


Statement of Basis

**Permit to Construct No. P-2017.0001
Project ID 61833**

**Idaho Forest Group - Laclede
Laclede, Idaho**

Facility ID 017-00027

Final

**June 26, 2017
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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 ₂ e	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
ESP	electrostatic precipitator
GHG	greenhouse gases
gph	gallons per hour
gpm	gallons per minute
gr	grains (1 lb = 7,000 grains)
HAP	hazardous air pollutants
HHV	higher heating value
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
mbdft	thousand board feet
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
<i>Rules</i>	<i>Rules for the Control of Air Pollution in Idaho</i>
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
SOB	Statement of Basis
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
µg/m ³	micrograms per cubic meter

FACILITY INFORMATION

Description

The primary processes at Idaho Forest Group - Laclede are the sawmill, steam plant, dry kilns, and planer mill. Logs are debarked and then cut to dimension in the sawmill. Green lumber from the sawmill is dried in the dry kilns and then planed in the planer mill. Finally, the lumber is packaged and shipped by truck or rail. Bark from the debarker is shredded and transferred to the boiler for use as fuel. Shavings, chips, and sawdust are sold as by-products.

Permitting History

Refer to the current Tier I operating permit statement of basis for the permitting history.

Application Scope

This PTC is for a permit modification at an existing major facility.

The applicant has proposed to install a newer wood-fired boiler to replace the two existing hog fuel boilers and to modify fuel handling system to feed the single boiler. Because the facility becomes a minor facility after the project, the project is processed in according with the procedures for minor source permitting.

Facility-wide ambient impact analyses are performed to demonstrate that this project does not cause or significantly contribute to a violation of any applicable air quality standard in accordance with the State of Idaho Air Quality Modeling Guideline¹. As a result of the facility-wide ambient impact analyses, to ensure compliance with the NAAQS, new requirements are established for the dry kilns and material handling processes.

Application Chronology

January 3, 2017	DEQ received an application fee.
January 4, 2017	DEQ received an application.
February 2, 2017	DEQ determined that the application was complete.
March 20, 2017	DEQ made available the draft permit and statement of basis for peer and regional office review.
March 30, 2017	DEQ made available the draft permit and statement of basis for applicant review.
April 18, 2017	DEQ received the permit processing fee.
May 2 – June 1, 2017	DEQ provided a public comment period on the proposed action.
May 2 – June 16, 2017	DEQ provided a concurrent EPA and affected state review on the proposed action.
June 26, 2017	DEQ issued the final permit and statement of basis.

¹ Criteria pollutant thresholds in Table 2, State of Idaho Guideline for Performing Air Quality Impact Analyses, Doc ID AQ-011, September 2013.

TECHNICAL ANALYSIS

Emissions Units and Control Equipment

Table 1 EMISSIONS UNIT AND CONTROL EQUIPMENT INFORMATION¹

Source ID No.	Sources	Control Equipment
EU1	<u>Wellons wood-fired boiler</u> Manufacturer: Wellons Model: NB234 Boiler type: Two-cell pile-burning design Serial Number: B2329-0503 Manufacture Date: May 4, 2005 Heat input rating: 131 MMBtu/hr Max. production: 80,000 pounds steam per hour Fuel: hog fuel/biomass Fuel rate: ~ 13 tons/hr Fuel heat content: ~ 5,000 Btu/lb wet basis	<u>Multiclone</u> Manufacturer: Wellons Model: W144 Serial: B2329-1226 <u>Electrostatic Precipitator (ESP):</u> Manufacturer: Wellons Model: 2W-092-1422 Type: dry Number of fields: 2 Plate cleaning system: rapping PM ₁₀ control efficiency: 99%
NA	<u>Two dry kilns</u> Manufacturer: Wellons <u>Four dry kilns</u> Manufacturer: Ronan Total max. production, six dry kilns combined: 318,000 mbdft/yr, lumber dried.	None
NA	<u>Sawmill chip truck bin vent</u>	None
NA	<u>Sawdust truck bin vent</u>	None
NA	<u>Two planer shavings cyclones</u>	<u>Planer Shavings Cyclone Baghouses</u> Two baghouses, each control emissions from the respective planer cyclone Baghouse 1 Manufacturer: Western Pneumatics Model: W.P. Filter Type: Reverse Air Area of bags: ~6,000 sq. ft. Air to Cloth ratio: 8 to 1 Efficiency: 99% for PM and PM ₁₀ Baghouse 2 Manufacturer: Clarke Sheet Metal Model: Pneu-Aire Type: Reverse Air Area of bags: ~9,000 sq. ft. Air to Cloth Ratio: 8 to 1 Efficiency: 99% for PM and PM ₁₀
NA	<u>Planer chipper cyclone</u>	None
NA	<u>Shavings truck bin vent</u>	<u>Baghouse</u> Manufacturer: Clarke Sheet Metal Model: Pneu-Aire Type: Reverse Air Area of bags: ~400 sq.ft. Air to Cloth ratio: 8 to 1 PM ₁₀ control efficiency: 99%

Source ID No.	Sources	Control Equipment
NA	Fire water pump Manufacturer: Cummins Heat input rating: 1.54 MMBtu/hr (220 hp) Fuel: Diesel	None

¹ Refer to modeling memo for stack parameters.

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.

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

	PM ₁₀	PM _{2.5}	SO ₂	NO _x	VOCs	CO
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)
Point Sources						
WELLONS BOILER, EU1	---	---	---	---	---	---
BOILER #1	16.61	16.61	7.69	92.3	12.00	203
BOILER #2	16.01	16.01	7.41	88.9	11.56	306
LUMBER DRY KILNS, EU2	6.04	5.25	---	---	172	---
PLANER CHIPPER CYCLONE , EU3	1.571	0.786	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE, EU4	0.621	0.416	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE, EU5	0.621	0.416	---	---	---	---
SHAVINGS BIN VENT BAGHOUSE, EU6	0.0027	0.0018	---	---	---	---
FIRE WATER PUMP ENGINE	0.024	0.024	0.023	0.341	0.028	0.073
Point Source Total Emissions	41.5	39.5	15.1	181.3	195.5	509.1
Process Volume Sources						
DEBARKER, PF1	1.26	0.223	---	---	---	---
BARK HOG, PF2	0.0268	0.0047				
SAWMILL TRUCK BIN TOP VENT, PF3	0.0015	0.0002				
CHIP TRUCK BIN TOP VENT, PF4	0.0027	0.0004	---	---	---	---
SAWDUST BIN TRUCK LOADOUT, PF5	0.0030	0.0004	---	---	---	---
CHIP BIN TRUCK LOADOUT, PF6	0.0053	0.0008				
PLANER SHAVINGS BIN TRUCK LOADOUT, PF7	0.0043	0.0006				
PLANER CHIPS LOADOUT, PF7	0.0011	0.0002	---	---	---	---

	PM ₁₀	PM _{2.5}	SO ₂	NO _x	VOCs	CO
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)
HOG FUEL TRANSFER TO FUEL BIN	0.0009	0.0001	---	---	---	---
FUEL CONVEYED TO WELLONS	---	---	---	---	---	---
B1 FUEL CONVEYED TO BOILER	0.0021	0.0003	---	---	---	---
B2 FUEL LOADED TO FUEL PILE (FUGITIVE)	0.0043	0.0006	---	---	---	---
B2 FUEL TO HOPPER	0.0043	0.0006	---	---	---	---
SAWMILL SAWING, INDOOR	0.0917	0.0160	---	---	---	---
SAWDUST CONVEYING	0.0074	0.0011	---	---	---	---
PAVED ROADS (FUGITIVE)	0.324	0.079				
Plant-wide Total	43.24	39.84	15.1	181.54	195.5	509.1

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 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 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

	PM ₁₀	PM _{2.5}	SO ₂	NO _x	VOCs	CO
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)
Point Sources						
WELLONS BOILER, EU1	21.23	21.23	14.34	172	22.38	172
BOILER #1	---	---	---	---	---	---
BOILER #2	---	---	---	---	---	---
LUMBER DRY KILNS, EU2	6.04	5.25	---	---	172(225 ⁻¹)	---
PLANER CHIPPER CYCLONE , EU3	1.571	0.786	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE, EU4	0.621	0.416	---	---	---	---
PLANER SHAVINGS CYCLONE BAGHOUSE, EU5	0.621	0.416	---	---	---	---
SHAVINGS BIN VENT BAGHOUSE, EU6	0.003	0.002	---	---	---	---
FIRE WATER PUMP ENGINE	0.024	0.024	0.023	0.341	0.028	0.073
Point Source Total Emissions	30.1	28.1	14.3	172.3	194.3	172.1
Process Volume Sources						
DEBARKER, PF1	1.26	0.223	---	---	---	---
BARK HOG, PF2	0.027	0.0047				
SAWMILL TRUCK BIN TOP VENT, PF3	0.0015	0.0002				
CHIP TRUCK BIN TOP VENT, PF4	0.0027	0.0004	---	---	---	---
SAWDUST BIN TRUCK LOADOUT, PF5	0.0030	0.0004	---	---	---	---
CHIP BIN TRUCK LOADOUT, PF6	0.0053	0.0008				

	PM ₁₀	PM _{2.5}	SO ₂	NO _x	VOCs	CO
	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)	(ton/yr)
PLANER SHAVINGS BIN TRUCK LOADOUT, PF7	0.0043	0.0006				
PLANER CHIPS LOADOUT, PF7	0.0011	0.0002	---	---	---	---
HOG FUEL TRANSFER TO FUEL BIN	0.0009	0.0001	---	---	---	---
FUEL CONVEYED TO WELLONS	0.0043	0.0006	---	---	---	---
B1 FUEL CONVEYED TO BOILER	---	---	---	---	---	---
B2 FUEL LOADED TO FUEL PILE (FUGITIVE)	---	---	---	---	---	---
B2 FUEL TO HOPPER	---	---	---	---	---	---
SAWMILL SAWING, INDOOR	0.0917	0.0160	---	---	---	---
SAWDUST CONVEYING	0.0074	0.0011	---	---	---	---
PAVED ROADS (FUGITIVE)	0.324	0.079				
Plant-wide Total	31.84	28.44	14.3	172.3	194.3(247.3)	172.1

¹ permit limit

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 ₁₀	PM _{2.5}	SO ₂	NO _x	VOC	CO
	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Pre-Project Potential to Emit	43.24	39.84	15.1	181.5	195.5	509.1
Post Project Potential to Emit	31.84	28.44	14.3	172.3	194.3	172.1
Changes in Potential to Emit	-11.40	-11.40	-0.80	-9.20	-1.20	-337.00

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 (2017AAG21). The boiler replacement project has resulted in a reduction 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 hazardous air pollutants (HAP) 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 SUMMARY¹

Hazardous Air Pollutants	PTE (T/yr)
Hydrogen Chloride	12.62
Methanol	11.90
Formaldehyde	3.18
Acetaldehyde	7.60
Propionaldehyde	0.24
Acrolein	2.57
Acetophenone	1.84E-06
Benzene	2.41
bis(2-ethylhexyl)phthalate (DEHP)	2.70E-05
Bromomethane (methyl bromide)	0.0086
Carbon tetrachloride	0.026
Chlorine	0.453
Chlorobenzene	0.019
Chloroform	0.016
Chloromethane (Methyl Chloride)	0.013
1,2-Dichloroethane	0.017
Dichloromethane	0.166
1,2-Dichloropropane	0.019
2,4 Dinitrophenol	0.0001
Dioxins and Furans, TCDD	7.57E-07
Ethylbenzene	0.018
Hydrogen Chloride	12.62
Naphthalene	0.056
4-Nitrophenol	6.31E-05
Pentachlorophenol	2.93E-05
Phenol	0.029
Polycyclic Organic Matter (POM)	0.0017
Styrene	1.09
2,3,7,8-TCDD	4.93E-09
Toluene	0.528
1,1,1-Trichloroethane	0.018
Trichloroethene	0.017
Trichlorofluoromethane	0.024
2,4,6-Trichlorophenol	1.26E-05
Vinyl Chloride	0.010
o-Xylene	0.014
Antimony	0.0045

Hazardous Air Pollutants	PTE (T/yr)
Arsenic	0.013
Barium	0.040
Beryllium	0.0002
Cadmium	0.0024
Chromium, total	0.012
Chromium, hexavalent	0.0020
Cobalt	0.0037
Lead	0.028
Mercury	0.0005
Nickel	0.019
Selenium	0.0016
Totals	43.17

¹ Hydrogen chloride 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

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this will not cause or significantly contribute to a violation of any ambient air quality standard. Refer to the modeling memo in Appendix A for details.

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analyses submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Bonner County which is designated as attainment or unclassifiable for PM₁₀, PM_{2.5}, CO, NO₂, SO_x, and Ozone. Refer to 40 CFR 81.313 for additional information.

Facility Classification

The AIRS/AFS facility classification codes are as follows:

For THAPs (Total Hazardous Air Pollutants) Only:

- A = Use when any one HAP has actual or potential emissions ≥ 10 T/yr or if the aggregate of all HAPS (Total HAPS) has actual or potential emissions ≥ 25 T/yr.
- SM80 = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the permit sets limits ≥ 8 T/yr of a single HAP or ≥ 20 T/yr of THAP.
- SM = Use if a synthetic minor (potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable limitations) and the potential HAP emissions are limited to < 8 T/yr of a single HAP and/or < 20 T/yr of THAP.
- B = Use when the potential to emit without permit restrictions is below the 10 and 25 T/yr major source threshold

UNK = Class is unknown

For All Other Pollutants:

A = Actual or potential emissions of a pollutant are ≥ 100 T/yr.

SM80 = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are ≥ 80 T/yr.

SM = Use if a synthetic minor for the applicable pollutant (potential emissions fall below 100 T/yr if and only if the source complies with federally enforceable limitations) and potential emissions of the pollutant are < 80 T/yr.

B = Actual and potential emissions are < 100 T/yr without permit restrictions.

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 /PM _{2.5}	> 100	< 100	100	SM
SO ₂	< 100	< 100	100	B
NO _x	> 100	> 100	100	A
CO	> 100	> 100	100	A
VOC	> 100	> 100	100	A
HAP (single)	> 10	> 10	10	A
HAP (Total)	> 25	> 25	25	A

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201Permit to Construct Required

The permittee has requested that a PTC be issued to the facility for the boiler replacement project. 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 58.01.01.401Tier 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.

Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676Standards for New Sources

IDAPA 58.01.01.675-681 limit particulate emissions from fuel burning equipment. Section 676 provides limits for sources constructed after October 1, 1979, which are over 10 MMBtu/hr. The Wellons boiler is subject to the PM emission contained in IDAPA 58.01.01.676, which limits emissions to 0.080 gr/dscf @ 8% oxygen. This requirement is assured by Permit Conditions 2.3 and 2.6.

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

IDAPA 58.01.01.301Requirement 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, 10 tons per year for any one HAP, and 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 major facility, as defined in IDAPA 58.01.01.008.10.

This PTC will be incorporated into the Tier I operating permit in accordance with IDAPA 58.01.01.209.05.a.

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 CO have the potential to exceed major stationary source threshold of 250 T/yr. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a).

However, the proposed project will reduce the facility's CO PTE below 250 T/yr so that the facility will no longer be a PSD major facility. Based on EPA guidance, a permit modification that changes a facility to a non-major status does not constitute major modification under PSD regulations.

Detailed discussions can be found in Sections 2.3 and 2.4 of the application. EPA guidance can be found in Appendix B of the application (2017AAG21).

NSPS Applicability (40 CFR 60)

The Wellons wood-fired boiler is subject to 40 CFR 60 Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Detailed regulatory analysis can be found in Appendix E.1 of the SOB.

NESHAP Applicability (40 CFR 61)

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

MACT Applicability (40 CFR 63)

The Wellons wood-fired boiler is subject to 40 CFR 63 Subpart DDDDD - Industrial, Commercial, and Institutional Boilers and Process Heaters. Detailed regulatory analysis can be found in Appendix E.2 of the SOB.

Applicability

40 CFR 63, Subpart DDDDD applies to Wellons wood-fired boiler in accordance with 40 CFR 63.7485. The boiler is an existing affected source in accordance with 40 CFR 63.7490(d). The boiler falls into the subcategory of fuel cells designed to burn biomass/bio-based solid in accordance with 40 CFR 63.7499(g).

This permitting action does not alter the applicability status of other existing affected sources at the facility, such as 40 CFR 63 Subpart ZZZZ. Refer to Statement of Basis (SOB) for the current Tier I operating permit for details.

Permit Conditions Review

This section describes only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action.

PERMIT SCOPE

Permit Conditions 1.1 to 1.3 states the purposes of this permitting action, that those permit conditions that have been modified or revised by this permitting action are identified by the permit issue date citation located directly under the permit condition and on the right-hand margin, and that this PTC replaces Permit to Construct No. 017-00027, issued on June 26, 2001.

Table 1.1 lists the regulated sources in this PTC.

WELLONS WOOD-FIRED BOILER

Permit Conditions 2.1 and 2.2 describe the Wellons wood-fired boiler and its control.

Permit Condition 2.3

Permit Condition 2.3.1 establishes emissions limits of the boiler.

Because the facility-wide modeling analyses show that the total particulate matter impact of the facility is 87% of the 24-hr PM_{2.5} NAAQS and 81% of the 24-hr PM₁₀ NAAQS, the PM₁₀/PM_{2.5} limits are established to ensure compliance with the respective NAAQS. The limits in the permit are the modeled input rates in lb/hr based on 24-hr averaging period.

Because the facility-wide modeling analyses show that the total NO_x impact of the facility is 88% of the 1-hr NAAQS and 97% at the hotspot, the NO_x limit is established to ensure compliance with the NAAQS. The limit in the permit is the modeled input rate in lb/hr based on 1-hr averaging time period.

The facility is a PSD major source for CO. With the newer Wellons wood-fired boiler, the calculated CO emissions are 172.1 T/yr, and the facility will become a PSD minor source after this boiler replacement project. According to EPA's guidance, the project is processed following non-PSD major source rules and regulations. The pound per hour CO limit is set at 39.3 pounds per hour which assures compliance with the 172.1 ton per year emissions limit that is set to ensure that post project facility PTE stays below PSD major source threshold. The T/yr limit is for any consecutive 12 calendar month period. This pound per hour CO limit is more stringent than the CO limit in the Boiler MACT (i.e., 1,100 ppm by volume on a dry basis corrected to 3 percent oxygen in the Boiler MACT or 40 CFR 63 Subpart DDDDD).

$$172.1 \text{ T/yr} \times (2,000 \text{ lb/T}) / (8,760 \text{ hr/yr}) = 39.3 \text{ lb/hr}$$

Permit Condition 2.3.2 states that the boiler is subject to grain loading standard in accordance with IDAPA 58.01.01.676. As long as the boiler meets the PM_{2.5}/PM₁₀ emissions limits, the boiler meets this grain loading standard.

Permit Condition 2.4 states that the boiler is subject to the 20% opacity limit in accordance with IDAPA 58.01.01.625. No additional monitoring requirements are needed for compliance with the 20% opacity limit because the boiler is subject 10% opacity limit in the boiler MACT and is required to install continuous opacity monitoring system (COMS) in the boiler MACT.

Permit Conditions 2.5 and 2.6 are operating requirements that ensure boiler emissions continuously stay below the emissions limits in Permit Condition 2.3 because the boiler emissions were estimated using the boiler design heating rate or steam rate and that particulate emissions are controlled by a multicone and ESP in series. No specific ESP operating requirements are imposed here because the boiler is required to comply with requirements related to ESP in the boiler MACT.

