln air temperature and can be as high as 220°F without entering the high-temperature drying regime. High-temperature drying involves a kiln set point of at least 235°F (Milota 3008). A kiln set point of 220°F has been used in this analysis as the dividing temperature between conventional drying and high-temperature drying.

IV. Development of Particulate Matter Emission Factors

Particulate matter (PM) test data is more difficult to collect from dry kilns because of the need for isokinetic sampling rates. Three PM emission tests have been identified and included in the references for this analysis. Two tests were performed in 1998 by Horizon Engineering on behalf of Willamette Industries, using the OSU test kiln in Corvallis, Oregon. The third test was performed in 2013 by Emission Technologies on behalf of Sierra Pacific Industries at a pilot kiln located in Ferndale, Washington.

The Sierra Pacific particulate matter test used a combined EPA Method 5 and Method 202 sampling train which also measures total, filterable, and condensable particulate matter. This test consisted of two sampling runs which are listed separately in the PM spreadsheet in Appendix A. The filterable particulate matter is referred to as "front half" catch and the condensable particulate matter is referred to as "back half" catch.

The two Willamette kiln tests used Oregon DEQ Method 7, which also measures total, filterable, and condensable particulate matter. The Oregon DEQ Method 7 sampling train includes the normal "front half" heated probe and filter material specified in EPA Method 5 as well as condensable material caught in the impingers in the "back half" of the train and a back half filter located between the last two impingers. Each test consisted of two test runs which are listed separately in the PM spreadsheet in Appendix A.

The total PM, both front half and back half, is all assumed to be smaller than 10 μm in size and is included in the PM_{10} emission factor. The test results have been averaged to obtain a PM_{10} emission factor of 0.0321 pounds per thousand board feet (lb/mbf). The back-half test results represent the fine particulate matter and make up the $PM_{2.5}$ emission factor. The average $PM_{2.5}$ emission rate for all tests is 0.0264 lb/mbf.

The first Willamette test and the Sierra Pacific test were made while hemlock lumber was being dried. The second Willamette test was made while Douglas fir was being dried. Conventional drying temperatures were used for all three PM tests. The test results summary in Appendix A show no discernable difference between test results using hemlock and test results using Douglas fir. The 1998 hemlock test results were higher than the 1998 Douglas fir test results, but the 2013 hemlock test results correlated well with the 1998 Douglas fir test results.

V. Development of VOC and HAP Emission Factors

A summary of the VOC test data is presented in Appendix B, followed by calculations for individual wood species. VOC emissions are measured using EPA Reference Method 25A and reported in units of lb/mbf as carbon. The test results have been standardized to units of lb/mbf as propane, based on previous recommendations by Idaho DEQ. The emission factor units are clearly marked on the spreadsheets.

A summary of the HAP test data is presented in Appendix C, followed by calculations for individual wood species. All available test data was used in the analysis, and the source of the data is identified based on the list of references in this report. The test results have been averaged to obtain a representative value for each HAP and each drying temperature range.

In cases where data was not available for a species or temperature range, it was noted. The VOC and HAP emissions spreadsheets contain suggestions for emission data which could be substituted, but no data substitution has been done. This emissions analysis only is based only on directly measured emissions and approved EPA Reference methods.

VI. References

(Columbia Vista 2005) VOC Emissions from the Drying of Douglas-fir Lumber. Report by M. R. Milota to Columbia Vista Corporation. June 14, 2005.

(Columbia Vista 2010) VOC Emissions from the Drying of Douglas-fir Lumber. Report by M. R. Milota to Columbia Vista Corp. November 12, 2010.

(Columbia Vista 2015) Total hydrocarbon and HAP emissions from the drying of Douglas-fir lumber. Report by M. R. Milota to Columbia Vista Corporation. March 24, 2015.

(Fritz 2004) Pilot- and Full-Scale Measurements of VOC Emissions from Lumber Drying of Inland Northwest Species. Brad Fritz, 2004. Forest Prod. J. 54(7/8):50-56.