Permit Condition 2.7 is a steam rate monitoring requirement.

Permit Condition 2.8 requires initial performance testing for NO_x, CO, PM_{2.5}/PM₁₀, and PM to demonstrate compliance with the respective emissions limits in Permit Condition 2.3.

Permit Condition 2.9 specifies additional source test requirements, such as monitoring steaming rate during the performance test every 15 minutes.

Permit Condition 2.10 specifies a subsequent performance test frequency to ensure continuous compliance with the emissions limits in Permit Condition 2.3.

Permit Conditions 2.11 and 2.12 state that the boiler is subject to boiler MACT (40 CFR 63 Subpart DDDDD) and NSPS Subpart Db. Because the facility has a Tier I operating permit that will include all applicable requirements in the boiler MACT and NSPS Subpart Db, this PTC will only include the high level citations.

DRY KILNS

Permit Conditions 3.1 and 3.2 describe the dry kilns and the control.

Permit Condition 3.3 states the permittee shall comply with the 20% visible emission requirement.

Permit Condition 3.4 establishes the emissions limits of the dry kilns. Because the facility-wide modeling analyses show that the total particulate matter impact of the facility is 87% of the 24-hr PM_{2.5} NAAQS and 81% of the 24-hr PM₁₀ NAAQS, the PM₁₀/PM_{2.5} limits are established to ensure compliance with the respective

NAAQS. The limits in the permit in lb/hr were calculated as the following.

For PM₁₀: (318,000 mbdft/yr) * (PM₁₀ EF of 0.038 lbs/mbdft) / (365 day/yr) / (24 hr/day) = 1.38 lb/hr.

For PM_{2.5}: (318,000 mbdft/yr) * (PM_{2.5} EF of 0.033 lbs/mbdft) / (365 day/yr) / (24 hr/day) = 1.20 lb/hr.

The above emissions were distributed evenly among the vents of the dry kilns and then modeled.

Based on current lumber species dried and the percentage of each lumber species dried, the VOC emissions are 172 T/yr. VOC emissions vary when the aforementioned two factors change. Therefore a VOC emissions limit of 225 T/yr is established to keep the facility VOC PTE below major source threshold to keep the facility as PSD minor source.

Permit Condition 3.5 establishes total kilns throughput limit of 318,000 mbdft/yr that ensures kilns emissions stay below the emissions limits in Permit Condition 3.4.

Permit Condition 3.6 is the kiln throughput monitoring requirement to demonstrate compliance with dry kilns production limit and ultimately, compliance with the emissions limits in Permit Condition 3.4.

Permit Condition 3.7 is a monitoring requirement to ensure VOC emissions from dry kilns below the limit.

SAWMILL, PLANER MILL, AND MATERIAL HANDLING

Permit Condition 4.1 describes the sawmill, planer mill, and material handling.

Permit Condition 4.2 and Table 4.1 describe the control of the sawmill, planer mill, and material handling.

Permit Condition 4.3 states that the permittee shall comply with the visible emission requirements.

Emissions limits

Though the facility-wide modeling analyses show that the total particulate matter impact of the facility is 87% of the 24-hr PM_{2.5} NAAQS and 81% of the 24-hr PM₁₀ NAAQS, according to DEQ's modeler, the impact to NAAQS from the emissions of the sawmill, planer mill, and their material handling is low. Therefore no specific emissions limits are included in the permit as long as the sawmill, planer mill, and their material handling are operated as described in the application. Permit Conditions 4.4 and 4.5 have imposed the operating requirements.

Permit Condition 4.4 states that the permittee shall comply with dry kilns maximum throughput limit because emissions from material handling are calculated by multiplying kilns throughput, residuals coefficients related to kilns lumber production from IFG records, and the respective emissions factors. Kilns production limit inherently limits the shaving, chip, and sawdust throughputs.

Permit Condition 4.5 states that for each of the two planer shavings cyclones, the permittee shall install and operate a baghouse to control particulate emissions from each cyclone.

Permit Condition 4.6 is the standard language taken from DEQ's internal guidance (2008AAF202) for baghouses.

Permit Condition 4.8 is a throughput monitoring requirement.

FIRE WATER PUMP

Permit Conditions 5.1 and 5.2 describe the fire water pump and its control.

Permit Condition 5.3 states that the permittee shall comply with all applicable provisions of 40 CFR 63 Subpart ZZZZ for the fire water pump. Because the facility's Tier I operating permit has included applicable requirements in 40 CFR 63 Subpart ZZZZ for the water fire pump, this PTC will only include the high level citations.

GENERAL PROVISIONS

General provisions are updated using the current PTC template.

PUBLIC REVIEW

Public Comment Period

A public comment period was made available to the public in accordance with IDAPA 58.01.01.209.05.a. EPA and affected state review occurred concurrently with the public comment period. During this time, comments were not submitted in response to DEQ's proposed action. EPA and affected states did not submit comments during their 45-day review period. Refer to the chronology dates for public comment period and EPA and affected state review.

APPENDIX A – EMISSIONS INVENTORIES

IDAHO FOREST GROUP
LACLEDE, IDAHO
Emission Inventory/Calculations

Proposed PTE with Wellons Boiler

	PM10 (ton/yr)	PM2.5 (ton/yr)	SO ₂ (ton/yr)	NO _x (ton/yr)	VOCs (ton/yr)	CO (ton/yr)	HAPS (ton/yr)
Point Sources							
WELLONS, EU1	21.23	21.23	14.34	172	22.38	172	24.08
BOILER #1	—	—	—	—	—	—	—
BOILER #2	—	—	—	—	—	—	—
LUMBER DRY KILNS, EU2	6.04	5.25	—	—	172	—	19.22
PLANER CHIPPER CYCLONE, EU3	1.571	0.786	—	—	—	—	—
PLANER SHAVINGS CYCLONE BAGHOUSE, EU4	0.621	0.416	—	—	—	—	—
PLANER SHAVINGS CYCLONE BAGHOUSE, EU5	0.621	0.416	—	—	—	—	—
SHAVINGS BIN VENT BAGHOUSE, EU6	0.003	0.002	—	—	—	—	—
EMERGENCY FIRE PUMP ENGINE	2.42E-02	2.42E-02	2.26E-02	3.41E-01	2.77E-02	7.35E-02	2.56E-02
Point Source Total Emissions	30.1	28.1	14.4	172	194.3	172	43.3
Process Fugitive Sources							
DEBARKER, PF1	1.26	0.223	—	—	—	—	—
BARK HOG, PF2	0.027	0.0047	—	—	—	—	—
SAWMILL TRUCK BIN TOP VENT, PF3	0.0015	0.0002	—	—	—	—	—
CHIP TRUCK BIN TOP VENT, PF4	0.0027	0.0004	—	—	—	—	—
SAWDUST BIN TRUCK LOADOUT, PF5	0.0030	0.0004	—	—	—	—	—
CHIP BIN TRUCK LOADOUT, PF6	0.0053	0.0008	—	—	—	—	—
PLANER SHAVINGS BIN TRUCK LOADOUT, PF7	0.0043	0.0006	—	—	—	—	—
PLANER CHIPS LOADOUT, PF7	0.0011	0.0002	—	—	—	—	—
Fugitive Sources							
HOG FUEL TRANSFER TO FUEL BIN	0.0009	0.0001	—	—	—	—	—
FUEL CONVEYED TO WELLONS	0.0043	0.0006	—	—	—	—	—
B1 FUEL CONVEYED TO BOILER	—	—	—	—	—	—	—
B2 FUEL LOADED TO FUEL PILE	—	—	—	—	—	—	—
B2 FUEL TO HOPPER	—	—	—	—	—	—	—
SAWMILL SAWING, INDOOR	0.0917	0.0160	—	—	—	—	—
SAWDUST CONVEYING	0.0074	0.0011	—	—	—	—	—
PAVED ROADS	0.324	0.079	—	—	—	—	—
Fugitive Totals	1.73	0.33	0.00	0.00	0.00	0.00	0.00

Plantwide Total

31.84 28.45 14.4 172.5 194.3 172.2

Currently Permitted PTE

PM10 (ton/yr)	PM2.5 (ton/yr)	SO ₂ (ton/yr)	NO _x (ton/yr)	VOCs (ton/yr)	CO (ton/yr)
—	—	—	—	—	—
16.61	16.61	7.69	92.3	12.00	203
16.01	16.01	7.41	88.9	11.56	306
6.04	5.25	—	—	172	—
1.571	0.786	—	—	—	—
0.621	0.416	—	—	—	—
0.621	0.416	—	—	—	—
0.0027	0.0018	—	—	—	—
2.42E-02	2.42E-02	2.26E-02	3.41E-01	2.77E-02	7.35E-02
41.5	39.5	15.1	182	195.5	509
1.26	0.223	—	—	—	—
0.0268	0.0047	—	—	—	—
0.0015	0.0002	—	—	—	—
0.0027	0.0004	—	—	—	—
0.0030	0.0004	—	—	—	—
0.0053	0.0008	—	—	—	—
0.0043	0.0006	—	—	—	—
0.0011	0.0002	—	—	—	—
0.0009	0.0001	—	—	—	—
—	—	—	—	—	—
0.0021	0.0003	—	—	—	—
0.0043	0.0006	—	—	—	—
0.0043	0.0006	—	—	—	—
0.0917	0.0160	—	—	—	—
0.0074	0.0011	—	—	—	—
0.324	0.079	—	—	—	—
1.74	0.33	0.00	0.00	0.00	0.00

43.24 39.84 15.1 181.6 195 509.1

IDAHO FOREST GROUP
LACLEDE, IDAHO
Emission Inventory/Calculations

Proposed PTE with Wellons Boiler

Point Sources
WELLONS, EU1
BOILER #1
BOILER #2
LUMBER DRY KILNS, EU2
PLANER CHIPPER CYCLONE , EU3
PLANER SHAVINGS CYCLONE BAGHOUSE, EU4
PLANER SHAVINGS CYCLONE BAGHOUSE, EU5
SHAVINGS BIN VENT BAGHOUSE, EU6
EMERGENCY FIRE PUMP
Point Source Total Emissions
Process Fugitive Sources
DEBARKER, PF1
BARK HOG, PF2
SAWMILL TRUCK BIN TOP VENT, PF3
CHIP TRUCK BIN TOP VENT, PF4
SAWDUST BIN TRUCK LOADOUT, PF5
CHIP BIN TRUCK LOADOUT, PF6
PLANER SHAVINGS BIN TRUCK LOADOUT, PF7
PLANER CHIPS LOADOUT, PF7
Fugitive Sources
HOG FUEL TRANSFER TO FUEL BIN
FUEL CONVEYED TO WELLONS
B1 FUEL CONVEYED TO BOILER
B2 FUEL LOADED TO FUEL PILE
B2 FUEL TO HOPPER
SAWMILL SAWING, INDOOR
SAWDUST CONVEYING
PAVED ROADS
Fugitive Totals

PM10 (lb/hr)	PM2.5 (lb/hr)	SO ₂ (lb/hr)	NO _x (lb/hr)	VOCs (lb/hr)	CO (lb/hr)	HAPS (lb/hr)
4.85	4.85	3.28	39.3	5.11	39.30	5.50
—	—	—	—	—	—	—
—	—	—	—	—	—	—
1.38	1.20	—	—	39.2	—	4.39
0.420	0.210	—	—	—	—	—
0.166	0.111	—	—	—	—	—
0.166	0.111	—	—	—	—	—
7.23E-04	4.84E-04	—	—	—	—	—
0.484	0.484	0.451	6.82	0.553	1.470	5.84E-03
7.5	7.0	3.7	46	44.9	40.8	9.9
3.36E-01	5.95E-02	—	—	—	—	—
7.15E-03	1.27E-03	—	—	—	—	—
3.95E-04	5.64E-05	—	—	—	—	—
7.09E-04	1.01E-04	—	—	—	—	—
7.90E-04	1.13E-04	—	—	—	—	—
1.42E-03	2.03E-04	—	—	—	—	—
1.16E-03	1.66E-04	—	—	—	—	—
2.94E-04	4.20E-05	—	—	—	—	—
2.27E-04	3.25E-05	—	—	—	—	—
1.14E-03	1.62E-04	—	—	—	—	—
—	—	—	—	—	—	—
—	—	—	—	—	—	—
—	—	—	—	—	—	—
2.45E-02	4.28E-03	—	—	—	—	—
1.97E-03	2.82E-04	—	—	—	—	—
7.39E-02	1.81E-02	—	—	—	—	—
0.45	0.08	0.00	0.00	0.00	0.00	0.00

Plantwide Total

7.91 7.05 3.7 46.1 44.9 40.8

Currently Permitted PTE

PM10 (lb/hr)	PM2.5 (lb/hr)	SO ₂ (lb/hr)	NO _x (lb/hr)	VOCs (lb/hr)	CO (lb/hr)
—	—	—	—	—	—
3.79	3.79	1.76	21.1	2.74	46.0
3.66	3.66	1.69	20.3	2.64	70.0
1.38	1.20	—	—	39.2	—
0.420	0.210	—	—	—	—
0.166	0.111	—	—	—	—
0.166	0.111	—	—	—	—
7.23E-04	4.84E-04	—	—	—	—
0.484	0.484	0.451	6.82	0.553	1.47
10.1	9.6	3.9	48	45.2	117
3.36E-01	5.95E-02	—	—	—	—
7.15E-03	1.27E-03	—	—	—	—
3.95E-04	5.64E-05	—	—	—	—
7.09E-04	1.01E-04	—	—	—	—
7.90E-04	1.13E-04	—	—	—	—
1.42E-03	2.03E-04	—	—	—	—
1.16E-03	1.66E-04	—	—	—	—
2.94E-04	4.20E-05	—	—	—	—
2.27E-04	3.25E-05	—	—	—	—
1.14E-03	1.62E-04	—	—	—	—
5.69E-04	8.12E-05	—	—	—	—
1.14E-03	1.62E-04	—	—	—	—
1.14E-03	1.62E-04	—	—	—	—
2.45E-02	4.28E-03	—	—	—	—
1.97E-03	2.82E-04	—	—	—	—
7.39E-02	1.81E-02	—	—	—	—
0.45	0.08	0.00	0.00	0.00	0.00

10.52 9.65 3.9 48.2 45.2 117.5

IDAHO FOREST GROUP, LACLEDE
Production Information for Emissions Calculations

Lumber Production

Daily Production is based on 6 days/wk for sawmill and planer

Sawmill	318,000	mbdft/year	1,019	mbdft/day
Dry Kilns	318,000	mbdft/year	871	mbdft/day
Planer	318,000	mbdft/year	1,019	mbdft/day
Logs Used	1,144,800	tons/yr	3,669	tons/day
Sawmill Hours	7,488	6 days/week, 52 weeks		
Planer Hours	7,488	6 days/week, 52 weeks		
Kiln Hours	8,760	hours/year, potential		

Steam Plant Information

Wellons Hours	8,760	hours/year, potential
Wellons Steam	700,800	thousand pounds/yr, potential
Weollons heat input	1,147,560	MMBtu/yr, potential
Boiler #1 Hours	8,760	hours/year, potential
Boiler #1 Steam	483,552	thousand pounds/yr, based on permit
Boiler #1 heat input	615,215	MMBtu/yr, based on permit
Boiler #2 Hours	8,760	hours/year, potential
Boiler #2 Steam	438,000	thousand pounds/yr, based on permit
Boiler #2 heat input	592,964	MMBtu/yr, based on permit

Residuals Production, Based on IFG Records

	BDT/yr	BDT/day	Estimation Factor	
Sawmill Chips	151,698	486	0.477	BDT/mbdft sawmill
Sawdust	84,476	271	0.266	BDT/mbdft sawmill
Hog Bark	48,654	156	0.043	BDT/tons logs
Planer Chips	15,710	50	0.049	BDT/mbdft planer
Shavings	62,087	199	0.195	BDT/mbdft planer

	Moisture Content	Green Wt. ton/year	ton/day
Sawmill Chips	50%	303,397	972
Sawdust	50%	168,953	542
Hog Bark	50%	97,308	312
Planer Chips	15%	18,482	59
Shavings	15%	73,044	234

Wellons Fuel Cell Boiler with ESP

WELLONS, EU1

Boiler Production	8,760 Hours/Year	Max Potential Hours
	80,000 lb steam/hour	Peak 1-hour steam rate
	131.00 mmBtu/hr, design	Design heat input
	700,800 klb steam/yr	PTE annual steam production
	1,147,560 mmBtu/yr	PTE annual heat input

CRITERIA POLLUTANTS

PM (controlled):

PM/PM10/PM2.5, MACT Limit

Emission Factor:	0.02 lb/mmBtu	Boiler MACT Limit for Fuel Cell Boilers
Emissions:	11.48 tons/year	Front half PM only
	2.62 lbs/hr	

PM/PM10/PM2.5, Condensable Back Half

Emission Factor:	0.017 lb/mmBtu	(AP-42 TABLE 1.6-1, Rev 9/03)
Emissions:	9.75 tons/year	
	2.23 lbs/hr	

PM/PM10/PM2.5, Total

Emissions:	21.23 tons/year
	4.847 lbs/hr

Sulfur Dioxide:

Emission Factor:	0.025 lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	14.34 tons/year	
	3.28 lbs/hr	

Nitrogen Oxides (NOx)

Emission Factor:	0.30 lb/mmBtu	Industry standard NOx estimate.
Emissions:	172.13 tons/year	Source test was 0.166 lb/MMBtu
	39.30 lbs/hr	

Volatile Organic Compounds (VOC)

Emission Factor:	0.039 lb/mmBtu	(AP-42 TABLE 1.6-3, Rev 9/03)
Emissions:	22.38 tons/year	TOC
	5.11 lbs/hr	

Carbon Monoxide (CO)

Emissions:	0.30 lb/mmBtu	Industry Standard CO Estimate
	172.13 tons/year	Source test was 0.135 lb/MMBtu
	39.30 lbs/hr	

Lead (Pb)

Emission Factor:	4.80E-05 lb/mmBtu	(AP-42 TABLE 1.6-4, Rev 9/03)
Emissions:	2.75E-02 tons/year	Estimated Actual
	6.29E-03 lbs/hr	
	4.68 lb/month (744 hrs)	

MACT Emission Limits, based on January 31, 2013 version of Boiler MACT. Effective Jan. 31, 2017 (extended)

Particulate Matter, filterable

Emissions:	0.020 lb/mmBtu heat input	Table 2 to Subpart DDDDD of Part 63
	11.48 tons/year	12. Fuel Cell boilers/biomass
	2.62 lbs/hr	

Carbon Monoxide (CO)

Emissions:	910 ppm @ 3% oxygen	Table 2 to Subpart DDDDD of Part 63
	1,257,600 dscf/hr, flue gas @ 0% oxygen	Based on F-Factor for wood bark
	1,468,371 dscf/hr, flue gas @ 3% oxygen	Adjusted to 3% oxygen
	3,870 lbmol/hr, flue gas @ 3% oxygen	379.4 dscf/lbmol At 60°F and 1 atm.
	3.52 lbmol/hr CO	1500 ppm CO
	98.6 lb/hr CO	M.W. = 28.01 lb/lbmol
	432 lpy CO	

Greenhouse Gas Calculations

Boiler Heat Input 1,147,560 MMBtu/year

Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)

Emission Factor:	206.36 lb/mmBtu	EPA Mandatory Reporting Rule
Emissions:	118,405 tpy CO2	

Methane

Emission Factor:	1.58E-02 lb/mmBtu	EPA Mandatory Reporting Rule
Emissions:	18,177 lb/yr	
	9.09 tpy	
	206.56 metric tons CO2e, GWP = 25	

Nitrous Oxide

Emission Factor:	7.92E-03 lb/mmBtu	EPA Mandatory Reporting Rule
Emissions:	9,089 lb/yr	
	4.54 tpy	
	1,231.10 metric tons CO2e, GWP = 298	

Total 118,419 tpy GHG

Total GHG Emissions (excluding biogenic CO2), point sources

Carbon Dioxide	0
Methane	206.56
Nitrous Oxide	1,231.10
	1,438 metric tons CO2e

BOILER #1 PERRY SMITH ABCO- SPREADER-STOKER w/ESP**BOILER #1**

Boiler Production	8,760 Hours/Year	Max Potential Hour
	55,200 1000 lb steam/hour	Permit Condition 4.7
	70.23 mmBtu/hr, design	Permit Table 2.1
	615,215 mmBtu/yr	

CRITERIA POLLUTANTS

PM (controlled):		
PM/PM10/PM2.5, Permit Limits		
Emissions:	0.20 gr/dscf @ 8% oxygen	Permit Condition 4.3
	96 tons/year	Permit Condition 4.4
	22 lbs/hr	Permit Condition 4.4
PM/PM10/PM2.5, MACT Limit		
Emission Factor:	0.037 lb/mmBtu	Boiler MACT Limit for Stoker Boilers
Emissions:	11.38 tons/year	Front half PM only
	2.60 lbs/hr	
PM/PM10/PM2.5, Condensable Back Half		
Emission Factor:	0.017 lb/mmBtu	(AP-42 TABLE 1.6-1, Rev 9/03)
Emissions:	5.23 tons/year	
	1.19 lbs/hr	
PM/PM10/PM2.5, Total		
Emissions:	16.61 tons/year	
	3.79 lbs/hr	
Sulfur Dioxide:		
Emission Factor:	0.025 lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)
Emissions:	7.69 tons/year	
	1.76 lbs/hr	
Nitrogen Oxides (NOx)		
Emission Factor:	0.30 lb/mmBtu	BACT at the time the boiler was built.
Emissions:	92.28 tons/year	Don't have boiler source test.
	21.07 lbs/hr	
Volatile Organic Compounds (VOC)		
Emission Factor:	0.039 lb/mmBtu	(AP-42 TABLE 1.6-3, Rev 9/03)
Emissions:	12.00 tons/year	TOC
	2.74 lbs/hr	
Carbon Monoxide (CO)		
Emissions:	No Factor	Based on permit limits
	203 tons/year	Permit Condition 4.5
	46 lbs/hr	Permit Condition 4.5
Lead (Pb)		
Emission Factor:	4.80E-05 lb/mmBtu	(AP-42 TABLE 1.6-4, Rev 9/03)
Emissions:	1.48E-02 tons/year	Estimated Actual
	3.37E-03 lbs/hr	

MACT Emission Limits, based on January 31, 2013 version of Boiler MACT. Effective Jan. 1, 2017

Particulate Matter, filterable		
Emissions:	0.037 lb/mmBtu heat input	Table 2 to Subpart DDDDD of Part 63
	11.38 tons/year	7. Stokers designed to burn wet biomass fuel
	2.60 lbs/hr	
Carbon Monoxide (CO)		
Emissions:	1500 ppm @ 3% oxygen	Table 2 to Subpart DDDDD of Part 63
	674,208 dscf/hr, flue gas @ 0% oxygen	Based on F-Factor for wood bark
	787,204 dscf/hr, flue gas @ 3% oxygen	Adjusted to 3% oxygen
	2,075 lbmol/hr, flue gas @ 3% oxygen	379.4 dscf/lbmol At 60°F and 1 atm.
	3.11 lbmol/hr CO	1500 ppm CO
	87.2 lb/hr CO	M.W. = 28.01 lb/lbmol
	382 tpy CO	

Greenhouse Gas Calculations

Boiler Heat Input	615,215 MMBtu/year	
Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)		
Emission Factor:	206.36 lb/mmBtu	EPA Mandatory Reporting Rule
Emissions:	63,478 tpy CO2	
Methane		
Emission Factor:	1.58E-02 lb/mmBtu	EPA Mandatory Reporting Rule
Emissions:	9,745 lb/yr	
	4.87 tpy	
	110.74 metric tons CO2e, GWP = 25	
Nitrous Oxide		
Emission Factor:	7.92E-03 lb/mmBtu	EPA Mandatory Reporting Rule
Emissions:	4,873 lb/yr	
	2.44 tpy	
	660.00 metric tons CO2e, GWP = 298	
Total	63,485 tpy GHG	
Total GHG Emissions (excluding biogenic CO2), point sources		
Carbon Dioxide	0	
Methane	110.74	
Nitrous Oxide	660.00	
	771 metric tons CO2e	

BOILER #2 KIPPER AND SONS - SPREADER-STOKER w/ESP

BOILER #2	Boiler Production	8,760 Hours/Year	Max Potential House
		50,000 1000 lb steam/hour	Permit Condition 5.7
		67.69 mmBtu/hr, design	Permit Table 2.1
		592,964 mmBtu/yr	
CRITERIA POLLUTANTS			
PM (controlled):			
PM/PM10/PM2.5, Permit Limits			
Emissions:	0.080 gr/dscf @ 8% oxygen	Permit Condition 5.3	
	53 tons/year	Permit Condition 5.4	
	12 lbs/hr	Permit Condition 5.4	
PM/PM10/PM2.5, MACT Limit			
Emission Factor:	0.037 lb/mmBtu	Boiler MACT Limit for Stoker Boilers	
Emissions:	10.97 tons/year	Front half PM only	
	2.50 lbs/hr		
PM/PM10/PM2.5, Condensable Back Half			
Emission Factor:	0.017 lb/mmBtu	(AP-42 TABLE 1.6-1, Rev 9/03)	
Emissions:	5.04 tons/year		
	1.15 lbs/hr		
PM/PM10/PM2.5, Total			
Emissions:	16.01 tons/year		
	3.66 lbs/hr		
Sulfur Dioxide:			
Emission Factor:	0.025 lb/mmBtu	(AP-42 TABLE 1.6-2, Rev 9/03)	
Emissions:	7.41 tons/year		
	1.69 lbs/hr		
Nitrogen Oxides (NOx)			
Emission Factor:	0.30 lb/mmBtu	BACT at the time the boiler was built.	
Emissions:	88.94 tons/year	Don't have boiler source test.	
	20.31 lbs/hr		
Volatile Organic Compounds (VOC)			
Emission Factor:	0.039 lb/mmBtu	(AP-42 TABLE 1.6-3, Rev 9/03)	
Emissions:	11.56 tons/year	TOC	
	2.64 lbs/hr		
Carbon Monoxide (CO)			
Emissions:	No Factor	Based on permit limits	
	306 tons/year	Permit Condition 5.5	
	70 lbs/hr	Permit Condition 5.5	
Lead (Pb)			
Emission Factor:	4.80E-05 lb/mmBtu	(AP-42 TABLE 1.6-4, Rev 9/03)	
Emissions:	1.42E-02 tons/year	Estimated Actual	
	3.25E-03 lbs/hr		

MACT Emission Limits, based on January 31, 2013 version of Boiler MACT. Effective Jan. 1, 2017

Particulate Matter, filterable			
Emissions:	0.037 lb/mmBtu heat input	Table 2 to Subpart DDDDD of Part 63	
	10.97 tons/year	7. Stokers designed to burn wet biomass fuel	
	2.50 lbs/hr		
Carbon Monoxide (CO)			
Emissions:	1500 ppm @ 3% oxygen	Table 2 to Subpart DDDDD of Part 63	
	649,824 dscf/hr, flue gas @ 0% oxygen	Based on F-Factor for wood bark	
	758,733 dscf/hr, flue gas @ 3% oxygen	Adjusted to 3% oxygen	
	2,000 lbmol/hr, flue gas @ 3% oxygen	379.4 dscf/lbmol At 60°F and 1 atm.	
	3.00 lbmol/hr CO	1500 ppm CO	
	84.0 lb/hr CO	M.W. = 28.01 lb/lbmol	
	368 tpy CO		
Greenhouse Gas Calculations			
Boiler Heat Input	592,964 MMBtu/year		
Carbon Dioxide (CO2) (not actually a greenhouse gas when emitted from biomass burning)			
Emission Factor:	206.36 lb/mmBtu	EPA Mandatory Reporting Rule	
Emissions:	61,182 tpy CO2		
Methane			
Emission Factor:	1.58E-02 lb/mmBtu	EPA Mandatory Reporting Rule	
Emissions:	9,393 lb/yr		
	4.70 tpy		
	106.73 metric tons CO2e, GWP = 25		
Nitrous Oxide			
Emission Factor:	7.92E-03 lb/mmBtu	EPA Mandatory Reporting Rule	
Emissions:	4,696 lb/yr		
	2.35 tpy		
	636.13 metric tons CO2e, GWP = 298		
Total	61,189 tpy GHG		
Total GHG Emissions (excluding biogenic CO2), point sources			
Carbon Dioxide	0		
Methane	106.73		
Nitrous Oxide	636.13		
	743 metric tons CO2e		

NET CHANGE IN HAPS/TAPS EMISSIONS -- HOG FUEL BOILERS

HAZARDOUS AIR POLLUTANTS (HAPS)

Operating Parameters:

Actual Hours of Operation

Max Heat Input

Annual Boiler Heat Input

Wellons Boiler

Existing Boilers

hours/yr

8,760

8,760

mmBtu / hr

131.0

137.9

mmBtu / yr

1,147,560

1,208,179

Emission Factors:

AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03) MACT Limit	*Boiler	CAS Number	HAP?	TAP Class (A/B) ⁽¹⁾	Emission Factor (lb/mmBtu)	Proposed Annual Emissions (tons/yr)	Current Annual Emissions (tons/yr)	Change in Emissions (tons/yr)
Acenaphthene			N	NA	9.10E-07	5.22E-04	5.50E-04	-2.76E-05
Acenaphthylene			N	NA	5.00E-06	2.87E-03	3.02E-03	-1.52E-04
Acetaldehyde		75070	Y	A	8.30E-04	4.76E-01	5.01E-01	-2.52E-02
Acetone			N	B	1.90E-04	1.09E-01	1.15E-01	-5.76E-03
Acetophenone		98862	Y	NA	3.20E-09	1.84E-06	1.93E-06	-9.70E-08
Acrolein		107028	Y	B	4.00E-03	2.30E+00	2.42E+00	-1.21E-01
Anthracene			N	NA	3.00E-06	1.72E-03	1.81E-03	-9.09E-05
Benzaldehyde			N	NA	8.50E-07	4.88E-04	5.13E-04	-2.58E-05
Benzene		71432	Y	A	4.20E-03	2.41E+00	2.54E+00	-1.27E-01
Benzoic acid			N	NA	4.70E-08	2.70E-05	2.84E-05	-1.42E-06
bis(2-ethylhexyl)phthalate (DEHP)		117817	Y	A	4.70E-08	2.70E-05	2.84E-05	-1.42E-06
Bromomethane (methyl bromide)		74839	Y	B	1.50E-05	8.61E-03	9.06E-03	-4.55E-04
2-Butanone (MEK) - Removed from HAPS		78933	N	B	5.40E-06	3.10E-03	3.26E-03	-1.64E-04
Carbazole			N	NA	1.80E-06	1.03E-03	1.09E-03	-5.46E-05
Carbon tetrachloride		56235	Y	A	4.50E-05	2.58E-02	2.72E-02	-1.36E-03
Chlorine		7782505	Y	B	7.90E-04	4.53E-01	4.77E-01	-2.39E-02
Chlorobenzene		108907	Y	B	3.30E-05	1.89E-02	1.99E-02	-1.00E-03
Chloroform		67663	Y	A	2.80E-05	1.61E-02	1.69E-02	-8.49E-04
Chloromethane (Methyl Chloride)		74873	Y	B	2.30E-05	1.32E-02	1.39E-02	-6.97E-04
2-Chloronaphthalene			N	NA	2.40E-09	1.38E-06	1.45E-06	-7.27E-08
2-Chlorophenol			N	NA	2.40E-08	1.38E-05	1.45E-05	-7.27E-07
Crotonaldehyde		123739	N	B	9.90E-06	5.68E-03	5.98E-03	-3.00E-04
Decachlorobiphenyl			N	NA	2.70E-10	1.55E-07	1.63E-07	-8.18E-09
1,2-Dibromoethene			N	NA	5.50E-05	3.16E-02	3.32E-02	-1.67E-03
Dichlorobiphenyl			N	NA	7.40E-10	4.25E-07	4.47E-07	-2.24E-08
1,2-Dichloroethane (Ethylene Dichloride)		107062	Y	A	2.90E-05	1.66E-02	1.75E-02	-8.79E-04
Dichloromethane (Methylenechloride)		75092	Y	A	2.90E-04	1.66E-01	1.75E-01	-8.79E-03
1,2-Dichloropropane (Propylene dichloride)		78875	Y	B	3.30E-05	1.89E-02	1.99E-02	-1.00E-03
2,4-Dinitrophenol		51285	Y	NA	1.80E-07	1.03E-04	1.09E-04	-5.46E-06
Dioxins and Furans, Not TCDD			N	NA	1.67E-06	9.59E-04	1.01E-03	-5.06E-05
Heptachlorodibenzo-p-dioxins			N	NA	2.00E-09			
Heptachlorodibenzo-p-furans			N	NA	2.40E-10			
Hexachlorodibenzo-p-dioxins			N	NA	1.60E-06			
Hexachlorodibenzo-p-furans			N	NA	2.80E-10			
Octachlorodibenzo-p-dioxins			N	NA	6.60E-08			
Octachlorodibenzo-p-furans			N	NA	8.80E-11			
Pentachlorodibenzo-p-dioxins			N	NA	1.50E-09			
Pentachlorodibenzo-p-furans			N	NA	4.20E-10			
Dioxins and Furans, TCDD			Y	A	1.32E-09	7.57E-07	7.97E-07	-4.00E-08
2,3,7,8-Tetrachlorodibenzo-p-dioxins		1746016	Y	A	8.60E-12			
Tetrachlorodibenzo-p-dioxins			Y	A	4.70E-10			
2,3,7,8-Tetrachlorodibenzo-p-furans			Y	A	9.00E-11			
Tetrachlorodibenzo-p-furans			Y	A	7.50E-10			
Ethylbenzene		100414	Y	B	3.10E-05	1.78E-02	1.87E-02	-9.40E-04
Formaldehyde		50000	Y	A	4.40E-03	2.52E+00	2.66E+00	-1.33E-01
Heptachlorobiphenyl			N	NA	6.60E-11	3.79E-08	3.99E-08	-2.00E-09
Hexachlorobiphenyl			N	NA	5.50E-10	3.16E-07	3.32E-07	-1.67E-08
Hexanal			N	NA	7.00E-06	4.02E-03	4.23E-03	-2.12E-04
Hydrogen chloride (Hydrochloric Acid)*		7647010	Y	B	2.20E-02	1.26E+01	1.33E+01	-6.67E-01
Isobutyraldehyde			N	NA	1.20E-05	6.89E-03	7.25E-03	-3.64E-04
Methane			N	NA	2.10E-02	1.20E+01	1.27E+01	-6.37E-01

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)	Proposed Annual Emissions (tons/yr)	Current Annual Emissions (tons/yr)	Change in Emissions (tons/yr)
2-Methylnaphthalene		N	NA	1.60E-07	9.18E-05	9.67E-05	-4.85E-06
Monochlorobiphenyl		N	NA	2.20E-10	1.26E-07	1.33E-07	-6.67E-09
Naphthalene	91203	Y	B	9.70E-05	5.57E-02	5.86E-02	-2.94E-03
2-Nitrophenol		N	NA	2.40E-07	1.38E-04	1.45E-04	-7.27E-06
4-Nitrophenol	100027	Y	NA	1.10E-07	6.31E-05	6.64E-05	-3.33E-06
Pentachlorobiphenyl		N	NA	1.20E-09	6.89E-07	7.25E-07	-3.64E-08
Pentachlorophenol	87865	Y	B	5.10E-08	2.93E-05	3.08E-05	-1.55E-06
Perylene		N	NA	5.20E-10	2.98E-07	3.14E-07	-1.58E-08
Phenanthrene		N	NA	7.00E-06	4.02E-03	4.23E-03	-2.12E-04
Phenol	108952	Y	B	5.10E-05	2.93E-02	3.08E-02	-1.55E-03
Propanal = Propionaldehyde	123386	N	B	6.10E-05	3.50E-02	3.68E-02	-1.85E-03
Polyaromatic Hydrocarbons (except 7-PAH group)		N	A	5.26E-06	3.02E-03	3.17E-03	-1.59E-04
Benzo(e)pyrene				2.60E-09			
Benzo(g,h,i)perylene				9.30E-08			
Benzo(j,k)fluoranthene				1.60E-07			
Fluoranthene				1.60E-06			
Fluorene				3.40E-06			
Polycyclic Organic Matter (POM) = 7-PAH Group		Y	A	2.94E-06	1.68E-03	1.77E-03	-8.90E-05
Benzo(a)anthracene		Y	A	6.50E-08			
Benzo(a)pyrene		Y	A	2.60E-06			
Benzo(b)fluoranthene		Y	A	1.00E-07			
Benzo(k)fluoranthene		Y	A	3.60E-08			
Indeno(1,2,3,cd)pyrene		Y	A	8.70E-08			
Chrysene		Y	A	3.80E-08			
Dibenzo(a,h)anthracene		Y	A	9.10E-09			
Pyrene		N	NA	3.70E-06	2.12E-03	2.24E-03	-1.12E-04
Styrene	100425	Y	B	1.90E-03	1.09E+00	1.15E+00	-5.76E-02
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	Y	A	8.60E-12	4.93E-09	5.20E-09	-2.61E-10
Tetrachlorobiphenyl		N	NA	2.50E-09	1.43E-06	1.51E-06	-7.58E-08
Tetrachloroethene		N	NA	3.80E-05	2.18E-02	2.30E-02	-1.15E-03
o-Tolualdehyde		N	NA	7.20E-06	4.13E-03	4.35E-03	-2.18E-04
p-Tolualdehyde		N	NA	1.10E-05	6.31E-03	6.64E-03	-3.33E-04
Toluene	108883	Y	B	9.20E-04	5.28E-01	5.56E-01	-2.79E-02
Trichlorobiphenyl		N	NA	2.60E-09	1.49E-06	1.57E-06	-7.88E-08
1,1,1-Trichloroethane (Methyl Chloroform)	71556	Y	B	3.10E-05	1.78E-02	1.87E-02	-9.40E-04
Trichloroethene (Trichloroethylene)	79016	Y	A	3.00E-05	1.72E-02	1.81E-02	-9.09E-04
Trichlorofluoromethane	75694	Y	NA	4.10E-05	2.35E-02	2.48E-02	-1.24E-03
2,4,6-Trichlorophenol	88062	Y	A	2.20E-08	1.26E-05	1.33E-05	-6.67E-07
Vinyl Chloride	75014	Y	A	1.80E-05	1.03E-02	1.09E-02	-5.46E-04
o-Xylene	95476	Y	B	2.50E-05	1.43E-02	1.51E-02	-7.58E-04
Antimony	7440-36-0	Y	B	7.90E-06	4.53E-03	4.77E-03	-2.39E-04
Arsenic	7440-38-2	Y	A	2.20E-05	1.26E-02	1.33E-02	-6.67E-04
Barium	7440-39-3	Y	B	6.98E-05	4.00E-02	4.21E-02	-2.11E-03
Beryllium	7440-41-7	Y	A	4.36E-07	2.50E-04	2.63E-04	-1.32E-05
Cadmium	7440-43-9	Y	A	4.10E-06	2.35E-03	2.48E-03	-1.24E-04
Chromium, total	16065-83-1	Y	B	2.10E-05	1.20E-02	1.27E-02	-6.37E-04
Chromium, hexavalent	18540-29-9	Y	A	3.50E-06	2.01E-03	2.11E-03	-1.06E-04
Cobalt	7440-48-4	Y	B	6.50E-06	3.73E-03	3.93E-03	-1.97E-04
Copper	7440-50-8	N	B	5.23E-06	3.00E-03	3.16E-03	-1.59E-04
Iron		N	NA	9.90E-04	5.68E-01	5.98E-01	-3.00E-02
Lead	7439-92-1	Y	NA	4.80E-05	2.75E-02	2.90E-02	-1.45E-03
Manganese	7439-96-5	N	B	1.60E-03	9.18E-01	9.67E-01	-4.85E-02
Mercury (removed from TAPs)*, new boiler	7439-97-6	Y	NA	8.10E-07	4.65E-04		
Mercury (removed from TAPs)*, existing boiler	7439-97-6	Y	NA	5.70E-06		3.44E-03	-2.98E-03
Molybdenum	7439-98-7	N	B	2.10E-06	1.20E-03	1.27E-03	-6.37E-05
Nickel	7440-02-0	Y	A	3.30E-05	1.89E-02	1.99E-02	-1.00E-03
Phosphorus	7223-14-0	N	B	3.27E-04	1.88E-01	1.97E-01	-9.91E-03
Potassium		N	NA	3.90E-02	2.24E+01	2.36E+01	-1.18E+00
Selenium	7782-49-2	Y	B	2.80E-06	1.61E-03	1.69E-03	-8.49E-05