(Hampton 2007a) VOC, Methanol, and Formaldehyde Emissions from the Drying of Hemlock, ESLP, and Douglas Fir Lumber. Report by M. R. Milota to Hampton Affiliates. March 23, 2007.

(Hampton 2007b) HAP Emissions from the Drying of Hemlock and Douglas-fir Lumber by NCASI Methods 98.01 and 105. Report to by M.R. Milota to Hampton Affiliates. May 22, 2007.

(Hampton 2007c) HAP Emissions by NCASI 98.01 and 105 from the Drying of Ponderosa Pine and White Wood Lumber, Report by M. R. Milota to Hampton Affiliates. July 25, 2007 (replaced report from July 18, 2007).

(Hampton 2012) Emissions from the drying of Douglas-fir lumber. Report by M.R. Milota to Hampton Affiliates. February 10, 2012.

(Hampton 2013) Emissions From the drying of ponderosa pine lumber. Report by M. R. Milota to Hampton Affiliates - Randle Division. March 7, 2013.

(IFA 2000) Small-scale Kiln Study Utilizing Ponderosa Pine, Lodgepole Pine, White Fir, and Douglas-fir. Report by M. R. Milota to Intermountain Forest Association. September 29, 2000.

(Milota 2003) Milota, M.R. 2003. HAP and VOC Emissions from White Fir Lumber Dried at High and Conventional Temperatures. Forest Prod. J. 53(3):60-64.

(Milota 2006) Milota M. R. 2006. Emissions from western hemlock lumber during drying. Compilation of hemlock dry kiln test results from July 1998 through February 2005.

(Milota 2008) Emission of Hazardous Air Pollutants from Lumber Drying. Milota, M.R. and P. Mosher. 2008. Forest Prod. J. 58(7/8):50-55.

(SP Centralia 2013) Total hydrocarbon and HAP emissions from the drying of Douglas-fir lumber. Report by M. R. Milota to Sierra Pacific Industries, Centralia, WA. May 23, 2013.

(SP Mt Vernon 2013) Dry Kiln Emission Testing for Filterable and Condensable Particulates. Report by M. R. Milota to Sierra Pacific Industries, Mt. Vernon, WA. May 29 - June 1, 2013.

(U of Idaho 1996) Small-scale Kiln Study of Method 25A Measurements of Volatile Organic Compound Emissions from Lumber Drying. Report by University of Idaho prepared for NCASI, March 28, 1996.

(USDA 1991) Dry Kiln Operator's Manual, USDA Forest Service, Forest Products Laboratory, Madison Wisconsin, Agriculture Handbook No. 188, Revised August 1991.

(Willamette 1988) Source Evaluation Report, Willamette Industries, Inc., Dry Kiln Particulate and VOC Emissions while Drying Hemlock. Nov. 16-20, 1998, Albany OR.

(Willamette 1988a) Source Evaluation Report, Willamette Industries, Inc., Dry Kiln Particulate and VOC Emissions while Drying Douglas Fir. Dec. 14-19, 1998, Albany OR.

(WDKA 1997) Changes in the VOC Emissions from Douglas-fir Lumber with Temperature and Humidity, Wood Dry Kilns Association, M. Milota and Jing Wu, Oregon State University, May 1997.

(WDKA 2001) VOC and HAP Emissions from Western Species. Western Dry Kiln Association, Michael Milota, Michael, May 2001.

Appendix A

Particulate Matter Test Summary

Lumber Dry Kiln Emission Tests Results for PM

The data does not indicate that wood species impacts the outcome of source tests.
the seperate runs are listed to demonstrate the range of results.

Total PM/PM10 (lb/mbf)	Front Half (lb/mbf)	Back Half (PM2.5) (lb/mbf)	Species	Maximum Dry Bulb Temperature (°F)	Method	Reference
0.0550	0.0055	0.0495	Hemlock	190	ODEQ M-7	Willamette 1998, R1
0.0460	0.0035	0.0425	Hemlock	190	ODEQ M-7	Willamette 1998, R2
0.0200	0.0052	0.0148	Douglas Fir	180	ODEQ M-7	Willamette 1998A, R1
0.0270	0.0093	0.0177	Douglas Fir	180	ODEQ M-7	Willamette 1998A, R2
0.0194	0.0030	0.0160	Hemlock	178	M5 and 202	SP Mt Vernon 2013
0.0198	0.0018	0.0180	Hemlock	178	M5 and 202	SP Mt Vernon 2013
0.0312	**0.0047**	**0.0264**				

Source Tests Used in this analysis.