Emission Factors:							
AP-42 Ch.1.6, Tables 1.6-3 and 1.6-4 (9/03) MACT Limit	*Boiler CAS Number	HAP?	TAP Class (A/B) ⁽¹⁾	Emission Factor (lb/mmBtu)	Proposed Annual Emissions (tons/yr)	Current Annual Emissions (tons/yr)	Change in Emissions (tons/yr)
Silver	7440-22-4	N	B	1.70E-03	9.75E-01	1.03E+00	-5.15E-02
Sodium		N	NA	3.60E-04	2.07E-01	2.17E-01	-1.09E-02
Strontium		N	NA	1.00E-05	5.74E-03	6.04E-03	-3.03E-04
Tin	7440-31-5	N	B	2.30E-05	1.32E-02	1.39E-02	-6.97E-04
Titanium		N	NA	2.00E-05	1.15E-02	1.21E-02	-6.06E-04
Vanadium	1314-62-1	N	B	9.80E-07	5.62E-04	5.92E-04	-2.97E-05
Yttrium		N	NA	3.00E-07	1.72E-04	1.81E-04	-9.09E-06
Zinc		N	NA	4.20E-04	2.41E-01	2.54E-01	-1.27E-02

(1) TAP Class A is regulated under IDAPA 58.01.01.586 and TAP Class B is regulated under IDAPA 58.01.01.585.

HAPS EMISSIONS -- PROPOSED PTE WELLONS BOILER

HAZARDOUS AIR POLLUTANTS (HAPS)

Operating Parameters:

Actual Hours of Operation

hours/yr

Wellons Boiler

8,760

Max Heat Input

mmBtu / hr

131.0

Annual Boiler Heat Input¹

mmBtu / yr

1,147,560

Hazardous or Toxic Air Pollutant (HAP/TAP)	CAS Number	Emission Factor (lb/mmBtu)	Wellons Boiler ³ (tons/yr)
Acetaldehyde	75070	8.30E-04	4.76E-01
Acetophenone	98862	3.20E-09	1.84E-06
Acrolein	107028	4.00E-03	2.30
Benzene	71432	4.20E-03	2.41
bis(2-ethylhexyl)phthalate (DEHP)	117817	4.70E-08	2.70E-05
Bromomethane (methyl bromide)	74839	1.50E-05	8.61E-03
Carbon tetrachloride	56235	4.50E-05	2.58E-02
Chlorine	7782505	7.90E-04	4.53E-01
Chlorobenzene	108907	3.30E-05	1.89E-02
Chloroform	67663	2.80E-05	1.61E-02
Chloromethane (Methyl Chloride)	74873	2.30E-05	1.32E-02
1,2-Dichloroethane (Ethylene Dichloride)	107062	2.90E-05	1.66E-02
Dichloromethane (Methylenechloride)	75092	2.90E-04	1.66E-01
1,2-Dichloropropane (Propylene dichloride)	78875	3.30E-05	1.89E-02
2,4 Dinitrophenol	51285	1.80E-07	1.03E-04
Dioxins and Furans, TCDD, including: ²		1.32E-09	7.57E-07
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	8.60E-12	---
Tetrachlorodibenzo-p-dioxins		4.70E-10	---
2,3,7,8-Tetrachlorodibenzo-p-furans		9.00E-11	---
Tetrachlorodibenzo-p-furans		7.50E-10	---
Ethyl benzene	100414	3.10E-05	1.78E-02
Formaldehyde	50000	4.40E-03	2.52
Hydrogen chloride (Hydrochloric Acid)	7647010	2.20E-02	12.62
Naphthalene	91203	9.70E-05	5.57E-02
4-Nitrophenol	100027	1.10E-07	6.31E-05
Pentachlorophenol	87865	5.10E-08	2.93E-05
Phenol	108952	5.10E-05	2.93E-02
Propanal = Propionaldehyde	123386	6.10E-05	3.50E-02
Polycyclic Organic Matter (POM) = 7-PAH Group, including: ²		2.94E-06	1.68E-03
Benzo(a)anthracene		6.50E-08	---
Benzo(a)pyrene		2.60E-06	---
Benzo(b)fluoranthene		1.00E-07	---
Benzo(k)fluoranthene		3.60E-08	---
Indeno(1,2,3,cd)pyrene		8.70E-08	---
Chrysene		3.80E-08	---
Dibenzo(a,h)anthracene		9.10E-09	---
Styrene	100425	1.90E-03	1.09
2,3,7,8-Tetrachlorodibenzo-p-dioxins	1746016	8.60E-12	4.93E-09
Toluene	108883	9.20E-04	5.28E-01
1,1,1-Trichloroethane (Methyl Chloroform)	71556	3.10E-05	1.78E-02
Trichloroethene (Trichloroethylene)	79016	3.00E-05	1.72E-02
2,4,6-Trichlorophenol	88062	2.20E-08	1.26E-05
Vinyl Chloride	75014	1.80E-05	1.03E-02
o-Xylene	95476	2.50E-05	1.43E-02
Antimony	7440-36-0	7.90E-06	4.53E-03
Arsenic	7440-38-2	2.20E-05	1.26E-02
Beryllium	7440-41-7	4.36E-07	2.50E-04
Cadmium	7440-43-9	4.10E-06	2.35E-03
Chromium, total	16065-83-1	2.10E-05	1.20E-02
Chromium, hexavalent (Cr VI)	18540-29-9	3.50E-06	2.01E-03
Cobalt	7440-48-4	6.50E-06	3.73E-03
Lead	7439-92-1	4.80E-05	2.75E-02
Manganese	7439-96-5	1.60E-03	9.18E-01
Mercury (removed from TAPs)	7439-97-6	8.10E-07	4.65E-04
Nickel	7440-02-0	3.30E-05	1.89E-02
Phosphorus	7223-14-0	3.27E-04	1.88E-01
Selenium	7782-49-2	2.80E-06	1.61E-03

Total HAPS	24.08
Max Individual HAP (Hydrogen Chloride)	12.62

Notes:

¹ Annual Boiler Heat Input Calculation

Annual Heat Input = Max Heat Input x Actual Hours of Operation

$$1,147,560 \text{ mmBtu/yr} = 131 \text{ mmBtu/yr} \times 8,760 \text{ hrs/yr}$$

² Pollutant group emission factors (such as TCDD and POM) were calculated by summing the individual pollutant emission factors in their respective group

Example: TCDD

$$EF(\text{TCDD}) = EF(2,3,7,8\text{-Tetrachlorodibenzo-p-dioxins}) + EF(\text{Tetrachlorodibenzo-p-dioxins}) + EF(2,3,7,8\text{-Tetrachlorodibenzo-p-furans}) + EF(\text{Tetrachlorodibenzo-p-furans})$$

$$1.32\text{E-}09 \text{ lb/mmBtu} = 8.60\text{E-}12 + 4.70\text{E-}10 + 9.00\text{E-}11 + 7.50\text{E-}10$$

³ HAPS PTE Emissions Calculation

Emissions = Annual Boiler Heat Input x Emission Factor x (1 ton/2000 lbs)

Example: Acetaldehyde

$$4.76\text{E-}01 \text{ tons/yr} = 1,147,560 \text{ mmBtu/yr} \times 8.30\text{E-}04 \text{ lb/mmBtu} \times (1 \text{ ton}/2000 \text{ lbs})$$

MILL FUGITIVE SOURCES

Emission Factors

Fugitive Emissions Source	PM10 ef	PM2.5 ef	Units	Control Eff.	Emission Factor Reference
DEBARKER, PF1	0.011	0.001947	lb/ton logs	80%	AIRS 3-07-008-01, NCASI for PM2.5%. 80% control for partial enclosure.
BARK HOG, PF2	0.011	0.001947	lb/BDT bark	90%	AIRS 3-07-008-01, NCASI for PM2.5%. 90% control for full enclosure.
HOG FUEL TRANSFER TO FUEL BIN	0.00035	0.00005	lb/BDT bark	90%	FARR drop factor "wet", 90% for enclosure
FUEL CONVEYED TO WELLONS	0.00035	0.00005	lb/BDT bark	50%	FARR drop factor "wet", 50% covered
B1 FUEL CONVEYED TO BOILER	0.00035	0.00005	lb/BDT bark	50%	FARR drop factor "wet", 50% covered
B2 FUEL LOADED TO FUEL PILE	0.00035	0.00005	lb/BDT bark	0%	FARR drop factor "wet", open discharge
B2 FUEL TO HOPPER	0.00035	0.00005	lb/BDT bark	0%	FARR drop factor "wet", open discharge
SAWMILL SAWING, INDOOR	0.175	0.030625	lb/ton logs, less bark weight	99.9%	FARR PM10 sawing factor, NCASI PM2.5%, 99.9% control indoors (FARR uses 100%),
SAWDUST CONVEYING	0.00035	0.00005	lb/BDT sawdust	50%	FARR drop factor "wet", 50% covered
SAWMILL TRUCK BIN TOP VENT, PF3	0.00035	0.00005	lb/BDT sawdust	90%	FARR drop factor "wet", 90% control enclosure
SAWDUST BIN TRUCK LOADOUT, PF5	0.00035	0.00005	lb/BDT sawdust	80%	FARR drop factor "wet", 80% control for side panels
CHIP TRUCK BIN TOP VENT, PF4	0.00035	0.00005	lb/BDT chips	90%	FARR drop factor "wet", 90% control enclosure
CHIP BIN TRUCK LOADOUT, PF6	0.00035	0.00005	lb/BDT chips	80%	FARR drop factor "wet", 80% control for side panels
PLANER SHAVINGS BIN TRUCK LOADOUT, PF7	0.0007	0.0001	lb/BDT shavings	80%	FARR drop factor "dry", 80% control for sides panels
PLANER CHIPS LOADOUT, PF7	0.0007	0.0001	lb/BDT planer chips	80%	FARR drop factor "dry", 80% control for sides panels

Potential Emissions

Fugitive Emissions Source	PM10	PM10	PM2.5	PM2.5	Notes
	tpy	lb/hr (daily)	tpy	lb/hr (daily)	
DEBARKER, PF1	1.26E+00	3.36E-01	2.23E-01	5.95E-02	No change
BARK HOG, PF2	2.68E-02	7.15E-03	4.74E-03	1.27E-03	No change
HOG FUEL TRANSFER TO FUEL BIN	8.51E-04	2.27E-04	1.22E-04	3.25E-05	No Change
FUEL CONVEYED TO WELLONS	4.26E-03	1.14E-03	6.08E-04	1.62E-04	Added source, all hog fuel
B1 FUEL CONVEYED TO BOILER	2.13E-03	5.69E-04	3.04E-04	8.12E-05	Removed source, 1/2 hog fuel
B2 FUEL LOADED TO FUEL PILE	4.26E-03	1.14E-03	6.08E-04	1.62E-04	Removed source, 1/2 hog fuel
B2 FUEL TO HOPPER	4.26E-03	1.14E-03	6.08E-04	1.62E-04	Removed source, 1/2 hog fuel
SAWMILL SAWING, INDOOR	9.17E-02	2.45E-02	1.60E-02	4.28E-03	No Change
SAWDUST CONVEYING	7.39E-03	1.97E-03	1.06E-03	2.82E-04	No Change
SAWMILL TRUCK BIN TOP VENT, PF3	1.48E-03	3.95E-04	2.11E-04	5.64E-05	No Change
SAWDUST BIN TRUCK LOADOUT, PF5	2.96E-03	7.90E-04	4.22E-04	1.13E-04	No Change
CHIP TRUCK BIN TOP VENT, PF4	2.65E-03	7.09E-04	3.79E-04	1.01E-04	No Change
CHIP BIN TRUCK LOADOUT, PF6	5.31E-03	1.42E-03	7.58E-04	2.03E-04	No Change
PLANER SHAVINGS BIN TRUCK LOADOUT, PF7	4.35E-03	1.16E-03	6.21E-04	1.66E-04	No Change
PLANER CHIPS LOADOUT, PF7	1.10E-03	2.94E-04	1.57E-04	4.20E-05	No Change

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

LUMBER DRY KILNS, EU2

318,000 mbdft/yr, lumber dried

CRITERIA POLLUTANTS

PM10 :	Emission Factor:	0.038 lbs/1000 bd.ft.	Willamette Ind. 1998 Source Tests
	Emissions:	6.04 tons/year	Douglas fir and Hemlock
		33.11 lbs/day	
		1.38 lb/hr	0.0216 lb/hr/vent
PM2.5 :	Emission Factor:	0.033 lbs/1000 bd.ft.	Willamette Ind. 1998 Source Tests
	Emissions:	5.25 tons/year	Douglas fir and Hemlock
		28.75 lbs/day	
		1.20 lb/hr	0.0187 lb/hr/vent
VOC:	Emission Factor:	1.08 lbs/1000 bd.ft.	Species-dependent emission factor
	Emissions:	171.91 tons/year	VOC Emissions based on
		39.25 lbs/hr	mix shown below.

HAZARDOUS AIR POLLUTANTS

Total HAP	Emission Factor:	0.12 lbs/1000 bd.ft.	Species-dependent emission factor
	Emissions:	19.22 tons/year	HAP Emissions based on
		4.39 lbs/hr	mix shown below.
Methanol, highest single HAP	Emission Factor:	0.075 lbs/1000 bd.ft.	Species-dependent emission factor
	Emissions:	11.90 tons/year	HAP Emissions based on
		2.72 lbs/hr	mix shown below.

Wood Species, representative:	% of Total	VOC (lb/MBdft)	Weighted (lb/MBdft)	Total HAP (lb/MBdft)	Weighted (lb/MBdft)	Methanol (lb/MBdft)	Weighted ^a (lb/MBdft)
Ponderosa Pine	30.0%	2.46	0.74	0.148	0.04	0.102	0.03
Douglas Fir	15.3%	1.03	0.16	0.171	0.03	0.096	0.01
Larch	0.0%	0.25	0.00	0.291	0.00	0.187	0.00
Hemlock		0.24	0.00	0.243	0.00	0.133	0.00
Grand (white) Fir		0.70	0.00	0.189	0.00	0.122	0.00
Hemlock, Hem-fir	0.0%	0.70	0.00	0.243	0.00	0.133	0.00
Lodgepole		1.32	0.00	0.092	0.00	0.060	0.00
Spruce		0.11	0.00	0.092	0.00	0.054	0.00
ESLP: Englemann Spr. Lodgepole	8.8%	1.32	0.12	0.092	0.01	0.054	0.0048
Alpine Fir, White Fir	0.0%	0.70	0.00	0.291	0.00	0.187	0.00
Cedar	45.9%	0.15	0.07	0.092	0.04	0.054	0.02
Other	0.0%	2.46	0.00	0.291	0.00	0.187	0.00
Total	100.0%		1.08		0.12		0.075

Notes: (a) Proposed Emission Factors

Idaho Forest-based Dry Kiln Emission Factors Units are pounds per thousand board feet (lb/MBF)

1998 Source Test	PM Total (lb/MBF)	PM ₁₀ (lb/MBF)	PM _{2.5} (lb/MBF)
Coastal Hemlock	0.051	0.051	0.048
Douglas-fir	0.024	0.024	0.018
Average	0.038	0.038	0.033

Total PM was assumed to be PM10. Condensable fraction was determine to be PM2.5 fraction

Idaho Forest Group - Laclede
Dry Kiln Haps, All

EMISSIONS YEAR	PTE
----------------	-----

* white wood is Alpine Fir, etc.