Willamette 1998: Source Evaluation Report, Willamette Industries, Inc., Dry Kiln Particulate and VOC Emissions while Drying Hemlock. Nov. 16-20, 1998, Albany OR.
Willamette 1998A: Source Evaluation Report, Willamette Industries, Inc., Dry Kiln Particulate and VOC Emissions while Drying Douglas Fir. Dec. 14-19, 1998, Albany OR.
SP Mt Vernon: Sierra Pacific Industries Dry Kiln Emission Testing for Filterable and condensable Particulates, May 29 - June 1, 2013, Mt. Vernon WA.

Appendix B

Volatile Organic Compound (VOC) Test Summary

This spreadsheet compiles volatile organic compound (VOC) emission factors (EF) in units of pounds of propane per thousand board feet of lumber dried (lb/mbf). The EF are based on the average of available test data.

A summary of the EFs for each species of wood is included on this sheet. The sheets that follow present the original test data as well as the calculations for creating each EF.

Species	Number of Test runs	Test Temperature Range (°F)	VOC as Carbon (lb/mbf)	VOC as Propane (lb/mbf)
White Fir				
<= 220 F	7	180-220	0.380	0.465
> 220 F	3	225-240	0.537	0.657
Western Hemlock				
<= 220 F	9	180-215	0.215	0.263
> 220 F	14	225-235	0.267	0.326
Western Red Cedar				
<= 220 F	2	160	0.116	0.142
> 220 F	No test data. Cedar is not dried at high-temperature.			
Douglas Fir, heartwood and sapwood				
<= 220 F	21	160-220	0.608	0.744
> 220 F	1	235	1.206	1.476
Engelmann Spruce				
<= 220 F	No test data at conventional temperature. Recommend high-temperature data.			
> 220 F	1	235	0.110	0.135
Larch				
<= 220 F	No VOC test data. Recommend using hemlock values			
> 220 F	No VOC test data. Recommend using hemlock values			
Lodgepole Pine, White wood, ESLP				
<= 220 F	2	170-190	0.860	1.052
> 220 F	4	235-240	1.385	1.695
Ponderosa Pine				
<= 220 F	9	170-180	1.560	1.909
> 220 F	1	235	3.000	3.671
Western White Pine				
<= 220 F	1	170	2.260	2.766
> 220 F	No test data at high-temperature. Recommend conventional-temperature data.			

Volatile Organic Compound Emission Factors for Drying White Fir Lumber

White Fir VOC Emission Test Data

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[1] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
180	0.26	2x6	106.3 / 15	36.6	JUM 3-200	IFA 2002
180	0.27	2x6	113.6 / 15	43.2	JUM 3-200	IFA 2002
180	0.22	2x6	122.0 / 15	42.6	JUM 3-200	IFA 2002
180	0.25	2x6	133.2 / 15	46.9	JUM 3-200	IFA 2002
190	0.63	2x4	138.1 / 15	70	JUM VE-7	U of Idaho 1996
190	0.50	2x4	138.1 / 15	75	JUM VE-7	U of Idaho 1996
200	0.53	2x4	96.1 / 15	47	JUM VE-7	U of Idaho 1996
225	0.39	2x4	170 / 13	54	JUM VE-7	Fritz 2004
240	0.62	2x6	126.3 / 15	25	JUM 3-200	Milota 2003
240	0.6	2x6	119.0 / 15	25	JUM 3-200	Milota 2003

[1] Dry basis. Moisture content = (weight of water / weight wood) x 100

Conversion from Carbon to Propane 1.2238

Temp Range	*VOC as Carbon*	*VOC as Propane*
<= 220 F	0.380	0.465
> 220 F	0.537	0.657

Volatile Organic Compound Emission Factors for Drying Western Hemlock Lumber

These are used for the larch drying as well.

Western Hemlock VOC Emission Test Data[1]

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[2] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
180	0.73	2x6	126.6 / 15	66.5		Milota 2006
180	0.66	2x6	139.3 / 15	67.9		Milota 2006
180	0.6	2x6	127.8 / 15	65.7		Milota 2006
180	0.67	2x6	132.7 / 15	67		Milota 2006
180	0.17	2x4	114.8 / 15	45		Milota 2006
180	0.07	2x4	103.1 / 15	40.7		Milota 2006
180	0.12	2x4	98.0 / 15	37.5		Milota 2006
180	0.4	2x4	115.7 / 15	52.9		Milota 2006
180	0.236	2x4 or 2x6	93.5 / 17.5	no data	JUM VE-7	Milota 2008
180	0.142	2x4	102.3 / 14.7	49.5	JUM VE-7	Milota 2008
180	0.18	2x4	88.8 / 15	46.2	JUM VE-7	Hampton 03 2007
180	0.198	2x4	56.8 / 15	38.35		Milota 2006
180	0.122	2x4	51.1 / 15	35.75		Milota 2006
200	0.24	2x4	112.8 / 15	40	JUM VE-7	U of Idaho 1996
200	0.2	2x6	81.0 / 15	45.2		Milota 2006
200	0.15	2x6	73.7 / 15	36.5		Milota 2006
200	0.3	2x6	100.1 / 15	47.4		Milota 2006
200	0.204	2x4	76.0 / 15	30.25	JUM 3-200	Milota 2006
200	0.214	2x4 or 2x6	83.9 / 15.0	no data	JUM VE-7	Milota 2008
200	0.239	2x4 or 2x6	98.6 / 15.0	no data	JUM VE-7	Milota 2008
215	0.34	2x4	112.9 / 15	32.7		Milota 2006
215	0.34	2x4	119.7 / 15	38		Milota 2006
225	0.28	2x6	82 / 15	31.3		Milota 2006
225	0.27	2x6	77.4 / 15	28.6		Milota 2006
225	0.31	2x6	101.7 / 15	33.5		Milota 2006
235	0.247	2x4 or 2x6	81.6 / 15.0	no data	JUM VE-7	Milota 2008
235	0.226	2x4 or 2x6	76.2 / 15.0	no data	JUM VE-7	Milota 2008

[1] Western hemlock data used for Mountain Hemlock as well.

[2] Dry basis. Moisture content = (weight of water / weight wood) x 100

Conversion from Carbon to Propane 1.2238

Temp Range	*VOC as Carbon*	*VOC as Propane*
<= 220 F	0.215	0.263
> 220 F	0.267	0.326

Volatile Organic Compound Emission Factors for Western Red Cedar Lumber

Western Red Cedar VOC Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[1] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
160	0.096	1x4	33.3 / 15	21	JUM VE-7	U of Idaho 1996
160	0.136	1x4	44.9 / 15	18	JUM VE-7	U of Idaho 1996
	0.116					

[1] Dry basis. Moisture content = (weight of water / weight wood) x 100

VOC as Propane 0.142 lb/mbf as Propane

White Spruce VOC Emission Test Data

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[2] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
235	0.11	2x4 or 2x6	32.7 / 15	no data	JUM VE-7	Milota 2008

[1] In the absence of engelmann spruce test data, white spruce test data has been substituted. The two wood species are similar in that both are resinous softwood species in the scientific classification genus Picea.

[2] Dry basis. Moisture content = (weight of water / weight wood) x 100

VOC as Propane 0.135 lb/mbf as Propane

White Pine VOC Emission Test Data

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[2] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
170	2.26	1x4	117.4 / 15	44	JUM VE-7	U of Idaho 1996

[1] In the absence of engelmann spruce test data, white spruce test data has been substituted. The two wood species are similar in that both are resinous softwood species in the