ENTER	
Total MBF processed	318,000
% Douglas Fir	15%
% Larch	0%
% Hem-Fir	0%
% Ponderosa Pine	30%
% Alpine Fir, White Fir	0%
% ESLP	9%
% Cedar	46%
% Other (name species)	0%

100% 318,000

48,495 MBF/Yr by species calculated by Total MBF * % species

EMISSION FACTORS:	Factors from OSU and U of I Studies, available upon request					
Pollutant	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propionaldehyde	Acrolein
Douglas Fir	0.171	0.096	0.0033	0.0625	0.0007	0.0010
Larch	0.291	0.187	0.0032	0.1029	0.0084	0.0016
Hem Fir	0.243	0.133	0.0032	0.1029	0.0084	0.0016
Ponderosa Pine	0.148	0.102	0.0067	0.0334	0.0027	0.0034
Alpine Fir, Wite Fir	0.291	0.187	0.0028	0.1130	0.0010	0.0016
ESLP	0.092	0.054	0.0028	0.1130	0.0010	0.0016
Cedar (<200)	0.092	0.054	0.0030	0.0333	0.0005	0.0008

EMISSIONS	Emission lb/Yr					
Species	Total HAP	Methanol	Formal-dehyde	Acetal-dehyde	Propion-aldehyde	Acrolein
Douglas Fir	8293	4656	158	3031	34	47
Larch	0	0	0	0	0	0
Western Hemlock	0	0	0	0	0	0
Ponderosa Pine	14133	9741	640	3188	258	327
White Fir (white wood)	0	0	0	0	0	0
ESLP	2583	1516	79	3173	28	45
Cedar	13426	7880	436	4855	76	113
TOTAL, lb/yr	38,435	23,793	1,313	14,247	395	531
TOTAL, ton/yr	19.22	11.90	0.66	7.12	0.20	0.27

CYCLONE AND BAGHOUSE PTE EMISSIONS

Source	PM10 ef (lb/BDT)	reference	PM2.5 ef (lb/BDT)	reference
PLANER CHIPPER CYCLONE , EU3	0.20	AQ-EF02, cyclone	0.10	50% of PM10 ⁽¹⁾
PLANER SHAVINGS CYCLONE BAGHOUSE, EU4	0.040	AQ-EF02, shavings	0.027	67% of PM10 ⁽¹⁾
PLANER SHAVINGS CYCLONE BAGHOUSE, EU5	0.040	AQ-EF02, shavings	0.027	67% of PM10 ⁽¹⁾
SHAVINGS BIN VENT BAGHOUSE, EU6	0.000070	Manufacturer Specifications	0.000047	67% of PM10 ⁽¹⁾

(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)
Planer Chip Cyclone (EU3)	15,710	BDT/yr	1.5710		0.7855	
	50	BDT/day		0.4196		0.2098
Planer Shavings Cyclone Baghouse (EU4)	31,044	BDT/yr	0.6209		0.4160	
	99	BDT/day		0.1658		0.1111
Planer Shavings Cyclone Baghouse (EU5)	31,044	BDT/yr	0.6209		0.4160	
	99	BDT/day		0.1658		0.1111
Shavings Bin Vent Baghouse (EU6)	77,798	BDT/yr	0.0027		0.0018	
	249	BDT/day		0.00072		0.00048

Conversion of minutes to hours	60 min/hr
Conversion of grains to lbs	7000 gr/lb

PAVED ROADS Road dust emissions are unchanged by the project.
 Calculations based on AP-42 Section 13.2.1.3, rev. 1/11

Source	Class	Number Trips Per Year	Distance per Trip (miles)	VTM per Year	Avg. Vehicle Weight W	Weighted Vehicle Weight
Log Trucks	Paved, Loaded	40,886	0.20	8,177	40	9.97
	Paved, Empty	40,886	0.20	8,177	13	3.24
Log Loaders	Paved, Loaded	959	0.15	144	20	0.09
	Paved, Empty	959	0.15	144	15	0.07
Chip Trucks	Paved, Loaded	5,862	0.25	1,465	40	1.79
	Paved, Empty	5,862	0.25	1,465	13	0.58
Shavings Trucks	Paved, Loaded	3,044	0.25	761	40	0.93
	Paved, Empty	3,044	0.25	761	13	0.30
Sawdust Trucks	Paved, Loaded	2,958	0.25	739	40	0.90
	Paved, Empty	2,958	0.25	739	13	0.29
Lumber Trucks	Paved, Loaded	17,667	0.25	4,417	40	5.39
	Paved, Empty	17,667	0.25	4,417	13	1.75
Bucket Loaders	Paved, Loaded	500	0.15	75	15	0.03
	Paved, Empty	500	0.15	75	12	0.03
Misc. Vehicles incl employee	Paved	5,000	0.25	1,250	3	0.11
		148,749		32,807		25

$$E = k(sL)^{0.91}(W)^{1.02} [1 - 1.2 \cdot P/N]$$

	PM	PM10	PM2.5	P=	120
k =	0.011	0.0022	0.00054	N=	365
sL=	1.1	1.1	1.1		
W =	25	25	25		
E=	0.197	0.039	0.010		
	lb/VTM	lb/VTM	lb/VTM		
% control from washing/sw	50%	50%	50%		

Total PM Emissions:	1.6	tpy
Total PM10 Emissions:	0.32	tpy
Total PM2.5 Emissions:	0.08	tpy

Idaho Forest Group – Laclede, Fire Water Pump

Cummins Diesel

220 horsepower

1,540,000 Btu/hr
11.2 Gallons/hr
1124 gallons/yr

Pump keeps fire suppression system charged in the event of a power outage. Tested monthly.

100 Hours of Operation

Testing and during power outages

PM10/PM2.5

Emission Factor:
Emissions:

2.20E-03 lb/hp-hr
0.02 tons/year
0.48 lb/hr

AP-42, Section 3.3, Table 3.3-1
All PM assumed to be <1um.

Sulfur Dioxide

Emission Factor:
Emissions:

2.05E-03 lb/hp-hr
0.02 tons/year
0.45 lb/hr

AP-42, Section 3.3, Table 3.3-1

Nitrogen Oxides (NOx)

Emission Factor:
Emissions:

0.031 lb/hp-hr
0.34 tons/year
6.82 lb/hr

AP-42, Section 3.3, Table 3.3-1

Volatile Organic Compounds (VOC) - Total Organic Compounds

Emission Factor:
Emissions:

2.51E-03 lb/hp-hr
0.03 tons/year
0.55 lb/hr

AP-42, Section 3.3, Table 3.3-1

Carbon Monoxide (CO)

Emission Factor:
Emissions:

6.68E-03 lb/hp-hr
0.07 tons/year
1.47 lb/hr

AP-42, Section 3.3, Table 3.3-1

Hazardous Air Pollutants (HAPS)

Factors from AP-42, Section 3.3, Table 3.3-2

Pollutant	CAS Number	Emission Factor (lb/mmBtu)	Emissions (lb/hr)	Emissions (tons/year)
Benzene	71432	9.33E-04	1.44E-03	6.29E-03
Toluene	108883	4.09E-04	6.30E-04	2.76E-03
Xylenes	1330207	2.85E-04	4.39E-04	1.92E-03
1,3-Butadiene	106990	3.91E-05	6.02E-05	2.64E-04
Formaldehyde	50000	1.18E-03	1.82E-03	7.96E-03
Acetaldehyde	75070	7.67E-04	1.18E-03	5.17E-03
Acrolein	107028	9.25E-05	1.42E-04	6.24E-04
Naphthalene	91203	8.48E-05	1.31E-04	5.72E-04
Total			5.84E-03	2.56E-02

APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

(2017AAG640)

MEMORANDUM

DATE: March 24, 2017

TO: Shawnee Chen, Permit Writer, Air Program

FROM: Thomas Swain, Air Quality Modeler, Analyst 3, Air Program

PROJECT: Idaho Forest Group, Laclede (IFG-Laclede) facility in Laclede, Idaho, Permit to Construct (PTC) P-2017.0001, Facility ID No. 017-00027, Project 61833

SUBJECT: Demonstration of Compliance with IDAPA 58.01.01.203.02 (NAAQS) and 203.03 (TAPs) as it relates to air quality impact analyses.

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1.0 Summary

The Idaho Forest Group (IFG), Laclede, submitted an application for a Permit to Construct (PTC) on January 4, 2017, for modifications their existing facility located in Laclede, Idaho.

IFG is a facility that processes lumber products. The main emission processes are the sawmill, the steam plant, the dry kilns, and the planer mill. Timber/logs are debarked and cut to specified dimensions. Green lumber is first dried in the dry kilns and then planed in the planer mill. The final product lumber is packaged and shipped by truck. Bark is hogged and used in the boiler as fuel. The facility is located in Laclede, Idaho, within Bonner County on Riley Creek Road, 60 miles south of the Canadian border. This modification to the permit was requested to account for the replacement of the existing hog-fueled boilers with a newer fuel-cell Wellons boiler having a heat capacity of 131 mmBTU/hr. This process will insure that IFG-Laclede will comply with the Boiler MACT standards. By implementing this process, there will be a net emissions reduction in CO that will cause the facility to no longer be a PSD-major facility.

The entire process is discussed in detail in the main body of the Department of Environmental Quality (DEQ) Statement of Basis supporting the issued proposed PTC. This modeling review memorandum provides a summary and approval of the ambient air impact analyses submitted with the permit application. It also describes DEQ's review of those analyses, DEQ's verification analyses, additional clarifications, and conclusions.

Project-specific air quality impact analyses involving atmospheric dispersion modeling of estimated emissions associated with the facility were submitted to DEQ to demonstrate that the facility would not cause or significantly contribute to a violation of any ambient air quality standard, as required by IDAPA 58.01.01.203.02 and 203.03 (Idaho Air Rules Section 203.02 and 203.03).

Bison Engineering (BISON) performed the ambient air impact analyses for this project, on behalf of IFG-Laclede. The analyses were performed to demonstrate compliance with air quality standards. The DEQ review summarized by this memorandum addressed only the rules, policies, methods, and data pertaining to the air impact analyses used to demonstrate that the estimated emissions increases at the facility associated with the proposed project will not cause or significantly contribute to a violation of any applicable air quality standard. This review did not evaluate compliance with other rules or analyses that do not pertain to the air impact analyses. Evaluation of emissions estimates is the responsibility of the permit writer and is addressed in the main body of the Statement of Basis. The accuracy of emissions estimates was not evaluated as part of DEQ's review of the air impact analyses described in this modeling review memorandum.

A pre-application meeting for this project was held on October 18, 2017, at which various items were discussed. A modeling protocol was submitted on November 10, 2016. Suitable meteorological data from Sandpoint, Idaho, was deemed acceptable for this minor source project in early December. The protocol was approved, with conditions, on December 16, 2016. Included in these conditions was usage of an updated meteorological data set for the period 2011-2015 (provided by DEQ), and usage of ambient background concentration values obtained from NWAIRQUEST⁽²⁾. A permit application was submitted on January 4, 2017. This application was determined to be complete on February 2, 2017. DEQ had several questions/concerns with the analyses after the completeness date. These included omission of an existing emergency fire pump engine from the emissions source inventory and the lack of documentation of exhaust flow parameters for the baghouse/cyclone sources. The applicant responded with a revised source inventory and modeling files, which included the emergency fire pump engine, on February 16, 2017. These revisions resulted in a slight increase in modeled concentrations from what was originally submitted, but there were still no exceedances of NAAQS for all criteria pollutants. On February 18, 2017, the applicant provided additional information on the derivation of exhaust flows from the baghouse and cyclone sources, which

satisfied DEQ's request.

The final submitted air quality impact analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data (review of emissions estimates was addressed by the DEQ permit writer); 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that estimated potential/allowable emissions are at a level defined as below regulatory concern (BRC) and do not require a National Ambient Air Quality Standard (NAAQS) compliance demonstration; b) that predicted pollutant concentrations from emissions associated with the project as modeled were below Significant Impact Levels (SILs) or other applicable regulatory thresholds; or c) that predicted pollutant concentrations from emissions associated with the project as modeled, when appropriately combined with co-contributing sources and background concentrations, were below applicable NAAQS at ambient air locations where and when the project has a significant impact; 5) showed that Toxic Air Pollutant (TAP) emissions increases associated with the project will not result in increased ambient air impacts exceeding allowable TAP increments.

Table 1 presents key assumptions and results to be considered in the development of the permit.

Air impact analyses are required by Idaho Air Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (*Guideline on Air Quality Models*). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information and analyses demonstrated to the satisfaction of the Department that operation of the proposed facility will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	Explanation/Consideration
General Emissions Rates. Emissions rates used in the modeling analyses, as listed in this memorandum, represent maximum potential emissions as given by design capacity or as limited by the issued permit for the specific pollutant and averaging period.	Compliance has not been demonstrated for emissions rates greater than those used in the modeling analyses.
Modeling Thresholds for Criteria Pollutant Emissions. Maximum short-term and long-term emissions of PM ₁₀ , PM _{2.5} , SO ₂ , CO, and oxides of nitrogen (NO _x) associated with the proposed project are above the Level I threshold for each pollutant. Therefore, a demonstration of compliance with NAAQS was done for these pollutants and averaging times.	Project-specific air impact analyses demonstrating compliance with NAAQS, as required by Idaho Air Rules Section 203.02, are required for pollutants having an emissions increase that is greater than Level I level modeling applicability thresholds. Compliance with NAAQS has not been demonstrated for emissions that exceed the emission estimates presented in the application.
TAPS Modeling. Emission rates of all TAPS not governed by 40 CFR 63, per Idaho Air Rules Section 210.20 for those subset of TAPS in sections 585 and 586, did not exceed Emissions Screening Level (EL) rates.	Air impact analyses demonstrating compliance with TAPs allowable impact increments, as required by Idaho Air Rules Section 203.03, is required for pollutants having an emissions rate greater than Emissions Screening Levels (ELs). Therefore, no demonstration of compliance with TAPs increments was required.

2.0 Background Information

This section provides background information applicable to the project and the site where the facility is located. It also provides a brief description of the applicable air impact analyses requirements for the project.

2.1 Project Description

IFG-Laclede is an existing facility located in Laclede, Idaho. The facility processes raw timber into lumber products of specified type and dimensions, which are then shipped out by trucks for sale. This project was submitted as an application for a Permit to Construct (PTC) P-2017.0001. The facility intends to:

- 1) Replace the two existing hog fuel stoker boilers with one newer Wellons hog-fuel fuel-cell boiler
- 2) Decrease the PTE CO emissions to less than 250 tons/year; therefore, it will no longer be a PSD-major facility, and will not be subject to various PSD applicability regulations.

BISON's air impact analyses, as part of the permit application, was submitted to show that emissions increases associated with the proposed modification do not cause or contribute to an exceedance of any NAAQS or TAPs Acceptable Ambient Concentration (AAC) or Acceptable Ambient Concentration of a Carcinogen (AACC). A detailed description of the facility is listed in Section 1 of the submitted application.

2.2 Proposed Location and Area Classification

IFG-Laclede is located in Laclede, Idaho, in Bonner County, 60 miles south of the Canadian border and 18 miles east of the Washington state border. This area is designated as an attainment or unclassifiable area for sulfur dioxide (SO₂), nitrogen dioxide (NO₂), carbon monoxide (CO), lead (Pb), ozone (O₃), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM₁₀), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM_{2.5}). The area is not classified as non-attainment for any criteria pollutants.

2.3 Air Impact Analyses Required for All Permits to Construct

Criteria Pollutant and TAP Impact Analyses for a PTC are addressed in Idaho Air Rules Sections 203.02 and 203.03:

No permit to construct shall be granted for a new or modified stationary source unless the applicant shows to the satisfaction of the Department all of the following:

02. NAAQS. *The stationary source or modification would not cause or significantly contribute to a violation of any ambient air quality standard.*

03. Toxic Air Pollutants. *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Atmospheric dispersion modeling, using computerized simulations, is used to demonstrate compliance with both NAAQS and TAPs. Idaho Air Rules Section 202.02 states:

Estimates of Ambient Concentrations. *All estimates of ambient concentrations shall be based on the applicable air quality models, data bases, and other requirements specified in 40 CFR 51 Appendix*

W (Guideline on Air Quality Models).

2.4 Significant Impact Level and Cumulative NAAQS Impact Analyses

The Significant Impact Level (SIL) analysis for a new facility or proposed modification to a facility involves modeling estimated criteria air pollutant emissions from the facility or modification to determine the potential impacts to ambient air. Air impact analyses are required by Idaho Air Rules to be conducted per methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition.

A facility or modification is considered to have a significant impact on air quality if maximum modeled impacts to ambient air exceed the established SIL listed in Idaho Air Rules Section 006 (referred to as a significant contribution in Idaho Air Rules) or as incorporated by reference as per Idaho Air Rules Section 107.03.b. Table 2 lists the applicable SILs.

If modeled maximum pollutant impacts to ambient air from the emissions sources associated with a new facility or modification exceed the SILs, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with NAAQS and Idaho Air Rules Section 203.02.

DEQ has developed modeling applicability thresholds that effectively assure that project-related emissions increases below stated values will result in ambient air impacts below the applicable SILs. The threshold levels and dispersion modeling analyses supporting those levels are presented in the *State of Idaho Guideline for Performing Air Quality Impact Analyses¹ (Idaho Air Modeling Guideline)*. Use of a modeling threshold represents the use of conservative air impact modeling, performed in support of the threshold, as a project SIL analysis. Project-specific modeling applicability for this project is addressed in Section 3.1.1 of this memorandum.

A cumulative NAAQS impact analysis for attainment area pollutants involves assessing ambient impacts (typically the design values consistent with the form of the standard) from facility-wide emissions, and emissions from any nearby co-contributing sources, and then adding a DEQ-approved background concentration value to the modeled result that is appropriate for the criteria pollutant/averaging-period at the facility location and the area of significant impact. The resulting pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SILs and specifies the modeled design value that must be used for comparison to the NAAQS. NAAQS compliance is evaluated on a receptor-by-receptor basis for the modeling domain.

If the cumulative NAAQS impact analysis indicates a violation of the standard, the permit may not be issued if the proposed project has a significant contribution (exceeding the SIL) to the modeled violation. This evaluation is made specific to both time and space. If the SIL analysis indicates the facility/modification has an impact exceeding the SIL, the facility might not have a significant contribution to a violation if impacts are below the SIL at the specific receptor showing the violation during the time periods when a modeled violation occurred.

Table 2. APPLICABLE REGULATORY LIMITS				
Pollutant	Averaging Period	Significant Impact Levels^a (µg/m³)^b	Regulatory Limit^c (µg/m³)	Modeled Design Value Used^d
PM ₁₀ ^e	24-hour	5.0	150 ^f	Maximum 6 th highest ^g
PM _{2.5} ^h	24-hour	1.2	35 ⁱ	Mean of maximum 8 th highest ^j
	Annual	0.3	12 ^k	Mean of maximum 1st highest ^j
Carbon monoxide (CO)	1-hour	2,000	40,000 ^m	Maximum 2 nd highest ⁿ
	8-hour	500	10,000 ^m	Maximum 2 nd highest ⁿ
Sulfur Dioxide (SO ₂)	1-hour	3 ppb ^o (7.8 µg/m ³)	75 ppb ^p (196 µg/m ³)	Mean of maximum 4 th highest ^q
	3-hour	25	1,300 ^m	Maximum 2 nd highest ⁿ
	24-hour	5	365 ^m	Maximum 2 nd highest ⁿ
	Annual	1.0	80 ^r	Maximum 1 st highest ⁿ
Nitrogen Dioxide (NO ₂)	1-hour	4 ppb (7.5 µg/m ³)	100 ppb ^s (188 µg/m ³)	Mean of maximum 8 th highest ^t
	Annual	1.0	100 ^r	Maximum 1 st highest ⁿ
Lead (Pb)	3-month ^u	NA	0.15 ^r	Maximum 1 st highest ⁿ
	Quarterly	NA	1.5 ^r	Maximum 1 st highest ⁿ
Ozone (O ₃)	8-hour	40 TPY VOC ^v	75 ppb ^w	Not typically modeled

- a. Idaho Air Rules Section 006 (definition for significant contribution) or as incorporated by reference as per Idaho Air Rules Section 107.03.b.
- b. Micrograms per cubic meter.
- c. Incorporated into Idaho Air Rules by reference, as per Idaho Air Rules Section 107.
- d. The maximum 1st highest modeled value is always used for the significant impact analysis unless indicated otherwise. Modeled design values are calculated for each ambient air receptor.
- e. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.
- f. Not to be exceeded more than once per year on average over 3 years.
- g. Concentration at any modeled receptor when using five years of meteorological data.
- h. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.
- i. 3-year mean of the upper 98th percentile of the annual distribution of 24-hour concentrations.
- j. 5-year mean of the 8th highest modeled 24-hour concentrations at the modeled receptor for each year of meteorological data modeled. For the SIL analysis, the 5-year mean of the 1st highest modeled 24-hour impacts at the modeled receptor for each year.
- k. 3-year mean of annual concentration.
- l. 5-year mean of annual averages at the modeled receptor.
- m. Not to be exceeded more than once per year.
- n. Concentration at any modeled receptor.
- o. Interim SIL established by EPA policy memorandum.
- p. 3-year mean of the upper 99th percentile of the annual distribution of maximum daily 1-hour concentrations.
- q. 5-year mean of the 4th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of 1st highest modeled 1-hour impacts for each year is used.
- r. Not to be exceeded in any calendar year.
- s. 3-year mean of the upper 98th percentile of the annual distribution of maximum daily 1-hour concentrations.
- t. 5-year mean of the 8th highest daily 1-hour maximum modeled concentrations for each year of meteorological data modeled. For the significant impact analysis, the 5-year mean of maximum modeled 1-hour impacts for each year is used.
- u. 3-month rolling average.
- v. An annual emissions rate of 40 ton/year of VOCs is considered significant for O₃.
- w. Annual 4th highest daily maximum 8-hour concentration averaged over three years. The O₃ standard was revised (the notice was signed by the EPA Administrator on October 1, 2015) to 70 ppb. However, this standard will not be applicable for permitting purposes until it is incorporated by reference *sine die* into Idaho Air Rules.