[2] Dry basis. Moisture content = (weight of water / weight wood) x 100

VOC as Propane 2.766 lb/mbf as Propane

Volatile Organic Compound Emission Factors for Drying Douglas Fir Lumber

Douglas Fir VOC Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[1] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
160	0.510	2x6	37.3 / 15	23.5	JUM 3-200	IFA 2002
160	0.550	2x6	44.9 / 15	28.5	JUM 3-200	IFA 2002
160	0.450	2x6	40.3 / 15	27.1	JUM 3-200	IFA 2002
160	0.460	2x6	31.9 / 15	25.2	JUM 3-200	IFA 2002
160	0.759	2x6			JUM 3-200	WDKA 1997 (as propane)
170	0.650	2x4	79.9 / 15	40.5	JUM VE-7	Hampton 03 2007
170	0.241	2x4	56.9 / 15	27.5	JUM VE-7	Milota 2008
175	0.860	2x4	39.5 / 15.0	143	JUM VE-7	Columbia Vista 2015
175	0.185	2x4	32.5 / 12.5	17.8	JUM VE-7	SP Centralia 2013
175	0.210	2x4		53	JUM VE-7	U of Idaho 1996
180	0.644	2x6			JUM 3-200	WDKA 1997 (as propane)
180	0.776	2x6			JUM 3-200	WDKA 1997 (as propane)
180	0.693	2x6			JUM 3-200	WDKA 1997 (as propane)
180	0.942	2x4	38.9 / 15	63	JUM VE-7	U of Idaho 1996
180	0.669	2x4	44.9 / 15	42	JUM VE-7	U of Idaho 1996
180	0.210	2x4	56.3 / 15	27	JUM VE-7	U of Idaho 1996
180	0.575	2x4 or 2x6	43.7 / 15	no data	JUM VE-7	Milota 2008
180	0.390	4x4	29.8 / 19	67.5	JUM 3-200	Columbia Vista 2005
180	0.845	4x4	44.7 / 15	111	JUM VE-7	Columbia Vista 2010
180	0.342	2x4		21	JUM VE-7	U of Idaho 1996
180	0.400	2x6	38 / 15	60	JUM VE-7	Willamette 1998a
180	0.380	2x6	38 / 15	60	JUM VE-7	Willamette 1998a
200	0.660	2x4	69.3 / 15	21	JUM VE-7	Hampton 2012
200	0.528	2x6			JUM 3-200	WDKA 1997 (as propane)
200	0.707	2x4 or 2x6	64.3 / 15	no data	JUM VE-7	Milota 2008
200	0.879	2x4 or 2x6	59.5 / 15	no data	JUM VE-7	Milota 2008
220	1.300	2x4	73 / 12	46	JUM VE-7	Fritz 2004
220	1.200	2x4	73 / 15	46	JUM VE-7	Fritz 2004
235	1.206	2x4 or 2x6	47.7 / 15	19	JUM VE-7	Milota 2008

[1] Dry basis. Moisture content = (weight of water / weight wood) x 100.

Conversion from Carbon to Propane 1.2238

Temp Range	*VOC as Carbon*	*VOC as Propane*
<= 220 F	0.608	0.744
> 220 F	1.206	1.476

Volatile Organic Compound Emission Factors for Drying Lodgepole Pine Lumber

Results for ESLP and Whitewood were included with the Lodgepole Pine results

Lodgepole Pine VOC Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[1] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
170	0.33		61.8 / 15	34.63	JUM VE-7	Hampton 03 2007
190	1.39		119.2 / 15	45.25	JUM VE-7	Hampton 07 2007
235	2.31		106.8 / 15		JUM VE-7	Milota 2008
236	1.17	2x4	59.1 / 15	16.01	JUM 3-200	IFA 2002
238	0.87	2x4	56.9 / 15	16.01	JUM 3-200	IFA 2002
240	1.19	2x4	64.9 / 15	16.81	JUM 3-200	IFA 2002

[1] Dry basis. Moisture content = (weight of water / weight wood) x 100

Conversion from Carbon to Propane 1.2238

Temp Range	*VOC as Carbon*	*VOC as Propane*
<= 220 F	0.860	1.052
> 220 F	1.385	1.695

Volatile Organic Compound Emission Factors for Drying Ponderosa Pine Lumber

The database had 10 tests, but only one test over 200°F. Therefore, the P. Pine emission factor is based on the average of all the tests.

Ponderosa Pine VOC Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Method 25A VOC as Carbon (lb/mbf)	Lumber Dimensions	Moisture Content[1] (%) (Initial/Final)	Time to Final Moisture Content (hours)	Method 25A Analyzer	Reference
170	1.59	2x4	82.6 / 15	42	JUM VE-7	Hampton 07 2007, Milota 2008
170	1.795	1x4	112.8 / 15	29	JUM VE-7	U of Idaho 1996
170	1.925	1x4	88.7 / 15	28	JUM VE-7	U of Idaho 1996
176	1.29	2x10 & 2x12	107.1 / 12	55	JUM 3-200	IFG 2002
176	1.54	2x10 & 2x12	124.1 / 12	57	JUM 3-200	IFG 2002
176	1.40	2x10 & 2x12	114.8 / 12	58.5	JUM 3-200	IFG 2002
176	1.30	2x10 & 2x12	93.0 / 12	57.1	JUM 3-200	IFG 2002
180	1.48	2x4	103.9 / 15	39.4	JUM VE-7	Hampton 2013
180	1.72	2x4	122.0 / 15	43.6	JUM VE-7	Hampton 2013
235	3.00	2x4 or 2x6	89.1 / 15	19	JUM VE-7	Milota 2008

[1] Dry basis. Moisture content = (weight of water / weight wood) x 100

Conversion from Carbon to Propane 1.2238

Temp Range	*VOC as Carbon*	*VOC as Propane*
<= 220 F	1.560	1.91
> 220 F	3.00	3.67

Appendix C

Hazardous Air Pollutant (HAP) Test Summary

HAP Emission Factors for Lumber Drying

The emission factors are differentiated between drying temperatures less than or equal to 220°F and greater than 220°F.

A summary of the emission factors for each species is included on this sheet. The sheets that follow present the original test data as well as the calculations for creating each emission factor.

Species	Maximum Kiln Temperature (°F)	Total HAP (lb/mbf)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)
White Fir[1]	≤ 220°F	0.1798	0.1220	0.0028	0.0550	No test data is available. Recommend using western hemlock data.	
	> 220°F	0.4905	0.4195	0.0160	0.0550		
Western Hemlock	≤ 220°F	0.2096	0.0853	0.0015	0.1200	0.0012	0.0017
	> 220°F	0.2869	0.1958	0.0039	0.0840	0.0014	0.0019
Western Red Cedar	≤ 220°F	No test data is available. Recommend using lodgepole data.					
	> 220°F	Cedar is not dried at temperatures >220 °F					
Douglas Fir	≤ 220°F	0.0854	0.0436	0.0014	0.0392	0.0004	0.0008
	> 220°F	0.1903	0.1170	0.0043	0.0670	0.0008	0.0012
Engelmann Spruce	≤ 220°F	0.0631	0.0250	0.0013	0.0360	0.0003	0.0005
	> 220°F	0.1151	0.0780	0.0044	0.0310	0.0007	0.0010
Larch, no data use Hemlock	≤ 220°F	No test data is available. Recommend using Douglas fir data.					
	> 220°F	No test data is available. Recommend using Douglas fir data.					
Lodgepole Pine	≤ 220°F	0.1456	0.0588	0.0039	0.0780	0.0044	0.0005
	> 220°F	0.1569	0.0923	0.0056	0.0490	0.0043	0.0058
Ponderosa Pine	≤ 220°F	0.1364	0.0558	0.0034	0.0710	0.0027	0.0036
	> 220°F	0.1889	0.1440	0.0092	0.0280	0.0032	0.0045
Western White Pine, no data use P. Pine	≤ 220°F	No test data is available. Recommend using ponderosa pine data.					
	> 220°F	No test data is available. Recommend using ponderosa pine data.					

[1] White fir in this context refers to any one of several species of true fir grown in the West. The collection of timber commonly referred to as "white fir" includes the following species: white fir, grand fir, noble fir and subalpine fir.