Compliance with Idaho Air Rules Section 203.02 is generally demonstrated if: a) all modeled impacts of the SIL analysis are below the applicable SIL or other level determined to be inconsequential to NAAQS compliance; or b) modeled design values of the cumulative NAAQS impact analysis (modeling all emissions from the facility and co-contributing sources, and adding a background concentration) are less than applicable NAAQS at receptors where impacts from the proposed facility/modification exceeded the SIL or other identified level of consequence; or c) if the cumulative NAAQS analysis showed NAAQS violations,

the impact of proposed facility/modification to any modeled violation was inconsequential (typically assumed to be less than the established SIL) for that specific receptor and for the specific modeled time when the violation occurred.

2.5 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.

Permitting requirements for toxic air pollutants (TAPs) from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.

Per Idaho Air Rules Section 210, if the total project-wide emissions increase of any TAP associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

Idaho Air Rules Section 210.20 states that if TAP emissions from a specific source are regulated by the Department or EPA under 40 CFR 60, 61, or 63, then a TAP impact analysis under Section 210 is not required for that TAP.

3.0 Analytical Methods and Data

This section describes the methods and data used in analyses to demonstrate compliance with applicable air quality impact requirements.

3.1 Emission Source Data

Emissions rates of criteria pollutants and TAPs for the project were provided by the applicant for various applicable averaging periods. Review and approval of estimated emissions was the responsibility of the DEQ permit writer and is not addressed in this modeling memorandum. DEQ modeling review included verification that the application's potential emissions rates were properly used in the model. The rates listed must represent the maximum allowable rate as averaged over the specified period.

Emissions rates used in the dispersion modeling analyses submitted by IFG-Laclede should be reviewed by the DEQ permit writer against those in the emissions inventory of the permit application. All modeled

criteria air pollutant and TAP emissions rates should be equal to or greater than the facility's emissions calculated in other sections of the PTC application or requested permit allowable emission rates.

3.1.1 Criteria Pollutant Emissions Rates and Modeling Applicability

If facility-wide potential to emit (PTE) values, or project wide PTE in some instances, for a specific criteria pollutant would qualify for a below regulatory concern (BRC) permit exemption as per Idaho Air Rules Section 221 if it were not for some pollutants exceeding BRC thresholds, then an air impact analysis for that pollutant may not be required for permit issuance. DEQ's regulatory interpretation policy of exemption provisions of Idaho Air Rules (Policy on NAAQS Compliance Demonstration Requirements, DEQ policy memorandum, July 11, 2014) is that: "A DEQ NAAQS compliance assertion will not be made by the DEQ modeling group for specific criteria pollutants having a project emissions increase below BRC levels, provided the proposed project would have qualified for a Category I Exemption for BRC emissions quantities except for the emissions of another criteria pollutant." The interpretation policy also states that the exemption criteria of uncontrolled PTE not to exceed 100 ton/year (Idaho Air Rules Section 220.01.a.i) is not applicable when evaluating whether a NAAQS impact analyses is required. A permit will be issued limiting PTE below 100 ton/year, thereby negating the need to maintain calculated uncontrolled PTE under 100 ton/year.

DEQ has generated non-site-specific project modeling thresholds for those projects that cannot use the BRC exemption from an impact analysis (if there are specific permitted emissions limits that require changing, etc.). Modeling applicability thresholds are provided in the *Idaho Air Modeling Guideline*. These thresholds were based on assuring an ambient impact of less than established SIL for that specific pollutant and averaging period.

If project-specific total emissions rates are below Level I Modeling Thresholds, project-specific air impact analyses are not necessary for permitting. Use of level II modeling thresholds are conditional, requiring DEQ approval. Table 3 provides the emissions-based modeling applicability summary. BISON compared emission estimates with Level I Modeling Thresholds, and determined that modeling is necessary for the criteria pollutants listed in Table 3. Emissions as modeled per source in the final application submitted on January 4, 2017, are listed in Table 4.

An impact analysis must be performed for pollutant increases that would not qualify for the BRC exemption from an impact analysis. Emissions of all criteria pollutants except Lead from the proposed project exceeded BRC thresholds.

Table 3. MODELING APPLICABILITY ANALYSIS RESULTS						
Pollutant	Averaging Period	Emissions	BRC Threshold (ton/year)	Level I Modeling Thresholds (lb/hour or ton/year)	Level II Modeling Thresholds (lb/hour or ton/year)	Modeling Required
PM _{2.5}	Annual	21.23 ton/yr	1	0.350	4.1	Yes
	24-hour	4.85 lb/hr		0.054	0.63	Yes
PM ₁₀	24-hour	4.85 lb/hr	1.5 (0.34 lb/hr)	0.22	2.6	Yes
NO _x	Annual	172 ton/yr	4	1.2	14	Yes
	1-hour	39.3 lb/hr		0.2	2.4	Yes

Table 3. MODELING APPLICABILITY ANALYSIS RESULTS						
Pollutant	Averaging Period	Emissions	BRC Threshold (ton/year)	Level I Modeling Thresholds (lb/hour or ton/year)	Level II Modeling Thresholds (lb/hour or ton/year)	Modeling Required
SO ₂	Annual	14.34 ton/yr	4	1.2	14	Yes
	1-hour	3.3 lb/hr		0.21	2.5	Yes
CO	1-hr, 8-hr	39.3 ton/yr	10	15	175	Yes
Lead	Month	4.7 lb/month	1.5	14 lb/month		No

Ozone (O₃) differs from other criteria pollutants in that it is not typically emitted directly into the atmosphere. O₃ is formed in the atmosphere through reactions of VOCs, NO_x, and sunlight. Atmospheric dispersion models used in stationary source air permitting analyses (see Section 3.3.3) cannot be used to estimate O₃ impacts resulting from VOC and NO_x emissions from an industrial facility. O₃ concentrations resulting from area-wide emissions are predicted by using more complex airshed models such as the Community Multi-Scale Air Quality (CMAQ) modeling system. Use of the CMAQ model is very resource intensive and DEQ asserts that performing a CMAQ analysis for a particular permit application is not typically a reasonable or necessary requirement for air quality permitting.

Addressing secondary formation of O₃ has been somewhat addressed in EPA regulation and policy. As stated in a letter from Gina McCarthy of EPA to Robert Ukeiley, acting on behalf of the Sierra Club (letter from Gina McCarthy, Assistant Administrator, United States Environmental Protection Agency, to Robert Ukeiley, January 4, 2012):

... footnote 1 to sections 51.166(I)(5)(I) of the EPA's regulations says the following: "No de minimis air quality level is provided for ozone. However, any net emission increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of air quality data."

The EPA believes it unlikely a source emitting below these levels would contribute to such a violation of the 8-hour ozone NAAQS, but consultation with an EPA Regional Office should still be conducted in accordance with section 5.2.1.c. of Appendix W when reviewing an application for sources with emissions of these ozone precursors below 100 TPY."

Allowable emissions estimates of VOCs and NO_x are below the 100 tons/year threshold, and DEQ determined it was not appropriate or necessary to require a quantitative source specific O₃ impact analysis.

Table 4 provides criteria pollutant emissions rates used in the air impact SIL analyses. Table 5 lists criteria pollutant emissions for the entire facility inventory for those pollutants exceeding the SIL that are needed to demonstrate compliance with NAAQS. All criteria pollutants except lead were modeled in the NAAQS compliance analyses.

Table 4. MODELED EMISSION RATES FOR SIL ANALYSES						
Source ID	Source Description	CO (lb/hr)^a	NO₂ (lb/hr)^a	SO₂ (lb/hr)^a	PM₁₀ (lb/hr)^a	PM_{2.5} (lb/hr)^a
BOIL1	Existing Stoker Boiler	-46.35	-21.07	-1.76	-3.79	-3.79
BOIL2	Existing Stoker Boiler	-69.86	-20.30	-1.69	-3.66	-3.66
WELLONS	Proposed Wellons Fuel Cell Boiler	39.27	39.27	3.27	4.85	4.85

^a pounds/hour

Table 5. MODELED EMISSION RATES FOR NAAQS ANALYSES					
Source ID	Source Description	PM_{2.5} (lb/hr)^a	PM₁₀ (lb/hr)^a	NO₂ (lb/hr)^a	SO₂ (lb/hr)^a
WELLONS	Proposed Wellons Fuel Cell Boiler	4.8470	4.8470	39.27	3.27
EU3	Planar Chipper Cyclone	0.2100	0.4200		
EU4	Planar Shavings Baghouse	0.1110	0.1660		
EU5	Planar Shavings Baghouse	0.1110	0.1660		
EU6	Shavings Bin Vent Baghouse	0.0005	0.0007		
KA1	Lumber Dry Kilns	0.0187	0.0216		
KA2	Lumber Dry Kilns	0.0187	0.0216		
KA3	Lumber Dry Kilns	0.0187	0.0216		
KA4	Lumber Dry Kilns	0.0187	0.0216		
KA5	Lumber Dry Kilns	0.0187	0.0216		
KA6	Lumber Dry Kilns	0.0187	0.0216		
KA7	Lumber Dry Kilns	0.0187	0.0216		
KA8	Lumber Dry Kilns	0.0187	0.0216		
KB1	Lumber Dry Kilns	0.0187	0.0216		
KB2	Lumber Dry Kilns	0.0187	0.0216		
KB3	Lumber Dry Kilns	0.0187	0.0216		
KB4	Lumber Dry Kilns	0.0187	0.0216		
KB5	Lumber Dry Kilns	0.0187	0.0216		
KB6	Lumber Dry Kilns	0.0187	0.0216		
KB7	Lumber Dry Kilns	0.0187	0.0216		
KB8	Lumber Dry Kilns	0.0187	0.0216		
KC1	Lumber Dry Kilns	0.0187	0.0216		
KC2	Lumber Dry Kilns	0.0187	0.0216		
KC3	Lumber Dry Kilns	0.0187	0.0216		
KC4	Lumber Dry Kilns	0.0187	0.0216		
KC5	Lumber Dry Kilns	0.0187	0.0216		
KC6	Lumber Dry Kilns	0.0187	0.0216		
KC7	Lumber Dry Kilns	0.0187	0.0216		
KC8	Lumber Dry Kilns	0.0187	0.0216		
KD1	Lumber Dry Kilns	0.0187	0.0216		

Table 5. MODELED EMISSION RATES FOR NAAQS ANALYSES					
Source ID	Source Description	PM_{2.5} (lb/hr)^a	PM₁₀ (lb/hr)^a	NO₂ (lb/hr)^a	SO₂ (lb/hr)^a
KD2	Lumber Dry Kilns	0.0187	0.0216		
KD3	Lumber Dry Kilns	0.0187	0.0216		
KD4	Lumber Dry Kilns	0.0187	0.0216		
KD5	Lumber Dry Kilns	0.0187	0.0216		
KD6	Lumber Dry Kilns	0.0187	0.0216		
KD7	Lumber Dry Kilns	0.0187	0.0216		
KD8	Lumber Dry Kilns	0.0187	0.0216		
KE1	Lumber Dry Kilns	0.0187	0.0216		
KE2	Lumber Dry Kilns	0.0187	0.0216		
KE3	Lumber Dry Kilns	0.0187	0.0216		
KE4	Lumber Dry Kilns	0.0187	0.0216		
KE5	Lumber Dry Kilns	0.0187	0.0216		
KE6	Lumber Dry Kilns	0.0187	0.0216		
KE7	Lumber Dry Kilns	0.0187	0.0216		
KE8	Lumber Dry Kilns	0.0187	0.0216		
KF1	Lumber Dry Kilns	0.0187	0.0216		
KF2	Lumber Dry Kilns	0.0187	0.0216		
KF3	Lumber Dry Kilns	0.0187	0.0216		
KF4	Lumber Dry Kilns	0.0187	0.0216		
KF5	Lumber Dry Kilns	0.0187	0.0216		
KF6	Lumber Dry Kilns	0.0187	0.0216		
KF7	Lumber Dry Kilns	0.0187	0.0216		
KF8	Lumber Dry Kilns	0.0187	0.0216		
KG1	Lumber Dry Kilns	0.0187	0.0216		
KG2	Lumber Dry Kilns	0.0187	0.0216		
KG3	Lumber Dry Kilns	0.0187	0.0216		
KG4	Lumber Dry Kilns	0.0187	0.0216		
KG5	Lumber Dry Kilns	0.0187	0.0216		
KG6	Lumber Dry Kilns	0.0187	0.0216		
KG7	Lumber Dry Kilns	0.0187	0.0216		
KG8	Lumber Dry Kilns	0.0187	0.0216		
KH1	Lumber Dry Kilns	0.0187	0.0216		
KH2	Lumber Dry Kilns	0.0187	0.0216		
KH3	Lumber Dry Kilns	0.0187	0.0216		
KH4	Lumber Dry Kilns	0.0187	0.0216		
KH5	Lumber Dry Kilns	0.0187	0.0216		
KH6	Lumber Dry Kilns	0.0187	0.0216		
KH7	Lumber Dry Kilns	0.0187	0.0216		
KH8	Lumber Dry Kilns	0.0187	0.0216		

Table 5. MODELED EMISSION RATES FOR NAAQS ANALYSES					
Source ID	Source Description	PM_{2.5} (lb/hr)^a	PM₁₀ (lb/hr)^a	NO₂ (lb/hr)^a	SO₂ (lb/hr)^a
FIREPUMP	Emergency Firepump Engine	0.0202	0.0202		
Table 5. continued - VOLUME SOURCES		PM₁₀ (lb/hr)	PM_{2.5} (lb/hr)		
PF1	Debarker	0.0595	0.3360		
PF2	Bark Hog	0.0013	0.0072		
PF3	Sawmill Truck Bin Top Vent	0.0001	0.0004		
PF4	Chip Truck Bin Top Vent	0.0001	0.0007		
PF5	Sawdust Bin Truck Loadout	0.0001	0.0008		
PF6	Chip Bin Truck Loadout	0.0002	0.0014		
PF7	Planar Shavings Bin Truck Loadout & Planar Chips Loadout	0.0002	0.0015		

^a pounds/hour

Secondary Particulate Formation

The impact from secondary particulate formation resulting from emissions of NO_x, SO₂, and/or VOCs was assumed by DEQ to be negligible based on the magnitude of emissions and the short distance from emissions sources to modeled receptors where maximum PM₁₀ and PM_{2.5} impacts would be anticipated.

3.1.2 Toxic Air Pollutant Emissions Rates

TAP emissions regulations under Idaho Air Rules Section 220 are only applicable for new or modified sources constructed after July 1, 1995. As listed in Table 6, the submitted emissions inventory in the application identified no TAPs having potential emissions increases that could exceed screening emissions levels (ELs) of Idaho Air Rules Section 585 and 586. Detailed calculations of estimated TAP emissions are included in the permit application.

Table 6. TAP EMISSION CHANGES AND ELS			
Pollutant	Proposed Emission Change (lb/hr)	Screening Emissions Level (EL)^a (lb/hr)	Further Analysis Required?
Polyaromatic Hydrocarbons (except 7-PAH group)	-3.64E-05	9.15E-05	No
2-Butanone (MEK) - Removed from HAPS	-1.31E-03	39.3	No
Crotonaldehyde	-3.74E-05	0.38	No
Propionaldehyde	-6.85E-05	0.0287	No
Copper	-4.22E-04	0.067	No
Manganese	-3.62E-05	0.067	No
Molybdenum	-1.11E-02	0.667	No
Phosphorus	-1.45E-05	0.007	No
Silver	-2.26E-03	0.007	No
Tin	-1.18E-02	0.133	No
Vanadium	-1.59E-04	0.003	No

^a ELs from Idaho Air Rules Section 585 and 586 in pounds/hour.

3.1.3 Emission Release Parameters

Table 7 provides emissions release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocity for facility sources as used in the final modeling assessment.

Stack parameters used in the modeling analyses were adequately documented/justified in the application. Additional flow information regarding the baghouse/cyclone exhaust parameters were supplied by BISON upon request from DEQ. The information for the Emergency Fire Pump was also provided after the application submittal date.

Table 7. MODELING SOURCE PARAMETERS							
Point Sources							
Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Stack Height (ft)^c	Temperature (°F)^d	Exit Velocity (fps)^e	Stack Diameter (ft)^c
WELLONS	Proposed Wellons Fuel Cell Boiler	518045	5334761	79.6	336.0	63.800	4.2
EU3	Planar Chipper Cyclone	517980	5334886	37.0	-459.7	15.915 ^f	2.0
EU4	Planar Shavings Baghouse	517998	5334896	10.0	-459.7	48.599	4.1
EU5	Planar Shavings Baghouse	518004	5334952	45.0	-459.7	37.477 ^f	3.9
EU6	Shavings Bin Vent Baghouse	517971	5334884	40.0	-459.7	15.915	2.0
FIREPUMP	Emergency Fire Pump	517975	5334716	6.0	649.0	164/0 ^f	0.3
KA1	Lumber Dry Kilns	517855	5335018	26.5	220.0	7.764	2.3
KA2	Lumber Dry Kilns	517853	5335017	26.5	220.0	7.764	2.3
KA3	Lumber Dry Kilns	517850	5335015	26.5	220.0	7.764	2.3
KA4	Lumber Dry Kilns	517847	5335014	26.5	220.0	7.764	2.3
KA5	Lumber Dry Kilns	517844	5335013	26.5	220.0	7.764	2.3
KA6	Lumber Dry Kilns	517842	5335012	26.5	220.0	7.764	2.3
KA7	Lumber Dry Kilns	517839	5335010	26.5	220.0	7.764	2.3
KA8	Lumber Dry Kilns	517836	5335009	26.5	220.0	7.764	2.3
KB1	Lumber Dry Kilns	517859	5335010	26.5	220.0	7.764	2.3
KB2	Lumber Dry Kilns	517856	5335009	26.5	220.0	7.764	2.3
KB3	Lumber Dry Kilns	517854	5335008	26.5	220.0	7.764	2.3
KB4	Lumber Dry Kilns	517851	5335006	26.5	220.0	7.764	2.3
KB5	Lumber Dry Kilns	517848	5335005	26.5	220.0	7.764	2.3
KB6	Lumber Dry Kilns	517846	5335004	26.5	220.0	7.764	2.3
KB7	Lumber Dry Kilns	517843	5335003	26.5	220.0	7.764	2.3
KB8	Lumber Dry Kilns	517840	5335001	26.5	220.0	7.764	2.3
KC1	Lumber Dry Kilns	517863	5335003	26.5	220.0	7.764	2.3
KC2	Lumber Dry Kilns	517860	5335001	26.5	220.0	7.764	2.3
KC3	Lumber Dry Kilns	517858	5335000	26.5	220.0	7.764	2.3
KC4	Lumber Dry Kilns	517855	5334999	26.5	220.0	7.764	2.3