HAP Emission Factors for Drying White Fir Lumber

White Fir HAP Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)	Reference
180	0.096	0.0022	no data	no data	no data	IFA 2000, WDKA 2001, Milota 2003
180	0.148	0.0034	no data	no data	no data	IFA 2000, WDKA 2001, Milota 2003
225	no data	no data	0.0550	no data	no data	Fritz 2004
240	0.42	0.0156	no data	no data	no data	Milota 2003
240	0.419	0.0163	no data	no data	no data	Milota 2003

[2] Dry basis. Moisture content = (weight of water / weight wood) x 100

White Fir HAP Emission Factors Based on Average of Test Data

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde[2] (lb/mbf)	Acrolein[2] (lb/mbf)
≤ 220°F	0.1220	0.0028	0.0550		
> 220°F	0.4195	0.0160			

Hazardous Air Pollutant Emission Factors for Western Hemlock Lumber

Western Hemlock HAP Emission Test Data by Drying Temperature[1]

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)	Reference
180	0.083	0.0013	no data	no data	no data	Hampton 05 2007
180	0.075	0.0014	0.078	0.002	0.0012	Hampton 05 2007
180	0.094	0.0015	0.141	0.0008	0.0012	Milota 2008
180	0.052	0.0007	no data	no data	no data	Hampton 03 2007
180	0.0312	0.00082	no data	no data	no data	Milota 2006
180	0.0304	0.00082	no data	no data	no data	Milota 2006
200	0.098	0.0015	no data	no data	no data	Milota 2006
200	0.175	0.0016	no data	no data	no data	Milota 2006
200	0.154	0.0018	no data	no data	no data	Milota 2006
200	0.044	0.0008	0.133	0.0008	0.0024	Milota 2008
200	0.077	0.0014	0.128	0.001	0.0011	Milota 2008
200	0.057	0.0014	no data	no data	no data	Milota 2006
215	0.138	0.0043	no data	no data	0.0027	Milota 2006
225	0.189	0.0035	no data	no data	no data	Milota 2006
225	0.167	0.0034	no data	no data	no data	Milota 2006
225	0.24	0.004	no data	no data	no data	Milota 2006
235	0.187	0.0045	0.084	0.0014	0.0019	Milota 2008

[1] Dry basis. Moisture content = (weight of water / weight wood) x 100

Western Hemlock HAP Emission Factors Based on Average of Test Data

Maximum Dry Bulb Temperature[1] (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)
< 220°F	0.0853	0.0015	0.1200	0.0012	0.0017
> 220°F	0.1958	0.0039	0.0840	0.0014	0.0019

Hazardous Air Pollutant Emission Factors for Drying Douglas Fir Lumber

Douglas Fir HAP Emission Test Data by Drying Temperature[1]

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)	Reference
160	0.025	0.0008	no data	no data	no data	IFA 2000, WDKA 2001
160	0.023	0.0008	no data	no data	no data	IFA 2000, WDKA 2001
160	0.026	0.0017	no data	no data	no data	IFA 2000, WDKA 2001
160	0.018	0.0011	no data	no data	no data	IFA 2000, WDKA 2001
170	0.015	0.0005	no data	no data	no data	Hampton 03 2007
170	0.026	0.0008	no data	no data	no data	Hampton 05 2007
170	0.024	0.0008	0.03	0.0004	0.0005	Hampton 05 2007
175	0.019	0.001	0.006	0.0001	0.0004	SP Centralia 2013
175	0.084	0.0016	0.042	0.0002	0.0008	Columbia Vista 2015
180	0.050	0.0023	0.050	0.0005	0.0009	Milota 2008
180	0.084	0.0019	0.061	0.0003	0.0007	Columbia Vista 2010
200	0.080	0.003	0.037	0.0006	0.0017	Hampton 2012
200	0.068	0.0018	0.043	0.0005	0.0009	Milota 2008
200	0.069	0.0019	0.071	0.0006	0.0004	Milota 2008
220	no data	no data	0.030	no data	no data	Fritz 2004
220	no data	no data	0.022	no data	no data	Fritz 2004
235	0.117	0.0043	0.067	0.0008	0.0012	Milota 2008