Table 7. MODELING SOURCE PARAMETERS**Point Sources**

Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Stack Height (ft)^c	Temperature (°F)^d	Exit Velocity (fps)^e	Stack Diameter (ft)^c
KC5	Lumber Dry Kilns	517852	5334998	26.5	220.0	7.764	2.3
KC6	Lumber Dry Kilns	517850	5334996	26.5	220.0	7.764	2.3
KC7	Lumber Dry Kilns	517847	5334995	26.5	220.0	7.764	2.3
KC8	Lumber Dry Kilns	517844	5334994	26.5	220.0	7.764	2.3
KD1	Lumber Dry Kilns	517867	5334995	26.5	220.0	7.764	2.3
KD2	Lumber Dry Kilns	517864	5334994	26.5	220.0	7.764	2.3
KD3	Lumber Dry Kilns	517862	5334993	26.5	220.0	7.764	2.3
KD4	Lumber Dry Kilns	517859	5334991	26.5	220.0	7.764	2.3
KD5	Lumber Dry Kilns	517856	5334990	26.5	220.0	7.764	2.3
KD6	Lumber Dry Kilns	517854	5334989	26.5	220.0	7.764	2.3
KD7	Lumber Dry Kilns	517851	5334987	26.5	220.0	7.764	2.3
KD8	Lumber Dry Kilns	517848	5334986	26.5	220.0	7.764	2.3
KE1	Lumber Dry Kilns	517871	5334987	26.5	220.0	7.764	2.3
KE2	Lumber Dry Kilns	517868	5334986	26.5	220.0	7.764	2.3
KE3	Lumber Dry Kilns	517866	5334985	26.5	220.0	7.764	2.3
KE4	Lumber Dry Kilns	517863	5334984	26.5	220.0	7.764	2.3
KE5	Lumber Dry Kilns	517860	5334982	26.5	220.0	7.764	2.3
KE6	Lumber Dry Kilns	517857	5334981	26.5	220.0	7.764	2.3
KE7	Lumber Dry Kilns	517855	5334980	26.5	220.0	7.764	2.3
KE8	Lumber Dry Kilns	517852	5334978	26.5	220.0	7.764	2.3
KF1	Lumber Dry Kilns	517875	5334980	26.5	220.0	7.764	2.3
KF2	Lumber Dry Kilns	517872	5334979	26.5	220.0	7.764	2.3
KF3	Lumber Dry Kilns	517870	5334977	26.5	220.0	7.764	2.3
KF4	Lumber Dry Kilns	517867	5334976	26.5	220.0	7.764	2.3
KF5	Lumber Dry Kilns	517864	5334975	26.5	220.0	7.764	2.3
KF6	Lumber Dry Kilns	517861	5334973	26.5	220.0	7.764	2.3
KF7	Lumber Dry Kilns	517859	5334972	26.5	220.0	7.764	2.3
KF8	Lumber Dry Kilns	517856	5334971	26.5	220.0	7.764	2.3
KG1	Lumber Dry Kilns	517879	5334972	26.5	220.0	7.764	2.3
KG2	Lumber Dry Kilns	517876	5334971	26.5	220.0	7.764	2.3
KG3	Lumber Dry Kilns	517873	5334970	26.5	220.0	7.764	2.3
KG4	Lumber Dry Kilns	517871	5334968	26.5	220.0	7.764	2.3
KG5	Lumber Dry Kilns	517868	5334967	26.5	220.0	7.764	2.3
KG6	Lumber Dry Kilns	517865	5334966	26.5	220.0	7.764	2.3
KG7	Lumber Dry Kilns	517863	5334964	26.5	220.0	7.764	2.3
KG8	Lumber Dry Kilns	517860	5334963	26.5	220.0	7.764	2.3
KH1	Lumber Dry Kilns	517883	5334965	26.5	220.0	7.764	2.3
KH2	Lumber Dry Kilns	517880	5334963	26.5	220.0	7.764	2.3

Table 7. MODELING SOURCE PARAMETERS							
Point Sources							
Source ID	Source Description	Easting (X) (m)	Northing (Y) (m)	Stack Height (ft)^c	Temperature (°F)^d	Exit Velocity (fps)^e	Stack Diameter (ft)^c
KH3	Lumber Dry Kilns	517877	5334962	26.5	220.0	7.764	2.3
KH4	Lumber Dry Kilns	517875	5334961	26.5	220.0	7.764	2.3
KH5	Lumber Dry Kilns	517872	5334959	26.5	220.0	7.764	2.3
KH6	Lumber Dry Kilns	517869	5334958	26.5	220.0	7.764	2.3
KH7	Lumber Dry Kilns	517867	5334957	26.5	220.0	7.764	2.3
KH8	Lumber Dry Kilns	517864	5334955	26.5	220.0	7.764	2.3

Table 7 Modeling Source Parameters – cont.						
Volume Sources						
Source ID	Description	Easting (X)^a (m)	Northing (Y)^b (m)	Release Height (ft)^c	Init. Horizontal Dimension (ft)^c	Initial Vert. Dimension (ft)^c
PF1	Debarker	517750	5334787	18.0	7.8	16.7
PF2	Bark Hog	517763	5334784	10.0	1.9	16.7
PF3	Sawmill Truck Bin Top Vent	517897	5334750	37.0	0.7	17.2
PF4	Chip Truck Bin Top Vent	517894	5334760	37.0	0.7	17.2
PF5	Sawdust Bin Truck Loadout	517897	5334750	9.0	11.6	8.4
PF6	Chip Bin Truck Loadout	517894	5334760	9.0	11.6	8.4
PF7	Planer Shaving Bin Truck/Planer Chips	517975	5334885	9.0	11.6	8.4

a. Universal Transverse Mercator coordinates in meters (m) in the east/west direction.

b. Universal Transverse Mercator coordinates in meters in the north/south direction.

c. Feet.

d. Degrees Fahrenheit.

e. Feet per second.

f. Modeled as a horizontal release

3.2 Background Concentrations

Background concentrations were obtained from the NW AirQuest Consortium website, as recommended by DEQ. These values are listed in Table 10, Results for NAAQS Modeling.

3.3 Impact Modeling Methodology

This section describes the modeling methods used by the applicant to demonstrate preconstruction compliance with applicable air quality standards.

3.3.1 General Overview of Analyses

BISON performed project-specific air impact analyses that were determined by DEQ to be reasonably representative of the proposed facility as described in the application. Results of the submitted analyses demonstrate compliance with applicable air quality standards to DEQ's satisfaction, provided the facility is operated as described in the submitted application and in this memorandum.

Table 8 provides a brief description of parameters used in the modeling analyses.

Table 8. MODELING PARAMETERS		
Parameter	Description/Values	Documentation/Addition Description
General Facility Location	Laclede, Idaho	The facility is located in an area that is attainment or unclassified for all criteria air pollutants
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 15181.
Meteorological Data	2011-2015 Sandpoint, Idaho surface data, and upper air data from Spokane, WA	The meteorological model input files for this project were provided by and recommended as most representative for this project by IDEQ, as described in the IDEQ modeling protocol and verified by IDEQ's approval of that protocol.
Terrain	Considered	See section 5.3 below
Building Downwash	Considered	Because there are substantial buildings at the facility, BPIP-PRIME was used to evaluate building dimensions for consideration of downwash effects in AERMOD.
Receptor Grid	Grid 1	25-meter spacing along the ambient air boundary and 10-meter spacing in areas of high impacts
	Grid 2	50-meter spacing in areas of public access and out to distances of 2500+ meters with respect to the facility
	Grid 3	100-meter spacing out to approximately 6,500 meters
	Grid 4	500-meter spacing out to 10,500 meters

3.3.2 Modeling protocol and Methodology

A modeling protocol was submitted on November 10, 2016. The protocol was conditionally approved on December 16, 2016. Included in these conditions was the request to use an updated meteorological data set for the period 2011-2015 (provided by DEQ), and specification of ambient background concentration values taken from NWAIRQUEST. The permit application was submitted on January 4, 2017, and was determined to be complete on February 2, 2017. Several issues with the modeling analyses were addressed after the completeness date. These included omission in the source inventory of an existing emergency fire pump engine and increased documentation of exhaust flow parameters for the baghouse/cyclone sources. The applicant responded with a revised source inventory and modeling files which included the emergency fire pump engine on February 16, 2017. These files showed little increase from the submitted application results, and showed no exceedances of NAAQS for all criteria pollutants. On February 18, 2017, the applicant provided additional information on the derivation of exhaust flows from the baghouse and cyclone sources, which satisfied DEQ's request.

Project-specific modeling and other required impact analyses were generally conducted using data and methods discussed in pre-application correspondence and in the *Idaho Air Quality Modeling Guideline*¹.

3.3.3 Model Selection

Idaho Air Rules Section 202.02 requires that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state,

multiple source Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD version 15181 was used by the applicant for the air impact modeling analyses to evaluate impacts of the facility. This version was the current version at the time the application was received by DEQ.

3.3.4 Meteorological Data

BISON used meteorological data supplied by DEQ. This data was collected at the Sandpoint, Idaho, airport for the period 2011-2015. Upper air data was collected from the Spokane, Washington airport. DEQ determined the data as used in the submitted analyses is adequately representative for minor source modeling in the locale of Laclede, Idaho.

3.3.5 Effects of Terrain on Modeled Impacts

Terrain data were extracted from United States Geological Survey (USGS) National Elevation Dataset (NED) files in the WGS84 datum (approximately equal to the NAD83 datum). NWRC used 1 Arc Second resolution data, which is adequate for this analysis.

The terrain preprocessor AERMAP Version 11103 was used to extract the elevations from the NED files and assign them to receptors in the modeling domain in a format usable by AERMOD. AERMAP also determined the hill-height scale for each receptor. The hill-height scale is an elevation value based on the surrounding terrain which has the greatest effect on that individual receptor. AERMOD uses those heights to evaluate whether the emissions plume has sufficient energy to travel up and over the terrain or if the plume will travel around the terrain.

DEQ reviewed the area surrounding the facility by using the web-based mapping program Google Earth, which uses the WGS84 datum. DEQ also overlaid modeling files with a digital photograph background images acquired from the 2013 ARCGIS NAIP (National Agriculture Imagery Program) data base. Elevations in the modeling domain matched those indicated by the background images

3.3.6 Facility Layout

DEQ compared the facility layout used in the model to that indicated in aerial photographs on Google Earth. The modeled layout was consistent with aerial photographs in Google Earth as well as from those in the ARCGIS 2013 NAIP database.

3.3.7 Effects of Building Downwash on Modeled Impacts

Potential downwash effects on emissions plumes are usually accounted for in the model by using building dimensions and locations (locations of building corners, base elevation, and building heights). Dimensions and orientation of proposed buildings were needed as input to the Building Profile Input Program for the Plume Rise Model Enhancements downwash algorithm (BPIP-PRIME) because there are existing structures affecting the emissions plumes at the facility.

3.3.8 Ambient Air Boundary

Ambient air is defined in Section 006 of the Idaho Air Rules as “that portion of the atmosphere, external to

buildings, to which the general public has access.” For the modeling analyses, the boundary has been defined as the main mill site. Public access is precluded through management and physical barriers, including fencing.

3.3.9 Receptor Network

Table 8 describes the receptor grid used in the submitted analyses. The receptor grid met the minimum recommendations specified in the *Idaho Air Quality Modeling Guideline*¹. DEQ determined this grid assured maximum impacts were reasonably resolved by the model considering: 1) types of sources modeled; 2) modeled impacts and the modeled concentration gradient; 3) conservatism of the methods and data used as inputs to the analyses; 4) potential for continual exposures or exposure to sensitive receptors. Additionally, DEQ performed sensitivity analyses using a finer grid spaced receptor network to assure that maximum concentrations were below all applicable standards.

3.3.10 Good Engineering Practice Stack Height

An allowable good engineering practice (GEP) stack height may be established using the following equation in accordance with Idaho Air Rules Section 512.03.b:

$H = S + 1.5L$, where:

H = good engineering practice stack height measured from the ground-level elevation at the base of the stack.

S = height of the nearby structure(s) measured from the ground-level elevation at the base of the stack.

L = lesser dimension, height or projected width, of the nearby structure.

Buildings exist in the vicinity for all point sources modeled. Therefore, consideration of downwash caused by nearby buildings was required.

4.0 Impact Modeling Results

4.1 Results for Significant and NAAQS Impact Level Analyses

BISON performed air quality modeling for those criteria pollutants having emissions exceeding Level I modeling thresholds (PM₁₀, PM_{2.5}, CO, SO₂, and NO₂). The results from the Significant Impact Level (SIL) Analyses for these pollutants are listed in Table 9 and show maximum predicted impacts are above the SILs for all criteria pollutants except CO. Therefore, modeling was required to demonstrate compliance with all NAAQS. Table 10 lists the results for these analyses, which shows compliance with all NAAQS.

Table 9. RESULTS FOR THE SIGNIFICANT IMPACT LEVEL ANALYSES					
Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)^a	Significant Contribution Level (SIL) ($\mu\text{g}/\text{m}^3$)	Percentage of Significant Contribution Level	Cumulative NAAQS Analysis Required
PM _{2.5} ^b	24-hour	5.75 ^g	1.2	479%	Yes
	Annual	0.026 ^g	0.3	9%	No
PM ₁₀ ^c	24-hour	11.0	5.0	221%	Yes
NO ₂ ^d	1-hour	182 ^g	7.5	2423%	Yes
	Annual	1.06	1.0	106%	Yes
SO ₂ ^e	1-hour	15.2 ^g	7.8	195%	Yes
	3-hour	10.9	25	43%	No
	24-hour	7.47	5.0	149%	Yes
	Annual	0.09	1.0	9%	No
CO ^f	1-hour	168	2,000	8%	No
	8-hour	117	500	23%	No

a. Micrograms/cubic meter

b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

d. Nitrogen dioxide.

e. Sulfur dioxide.

f. Carbon Monoxide.

g. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of highest modeled concentrations for each year modeled.

Table 10. RESULTS FOR CUMULATIVE NAAQS IMPACT ANALYSES					
Pollutant	Averaging Period	Modeled Design Concentration ($\mu\text{g}/\text{m}^3$)^a	Background Concentration ($\mu\text{g}/\text{m}^3$)	Total Impact ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)
PM _{2.5} ^b	24-hour	17.5 ^f	13	30.4 ^f	35
PM ₁₀ ^c	24-hour	45.9 ^g	75	121 ^g	150
NO ₂ ^d	1-hour	151 ^f	14.7	166 ^f	188
	1-hour, hotspot	168 ^f	14.7	183 ^f	188
	Annual	2.34	2.45	4.79	100
SO ₂ ^e	1-hour	17.0 ^h	2.9	19.9 ^h	196
	24-hour	4.43 ⁱ	1.8	6.30 ⁱ	365

a. Micrograms/cubic meter

b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

c. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers.

d. Nitrogen dioxide. 1-hour Background is 7.8 ppb, equal to 14.7 $\mu\text{g}/\text{m}^3$ and annual background is 1.3 ppb equal to 2.45 $\mu\text{g}/\text{m}^3$.

e. Sulfur Dioxide.

f. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of 8th highest modeled concentrations for each year modeled.

g. Maximum of 6th highest modeled concentrations for a 5-year period (or the maximum of the 2nd highest modeled concentrations if only 1 year of meteorological data are modeled).

h. Maximum of 5-year means (or a lesser averaging period if less than 5 years of meteorological data were used in the analyses) of 4th highest modeled concentrations for each year modeled.

i. Maximum of 2nd highest modeled concentrations for each year modeled.

4.2 *Results for TAPs Impact Analyses*

Dispersion modeling is required to demonstrate compliance with TAP increments specified by Idaho Air Rules Section 585 and 586 for those TAPs with project-specific emission increases exceeding emissions screening levels (ELs). Because there are no TAPs emissions that exceed the ELs, modeling analyses was not needed to demonstrate compliance with those AACs and AACCs.

5.0 Conclusions

The ambient air impact analyses and other air quality analyses submitted with the PTC application demonstrated to DEQ's satisfaction that emissions from the IFG-Laclede project will not cause or significantly contribute to a violation of any ambient air quality standard.

References:

1. *State of Idaho Guideline for Performing Air Quality Impact Analyses*. Idaho Department of Environmental Quality. September 2013. State of Idaho DEQ Air Doc. ID AQ-011. Available at <http://www.deq.idaho.gov/media/1029/modeling-guideline.pdf>.
2. Air Quality Environmental Science and Technology Consortium (NW AIRQUEST). *Lookup 2009-2011 Design Values of Criteria Pollutants*. Available at: <http://lar.wsu.edu/nw-airquest/lookup.html>.

APPENDIX C – FACILITY DRAFT COMMENTS

The following comments were received from the facility on April 10 and April 17, 2017:

Facility Comment: IFG has reviewed the Facility Draft PTC for the Wellons boiler at Laclede. We filled in the information on Table 1.1. On Table 1.1 and in Section 2.1, the description of the Wellons boiler has been changed to exclude the superheater. IFG does not plan to install the superheater (and desuperheater) at Laclede because they don't plan to use a steam turbine. The boiler will be used to heat the kilns, which requires saturated steam not superheated steam.

The boiler's maximum heat input capacity is unchanged. The design heat input capacity of 131 MMBtu/hr has been used as applicable for the emissions calculations used in the permit. Without the super-heater, the boiler will likely not be used at maximum heat input capacity.

The maximum boiler steam production rate is unchanged; it is 80,000 pounds mass of steam per hour (lb steam/hr).

The boiler produces saturated steam. If the super-heater were used, it would add more heat to the steam to raise its temperature beyond the point of saturation. Without the super-heater, the boiler will use the amount of heat needed to produce the amount of saturated steam at the pressured needed for the kilns. The relationship between heat input and steam production is show below. Variations in saturated steam pressure have little effect on the heat value.

Heat value of saturated steam at 125 psia: 1,191 Btu/lb steam

Estimated boiler efficiency: 75%

Estimated heat input: $80,000 \text{ lb steam/hr} * 1,191 \text{ Btu/lb steam} / (75\%) = 127 \text{ MMBtu/hr}$

The Wellons Boiler (EU1) stack parameters for the PTC application were taken from the 2006 source test on the boiler at its current location, as described in Attachment D1 to the modeling report in Appendix D of the PTC application. The summary of the 2006 source test is included with Attachment D1. It shows that the boiler was operated at a heat input rate of 123.6 MMBtu/hr during the source test. Therefore, the modeled source parameters are representative of the boiler operating with or without the super-heater.

DEQ Response: the permit is revised to reflect that no superheater would be installed.

Facility Comment: In Section 2.5, the facility is requesting clarification that the steaming limit is a 1-hour average limit, not an instantaneous limit.

DEQ Response: The request change is made.

Facility Comment: In Section 3.1, the kilns should be described as being six kilns, not four kilns. The kiln modeling outcome is not affected because the full kiln emission was modeled using a large number of point sources spread over the full kiln area. The full width of the kiln-bank was used for the downwash calculation.

DEQ Response: The changes are made in the permit.

Facility Comment: The header for Section 3.5 has an extra letter, and in Section 3.6 '11-month' should be '12-month'. As you noted, the description of the sawdust and chip conveyors has been changed from pneumatic conveying to mechanical conveying, and there are not target boxes.

DEQ Response: the corrections are made.

APPENDIX D – PROCESSING FEE

N	Does this facility qualify for a general permit (i.e. concretebatch 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	Pre-project PTE (T/yr)	Post project PTE (T/yr)	Annual Emissions Change (T/yr)
NO _x	181.57	172.48	-9.09
SO ₂	15.12	14.37	-0.76
CO	509.07	172.21	-336.87
PM10	43.24	31.84	-11.40
VOC	195.59	248.41	52.82
TAPS/HAPS	42.90	43.29	0.39
Total:	987.49	682.59	-304.90
Fee Due	1,000.00		

APPENDIX E.1 – REGULATORY ANALYSIS – 40 CFR SUBPART DB

Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (2017AAG573)

**REGULATORY ANALYSIS FOR ATTACHMENT TO FORM FRA
e-CFR Data is current as of December 22, 2016**

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

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

Contents

§60.40b Applicability and delegation of authority.
§60.41b Definitions.
§60.42b Standard for sulfur dioxide (SO₂).
§60.43b Standard for particulate matter (PM).
§60.44b Standard for nitrogen oxides (NO_x).
§60.45b Compliance and performance test methods and procedures for sulfur dioxide.
§60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides.
§60.47b Emission monitoring for sulfur dioxide.
§60.48b Emission monitoring for particulate matter and nitrogen oxides.
§60.49b Reporting and recordkeeping requirements.

§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 input capacity greater than 100 MMBtu/h. 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...

Does not apply to the Wellons boiler, which was built 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 SO₂ standards under subpart J or subpart Ja of this part, as applicable.

NA

(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. NA

(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. NA

(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. NA

(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). [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. [NA](#)

(i) Affected facilities (*i.e.*, heat recovery steam generators) that are associated with stationary combustion turbines ... [NA](#)

(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). [NA](#)

(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. [NA](#)

(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 SO₂ and NO_x standards under this subpart and the PM standards under subpart BB. [NA](#)

(m) Temporary boilers are not subject to this subpart. [NA](#)

§60.41b Definitions. [Noted](#)

§60.42b Standard for sulfur dioxide (SO₂).

(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 SO₂ in excess of 87 ng/J (0.20 lb/MMBtu) or 10 percent (0.10) of the potential SO₂ emission rate (90 percent reduction) ...

[The SO₂ standard does not apply to the Wellons boiler because it does not burn 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: [NA](#)

(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 SO₂ 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. [NA](#)

(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.

The Wellons boiler was issued a permit authorizing construction at the former location in Warm Springs, Oregon on May 4, 2005. The boiler was authorized to startup on December 27, 2005. Therefore, the date on which it commenced construction is set as May 4, 2005. The applicable emission limit for PM is 0.030 lb/MMBtu as per (h)(1).

(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: NA

(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. Noted. 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 is subject to a federally enforceable PM limit of <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. Noted

(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,

Paragraph (h)(3) applies to the Wellons boiler.

(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: (i) 22 ng/J (0.051 lb/MMBtu) heat input derived from the combustion of coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels; and (ii) 0.2 percent of the combustion concentration (99.8 percent reduction) when combusting coal, oil, wood, a mixture of these fuels, or a mixture of these fuels with any other fuels.

This alternative conflicts with Boiler MACT, so is not an option for the Wellons boiler.

(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 131 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. NA

(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 ... NA

(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 ... NA

§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 NO₂) in excess of the following emission limits:

NA. The Wellons boiler only combusts wood.

(b) 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 simultaneously combusts mixtures of only coal, oil, or natural gas ... NA. The Wellons boiler only combusts wood.

(c) Except as provided under paragraph (d) 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 simultaneously combusts coal or oil, natural gas (or any combination of the three), and wood, or any other fuel shall cause to be discharged into the atmosphere any gases that contain NO_x in excess of the emission limit for the coal, oil, natural gas (or any combination of the three), ... NA. The Wellons boiler only combusts wood.

(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 simultaneously combusts natural gas and/or distillate oil ... NA. The Wellons boiler only combusts wood.

(e) Except as provided under paragraph (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 simultaneously combusts only coal, oil, or natural gas with byproduct/waste ... **NA. The Wellons boiler only combusts wood.**

(f) Any owner or operator of an affected facility that combusts byproduct/waste with either natural gas or oil ... **NA. The Wellons boiler only combusts wood.**

(g) Any owner or operator of an affected facility that combusts hazardous waste (... **NA. The Wellons boiler only combusts wood.**

(h) For purposes of paragraph (i) of this section, the NO_x standards under this section apply at all times including periods of startup, shutdown, or malfunction.

NA. The Wellons boiler is not subject to a NOX standard.

(i) Except as provided under paragraph (j) of this section, compliance with the emission limits under this section is determined on a 30-day rolling average basis.

NA. The Wellons boiler is not subject to a NOX standard.

(j) Compliance with the emission limits under this section is determined on a 24-hour average basis for the initial performance test and on a 3-hour average basis for subsequent performance tests for any affected facilities that:

NA. The Wellons boiler is not subject to a NOX standard.

- (1) Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30 weight percent or less;
- (2) Have a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less; and
- (3) Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30 weight percent or less and limiting operation of the affected facility to a combined annual capacity factor of 10 percent or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30 weight percent or less.

(k) Affected facilities that meet the criteria described in paragraphs (j)(1), (2), and (3) of this section, and that have a heat input capacity of 73 MW (250 MMBtu/hr) or less, are not subject to the NO_x emission limits under this section.

The Wellons Boiler meets the criteria of (j)(2). It has a combined annual capacity factor of 0% for non-wood fuels. The Wellons boiler is not subject to the NOx emission limits under this section.

(l) On and after the date on which the initial performance test is completed or is required to be completed under 60.8, whichever date is first... **NA. The Wellons boiler is not subject to a NOX standard.**

§60.45b Compliance and performance test methods and procedures for sulfur dioxide.

NA. The Wellons boiler is not subject to an SO₂ standard.

§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. **Noted**

(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. [Noted](#)

(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. [NA](#)

(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:

(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. [Applies to the Wellons boiler](#)

(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; [Applies to the Wellons boiler](#)

(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. [Applies to the Wellons boiler](#)

(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). [Applies to the Wellons boiler](#)

(5) For determination of PM emissions, the oxygen (O₂) or CO₂ 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. [Applies to the Wellons boiler](#)

(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: (i) The O₂ or CO₂ 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. [Applies to the Wellons boiler](#)

(7) Method 9 of appendix A of this part is used for determining the opacity of stack emissions. [Applies to the Wellons boiler](#)

(e) To determine compliance with the emission limits for NO_x ... [NA. The Wellons boiler is not subject to any NO_x limit.](#)

(f) To determine compliance with the emissions limits for NO_x ... [NA. The Wellons boiler is not subject to any NO_x limit.](#)

(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.

~~IFG will make the required demonstration of maximum heat input capacity for the Wellons boiler.~~

(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: **NA**

(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). **NA**

(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.

NA. IFG does not intend to install a continuous PM monitor.

§60.47b Emission monitoring for sulfur dioxide.

NA. The Wellons boiler is not subject to an SO₂ 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.

(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.

IFG will comply with all applicable opacity monitoring requirements including installation and operation of a COMS.

(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. **NA. The Wellons boiler is not subject to a NO_x limit.**

(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. **NA. The Wellons boiler is not subject to a NO_x limit.**

(d) The 1-hour average NO_x emission rates measured by the continuous NO_x monitor **NA. The Wellons boiler is not subject to a NO_x limit.**

(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 will comply 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: ... *NA. The Wellons boiler is not subject to a NO_x limit.*

(f) When NO_x emission data are not obtained because of CEMS breakdowns, ... *NA. The Wellons boiler is not subject to a NO_x limit.*

(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: ... *NA. The Wellons boiler only burns wood.*

(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. *NA. The Wellons boiler is not subject to a NO_x limit.*

(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. *NA. The Wellons boiler is not subject to a NO_x limit.*

(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:

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, ...

NA. IFG does not intend to use a PM CEMS.

(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 ...

NA. The Wellons boiler only burns wood.

§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: *Applies 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; *Applies 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); *NA*

(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 *Applies to the Wellons boiler.*

(4) Notification that an emerging technology will be used for controlling emissions of SO₂. ... NA

(b) The owner or operator of each affected facility subject to the SO₂, 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.

Applies to the Wellons boiler, IFG will comply.

(c) The owner or operator of each affected facility subject to the NO_x standard in §60.44b ...

NA. The Wellons boiler is not subject to a 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.

(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. Applies to the Wellons boiler.

(e) For an affected facility that combusts residual oil ... NA.

(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;

(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. IFG does not plan to use Method 22 for opacity compliance from 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 ... **NA**.

(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. ... **IFG will comply**.

(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, ... **NA**.

(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), ... **NA**.

(i) The owner or operator of any affected facility subject to the continuous monitoring requirements for NO_x ... **NA**.

(j) The owner or operator of any affected facility subject to the SO₂ standards ... **NA**

(k) For each affected facility subject to the compliance and performance testing requirements of §60.45b ... **NA**

(l) For each affected facility subject to the compliance and performance testing requirements of §60.45b(d) ... **NA**

(m) For each affected facility subject to the SO₂ ... **NA**

(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, ... **NA**

(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. **IFG will comply**.

(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: **Does not apply as the boiler is not subject to NO_x standard and is not an affected facility described in §60.44b(j) or (k)**.

- (1) Calendar date;
- (2) The number of hours of operation; and
- (3) A record of the hourly steam load.

(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: **Does not apply as the boiler is not subject to NO_x standard and is not an affected facility described in §60.44b(j) or (k)**.

- (1) The annual capacity factor over the previous 12 months; **NA**
- (2) The average fuel nitrogen content during the reporting period, if residual oil was fired; **NA**
- (3) If the affected facility meets the criteria described in §60.44b(j), the results of any NO_x ... **NA**

(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: **NA**

(s) Facility specific NO_x standard for Cytec Industries ... **NA**.

(t) Facility-specific NO_x standard for Rohm and Haas Kentucky Incorporated's Boiler ... **NA**.

(u) *Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia.* ... [NA](#).

(v) The owner or operator of an affected facility may submit electronic quarterly reports for SO₂ 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.

(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 will comply](#).

(x) Facility-specific NO_x standard for Weyerhaeuser Company's No. 2 Power Boiler ... [NA](#).

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

APPENDIX E.2 – REGULATORY ANALYSIS – 40 CFR 63 SUBPART DDDDD

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (2017AAG572)

What This Subpart Covers

§63.7480 What is the purpose of this subpart?

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

§63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in §63.7575 that is located at, or is part of, a major source of HAP, except as specified in §63.7491. For purposes of this subpart, a major source of HAP is as defined in §63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in §63.7575. [78 FR 7162, Jan. 31, 2013]. IFG Laclede is subject to NESHAPS Subpart DDDDD because it is a major source of HAPS.

§63.7490 What is the affected source of this subpart?

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

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

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

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

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

(d) A boiler or process heater is existing if it is not new or reconstructed. The Wellons boiler is not new because it was constructed before June 4, 2010. It is not reconstructed because it has not been re-built, it is just being moved from one place to another. Idaho DEQ has assisted with this regulatory determination. The proposed Wellons boiler is an existing fuel cell boiler for purposes of Subpart DDDDD.

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

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

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

This section is not clear regarding an existing boiler that is being moved to a new location. If the Wellons were a new or reconstructed boiler, §63.7496(a) would apply, and IFG would have to comply upon startup. If the Wellons were an existing boiler, IFG would have had to comply by the compliance date as per §63.7496(b), but the Wellons wasn't even onsite by the compliance date.

(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.

(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).

In practice, the Wellons is expected to be in compliance with all emission limits and operating limits because of its design. IFG will follow the applicable work practices standards listed in Table 3 immediately upon startup. Idaho DEQ typically requires source testing of an added source (new or used equipment) within 180 days, which would comply with the boiler MACT requirements for new or existing sources.

Emission Limitations and Work Practice Standards

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

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

(g) Fuel cells designed to burn biomass/bio-based solid. The Wellons boiler is a fuel cell designed to burn biomass/bio-based solid.

§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. IFG will comply with the applicable emission limits and work practice standards for the Wellons boiler. The specific limits are identified in the tables at the end of this FRA analysis.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. IFG will comply with the applicable operating limits for the Wellons boiler. The specific limits are identified in the tables at the end of this FRA analysis.

(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. IFG will operate the boiler and emission controls as required.

(b) As provided in §63.6(g), EPA may approve use of an alternative to the work practice standards in this section. IFG does not anticipate requesting approval of any alternatives to the work practice standards.

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in §63.7540. 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 ... NA

(e) Boilers and process heaters in the units designed to burn gas 1 fuels ... NA

(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. Noted.

General Compliance Requirements

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

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

(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. IFG will do the required source testing or fuel analysis.

(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). IFG will develop the required site-specific monitoring plan for the equipment used for compliance monitoring.

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

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

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

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

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

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

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

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

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

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

(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. IFG will make a decision about which definition of startup to follow for the Wellons boiler, and will write an SSP if needed..

Testing, Fuel Analyses, and Initial Compliance Requirements

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

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

- (1) Conduct performance tests according to §63.7520 and Table 5 to this subpart.
- (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.
- (3) Establish operating limits according to §63.7530 and Table 7 to this subpart.
- (4) Conduct CMS performance evaluations according to §63.7525.

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. If IFG chooses 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. 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. 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.

The Wellons is a newly installed existing affected source. IFG feels that the language in paragraph (j) of this section is most applicable for this source.

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

IFG will treat the startup of the Wellons boiler as a re-start and will plan to perform compliance testing within 180 days of startup and the tune-up within 30 days after startup. The one-time energy assessment can't be completed unless the boiler is operating, so it will have to be done after startup.

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

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

IFG will perform performance tests each of the first two years after the Wellons start-up.

(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. IFG plans to complete subsequent performance tests on the modified schedule if allowed.

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. 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). Noted.

(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. The initial tune-up for the Wellons boiler is required 13 months after startup.

(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. 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. IFG will submit the performance test reports within the required timeframe.

§63.7520 What stack tests and procedures must I use?

IFG will follow all the performance testing requirements as described in this section. The exact requirements will be taken directly from the regulation.

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

IFG does not intend to use fuel analyses to demonstrate compliance. If this plan changes, IFG will follow the requirements of this section.

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

(a) As an alternative to meeting the requirements of §63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, IFG Laclede will not have more than one boiler after the Wellons boiler is installed so emissions averaging will not be an issue.

§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 (CO₂)) according to the procedures in paragraphs (a)(1) through (6) of this section. 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.

(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. IFG plans to install and operate an oxygen trim system and will set the oxygen level as required.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory ... NA

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

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

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

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

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

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

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

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

IFG plans to install and operate a COMS on the Wellons boiler stack as required in this section. The exact requirements will be taken directly from the regulation.

(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.

(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.

This applies to oxygen monitor.

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

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

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

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

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

This applies to steam flow monitor.

(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. ...NA

(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. ...NA

(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. The Wellons boiler will have an ESP, but not a wet scrubber, so this section does not apply.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate ...NA

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system ...NA

(k) For each unit that meets the definition of limited-use boiler or process heater...NA

(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, ...NA

(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 ...NA

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

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

(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). IFG will meet the requirements of this section.

(b)(4)(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.

(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.

IFG does not plan to use fuel analysis.

(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. Does not apply.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to items 5 and 6 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO₂ CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater: Does not apply.

§63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart? IFG does not plan to use efficiency credits.

Continuous Compliance Requirements

§63.7535 Is there a minimum amount of monitoring data I must obtain?
IFG will collect and maintain all 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). Noted.

(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. Noted.

(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. [Noted.](#)

(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. [Noted.](#)

§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. [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.

(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.

(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.

(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. 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, ... NA

(d) For startup and shutdown, you must meet the work practice standards according to items 5 and 6 of Table 3 of this subpart. IFG will meet the work practice standards as required.

§63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?
IFG does not intend to use the emissions averaging provisions.

Notification, Reports, and Records

§63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(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. The Laclede facility currently includes two boilers that are affected sources. IFG previously submitted the required notification for the existing boilers. IFG plans to submit a revised notification for the Wellons boiler.

(c) As specified in §63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source. IFG will re-submit the initial notification within 15 days after startup of the Wellons boiler.

(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. 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).

(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."

IFG will provide the 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).

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 ... **NA**

(g) If you intend to commence or recommence combustion of solid waste, ... **NA**

(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, ... **IFG has no reason to think a physical change or fuel switch would ever occur at the Wellons boiler.**

§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. 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. 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.**

(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. The details of the compliance report are listed in the regulation. IFG will follow the regulation.**

(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, SO₂, 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 of startup and shutdown, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section. The details of the compliance report are listed in the regulation. IFG will follow the regulation.

(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). Noted.

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section. The electronic reporting requirements are described in detail in the regulation. IFG will follow the regulation.

(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.

(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.

§63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section. IFG will keep all the required records.

(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).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section. IFG will keep all the required records.

(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. **Noted**

(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. IFG will keep all the required records.

(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.

(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. NA

(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. NA

(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 ...NA

(f) If you elect to use efficiency credits ...NA

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 ...NA

(h) If you operate a unit in the unit designed to burn gas ...NA

§63.7560 In what form and how long must I keep my records?

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

(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. **Noted.**

(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. **Noted.**

Other Requirements and Information

§63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you.

§63.7570 Who implements and enforces this subpart? Does not apply to IFG.

§63.7575 What definitions apply to this subpart? Key definitions are included in this FRA. Other definitions have been omitted 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: The heat input of the Wellons boiler is 1.15 TBtu/hr.

(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.

Table 1 to Subpart DDDDD of Part 63—Emission Limits for New or Reconstructed Boilers and Process Heaters
Does not apply. The Wellons is classified as an existing boiler.

Table 2 to Subpart DDDDD of Part 63—Emission Limits for Existing 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 . . .	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.

^aIf 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.

^bIncorporated by reference, see §63.14.

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 meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater	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. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management program and provide recommendations for improvements consistent with the definition of energy management program, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup	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, <u>clean dry biomass</u> , 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

If your unit is . . .	You must meet the following . . .
	<p>§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 ... OR</p> <p>(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).</p> <p>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.</p>
<p>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</p>	<p>You must operate all CMS during shutdown.</p> <p>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, ... 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.</p> <p>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.</p>

^aAs 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 . . .
<p>4. Electrostatic precipitator control on a boiler or process heater not using a PM CPMS</p>	<p>a. This option is for boilers and process heaters that operate dry control systems (<i>i.e.</i>, 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).</p>
<p>7. Performance testing</p>	<p>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.</p>
<p>8. Oxygen analyzer system</p>	<p>For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O₂ 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).</p>

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.
	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	Method 3A or 3B at 40 CFR part 60, appendix A-1 of this chapter, or ANSI/ASME PTC 19.10-1981. ^a

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

^aIncorporated by reference, see §63.14.

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 ASTM D6323 ^a (for 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, 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 (for solid samples), or EPA SW-846-7470A ^a (for liquid samples), or EPA 821-R-01-013 (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, 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 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, 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.

^aIncorporated 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 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.

^aOperating limits must be confirmed or reestablished during performance tests.

^bIf 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.

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

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	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 HCl, 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.

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)	

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)-	Compliance with Standards and	Yes.

Citation	Subject	Applies to subpart DDDDD
(b)(5), (b)(7), (c)	Maintenance Requirements	
§63.6(e)(1)(i)	General duty to minimize emissions.	No. See §63.7500(a)(3) for the general duty requirement.
§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)(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)(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)(ii)	Operation and maintenance of CMS	Yes.
§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)(iii)	Maintenance records	Yes.
§63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§63.10(d)(1) and (2)	General reporting requirements	Yes.
§63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§63.10(e)	Additional reporting requirements for sources with CMS	Yes.
§63.10(f)	Waiver of recordkeeping or reporting requirements	Yes.
§63.12	State Authority and Delegation	Yes.
§63.13-63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions	Yes.