1 Dry basis. Moisture content = (weight of water / weight wood) x 100

Douglas Fir HAP Emission Factors Based on average of test data

Maximum Dry Bulb Temperature[1] (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)
≤ 220°F	0.0436	0.0014	0.0392	0.0004	0.0008
> 220°F	0.1170	0.0043	0.0670	0.0008	0.0012

Hazardous Air Pollutant Emission Factors for Engelmann Spruce Lumber

HAP Emission Test Data for Similar Species (White Spruce) by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)	Reference
180	0.025	0.0013	0.036	0.0003	0.0005	Milota 2008
235	0.078	0.0044	0.031	0.0007	0.001	Milota 2008

Engelmann Spruce HAP Emission Factors based on average of test data

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)
≤ 220°F	0.0250	0.0013	0.0360	0.0003	0.0005
> 220°F	0.0780	0.0044	0.0310	0.0007	0.0010

Hazardous Air Pollutant Emission Factors for Drying Lodgepole Pine Lumber
Includes results for ESLP and whitewood

Lodgepole Pine HAP Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)	Reference
170	0.03	0.0009	no data	no data	no data	Hampton 03 2007
190	0.090	0.0063	no data	no data	no data	Hampton 07 2007
190	0.074	0.0045	0.144	0.0044	0.0005	Hampton 07 2007
195	0.073	no data	0.012	no data	no data	Referenced in secondary document. Could not verify.
195	0.092	no data	no data	no data	no data	
195	0.064	no data	no data	no data	no data	
195	0.028	no data	no data	no data	no data	
195	0.02	no data	no data	no data	no data	
235	0.188	0.0101	0.049	0.0043	0.0058	Milota 2008
236	0.063	0.0041	no data	no data	no data	IFA 2000, WDKA 2001
237	0.062	0.0041	no data	no data	no data	IFA 2000, WDKA 2001
238	0.056	0.0039	no data	no data	no data	IFA 2000, WDKA 2001

Lodgepole Pine HAP Emission Factors Based on average test data

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)
≤ 220°F	0.0588	0.0039	0.0780	0.0044	0.0005
> 220°F	0.0923	0.0056	0.0490	0.0043	0.0058

Hazardous Air Pollutant Emission Factors for Drying Ponderosa Pine Lumber

Ponderosa Pine HAP Emission Test Data by Drying Temperature

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)	Reference
170	0.035	0.0027	0.042	0.0019	0.0017	Hampton 07 2007
176	0.05	0.0022	no data	no data	no data	IFA 2000, WDKA 2001
176	0.08	0.0036	no data	no data	no data	IFA 2000, WDKA 2001
180	0.058	0.005	0.100	0.0035	0.0055	Hampton 2013
235	0.144	0.0092	0.028	0.0032	0.0045	Milota 2008
170	0.04	0.0048	no data	no data	no data	Hampton 07 2007

Ponderosa Pine HAP Emission Factors Based on average test data

Maximum Dry Bulb Temperature (°F)	Methanol (lb/mbf)	Formaldehyde (lb/mbf)	Acetaldehyde (lb/mbf)	Propionaldehyde (lb/mbf)	Acrolein (lb/mbf)
≤ 220°F	0.0558	0.0034	0.0710	0.0027	0.0036
> 220°F	0.1440	0.0092	0.0280	0.0032	0.0045

APPENDIX C – PROCESSING FEE

PTC Processing Fee Calculation Worksheet

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**Idaho Forest Group LLC - Bennett -**
Address:	**171 Highway 95 North**
City:	**Grangeville**
State:	**Idaho Forest Group LLC - Bennett -**
Zip Code:	**83530**
Facility Contact:	**Jesse Short**
Title:	**Southern Division Manager**
AIRS No.:	**321113**

N	Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N
Y	Did this permit require engineering analysis? Y/N
N	Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	122.04	0	122.0
SO_2	0.00	106.27	-106.3
CO	0.61	0	0.6
PM10	1.12	0	1.1
VOC	36.00	0	36.0
Total:	159.77	106.27	**53.5**
Fee Due	**$ 5,000.00**		

Comments: