Bath Iron Works Corporation
Sagadahoc County
Bath, Maine
A-333-77-4-A

Departmental
Findings of Fact and Order
New Source Review
NSR #4

FINDINGS OF FACT

After review of the air emission license application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 Maine Revised Statutes (M.R.S.) § 344 and § 590, the Maine Department of Environmental Protection (the Department) finds the following facts:

I. REGISTRATION

A. Introduction

FACILITY	Bath Iron Works Corporation
LICENSE TYPE	06-096 C.M.R. ch. 115, Minor Modification
NAICS CODES	336611
NATURE OF BUSINESS	Shipbuilding and Repair
FACILITY LOCATION	Bath, Maine

B. NSR License Description

Bath Iron Works Corporation (BIW) has requested a New Source Review (NSR) license for the installation of two 2.2 MMBtu/hr dual fuel-fired boilers in Building 71 as part of heating infrastructure upgrades. The upgrade will also include the installation of three wall-mounted gas-fired boilers, but these units are below the significance threshold requiring licensing.

C. Emission Equipment

The following new equipment is addressed in this NSR license:

Fuel Burning Equipment

Equipment	Maximum Capacity (MMBtu/hr)	Maximum Firing Rate	Fuel Type, % sulfur
Building 71 Boiler #1	2.2	2136 scf/hr	Natural Gas
		15.7	Distillate, 0.0015 %S
Building 71 Boiler #2	2.2	2136 scf/hr	Natural Gas
		15.7	Distillate, 0.0015 %S
*Building 77, Boiler #1	0.53	515 scf/hr	Natural Gas
*Building 74, Boiler #1	0.53	515 scf/hr	Natural Gas
*Building 74, Boiler #2	0.53	515 scf/hr	Natural Gas

* units are below the licensing threshold, listed for completeness purposes only

D. Definitions

Distillate Fuel means the following:

- Fuel oil that complies with the specifications for fuel oil numbers 1 or 2, as defined by the American Society for Testing and Materials (ASTM) in ASTM D396;
- Diesel fuel oil numbers 1 or 2, as defined in ASTM D975;
- Kerosene, as defined in ASTM D3699;
- Biodiesel, as defined in ASTM D6751; or
- Biodiesel blends, as defined in ASTM D7467.

E. Project Description

BIW is making facility upgrades to the AEGIS Complex by replacing the heating infrastructure which has become unreliable. Currently the complex is heated with steam supplied from the main boiler room in the main yard via underground piping. This piping has developed leaks and will no longer be utilized once the upgraded heating system has been installed and is operational. With these upgrades to the complex, each building will have its own independent heat source instead of being supplied through an underground steam piping system.

BIW plans to equip the central boiler room of Building 71 with two 2.2 MMBtu/hr boilers equipped to fire either natural gas or distillate fuel. The boilers are manufactured by Smith (Model 28 HE-5-6) and are equipped with a Power Flame dual-fuel burner. The flexibility to fire these two fuels will ensure that in the event of an interruption in delivery of one fuel, BIW will have access to another fuel eliminating the chance of losing heat to the facility and will allow BIW the flexibility of switching fuels for financial reasons.

Building 74 will be equipped with two wall-mounted, natural gas-fired condensing boilers, each with a heat input of 0.53 MMBtu/hr. Building 77 will be outfitted with one natural gas-fired wall-mounted boiler rated at 0.53 MMBtu/hr.

Installation and start-up of these units is scheduled for winter 2019/2020.

F. Application Classification

All rules, regulations, or statutes referenced in this air emission license refer to the amended version in effect as of the issued date of this license.

The application for BIW does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing, or recordkeeping requirements.

The modification of a major source is considered a major or minor modification based on whether or not expected emissions increases exceed the "Significant Emission Increase" levels as given in *Definitions Regulation*, 06-096 Code of Maine Rules (C.M.R.) ch. 100.

Emissions from Boilers #1 & #2 to be located in Building 71 were calculated based on the boilers operating 8,760 hours per year. The tabulated emissions are based on the worst-case emissions scenario, that is, resulting from the fuel producing the highest emissions. Since the boilers will be subject to a facility wide heat input restriction and the new boilers will displace the heat demand from the existing boilers, the addition of these boilers is not expected to increase total annual emissions.

Pollutant	Future Building 71 Boilers 1 & 2 License Allowed (ton/year)	Significant Emissions Increase Levels (ton/year)
PM	1.54	25
PM_{10}	1.54	15
$PM_{2.5}$	0.96	10
SO_2	0.09	40
NO_x	2.72	40
CO	1.58	100
VOC	0.09	40
CO_2e	<75,000	75,000

Note: The values in the previous table are for the new boilers to be located in Building 71. No other equipment is directly affected by this NSR license. The existing boilers will remain in place and will continue to heat and supply steam to other parts of the facility.

Since emissions increases do not exceed significant emissions increase levels, this NSR license is determined to be a minor modification under *Minor and Major Source Air Emission License Regulations,* 06-096 C.M.R. ch. 115. An application to incorporate the requirements of this NSR license into the Part 70 air emission license shall be submitted no later than 12 months from commencement of operations of the boilers.

II. BEST PRACTICAL TREATMENT (BPT)

A. Introduction

In order to receive a license, the applicant must control emissions from each unit to a level considered by the Department to represent Best Practical Treatment (BPT), as defined in *Definitions Regulation*, 06-096 C.M.R. ch. 100. Separate control requirement categories exist for new and existing equipment as well as for those sources located in designated non-attainment areas.

BPT for new sources and modifications requires a demonstration that emissions are receiving Best Available Control Technology (BACT), as defined in 06-096 C.M.R. ch. 100. BACT is a top-down approach to selecting air emission controls considering economic, environmental, and energy impacts.

B. Building 71 Boilers #1 and #2 (Boilers #1 and #2)

BIW plans to operate Boilers #1 and #2 for steam, heat, and hot water needs of Building 71. Boilers #1 and #2 are each rated at 2.2 MMBtu/hr and can fire natural gas and distillate fuel. The boilers were manufactured in 2019 are to be installed at the facility in winter 2019/2020. These boilers will exhaust through a combined stack.

1. BACT Findings

   a. Particulate Matter (PM and PM_{10})

      Particulate matter emissions from fuel combustion are formed from incomplete combustion of fuel and non-combustible material in the fuel. Emissions of particulate matter from new natural gas-fired boilers are generally very low. Given the size of the units and the minimal particulate matter emissions from the burning of natural gas, add-on emission control equipment for control of particulate matter from Boilers #1 and #2 when firing natural gas is not economically feasible.

Boilers #1 and #2 may also fire ultra-low sulfur fuel (15ppm). PM emissions from the firing of ultra-low sulfur distillate fuel are also generally low. Thus, given the size of the unit, add-on emission control equipment for control of particulate matter from Boiler #1 and #2 when firing distillate fuel is not economically feasible.

The Department finds firing natural gas or firing distillate fuel, use of efficient burner combustion technology, and emission limits of 0.05 lb/MMBtu and 0.11 lb/hr when firing natural gas and 0.08 lb/MMBtu and 0.18 lb/hr when firing distillate fuel to be BACT for PM and PM_{10} emissions from Boilers #1 and #2.

b. Sulfur Dioxide (SO_2)

Sulfur dioxide is formed from the combustion of sulfur present in the fuel. Potential control options for sulfur dioxide emissions include the use of fuel with a low sulfur content, sorbent injection, and SO_2 scrubbing technologies such as flue gas desulfurization and packed-bed scrubbers.

Emissions of sulfur dioxide from new natural gas-fired boilers are very low due to the low sulfur content of natural gas. Given the low level of sulfur dioxide emissions from the firing of natural gas, add-on emission control equipment for control of sulfur dioxide from Boilers #1 and #2 when firing natural gas is not economically feasible.

Due to the use of a low sulfur fuel such as ultra-low sulfur distillate fuel, the use of add-on emission control equipment for the control of SO_2 emissions from Boilers #1 and #2 when firing distillate fuel is not economically feasible. The use of this low-sulfur fuel results in similar SO_2 emissions as natural gas. The use of ultra-low sulfur distillate fuel, which has a sulfur content of less than 0.0015% by weight (15 ppm), is economically feasible.

The Department finds the use of natural gas or the use of distillate fuel with a maximum sulfur content not to exceed 0.0015% by weight (15 ppm) and an emission limit of 0.01 lb/hr when firing either natural gas or distillate fuel to be BACT for SO_2 emissions from Boilers #1 and #2.

c. Nitrogen Oxides (NO_x)

Nitrogen oxides mainly consist of nitric oxide (NO) and nitrogen dioxide (NO_2). NO_x from fuel combustion are generated through one of three mechanisms: fuel NO_x, thermal NO_x, and prompt NO_x. Fuel NO_x is produced by the oxidation of nitrogen in the fuel source, with low nitrogen content fuels such as distillate fuel and natural gas producing less NO_x than fuels with higher levels of fuel-bound nitrogen. Thermal NO_x forms in the high temperature area of the combustor and increases exponentially with increases in flame temperature and linearly with increases in residence time. Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame; this produces an insignificant amount of NO_x.

Control of NO_x emissions can be accomplished using one of three methods: the use of add-on controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR); the use of combustion control techniques, such as low NO_x burners, flue gas recirculation (FGR), and good combustion practices; and the combustion of clean fuel, such as natural gas and distillate fuel.

Given the size of the units and the low potential annual NO_x emissions from the units, the use of add-on controls such as SCR and SNCR are not economically feasible when firing either natural gas or distillate fuel.

Combustion control methods available to control NO_x from small industrial and commercial boilers include low NO_x burners, FGR, and good combustion practices. 'Low NO_x burners' refers to burner components (burner register, atomizing nozzle, and diffuser) that are designed to achieve lower NO_x by mixing the fuel and combustion air in a way that limits NO_x formation. This is generally done by mixing the combustion air and fuel in multiple stages and by utilizing a specially designed nozzle and/or diffuser to achieve a particular flame pattern. Although the use of low NO_x burners is technically feasible, it is economically infeasible for firing natural gas and distillate fuel in Boilers #1 and #2. In addition, this technology has not been found as BACT for units of similar size.

In FGR systems, a portion of the exiting combustion gases are recirculated back into the combustion zone. This process lowers peak flame temperatures, and therefore thermal NO_x formation, by allowing the relatively cool flue gas to absorb heat released by the burner flame. Although considered technically feasible, the use of FGR is not economically feasible for small boilers such as Boilers #1 and #2 due to the moderately high capital costs of the ductwork needed to span from the burner outlet to the combustion air duct, operating costs associated with the energy requirements of recirculation fans, and marginal emission reduction benefit. Additionally, FGR systems can affect heat transfer and system pressures.

Good combustion practices include operating the system based on the design and recommendations provided by the manufacturer and by maintaining proper air-to-fuel ratios with periodic maintenance checks.

The Department finds the use of natural gas or the use of distillate fuel, the use of good combustion practices, and emission limits of 0.21 lb/hr when firing natural gas and 0.31 lb/hr when firing distillate fuel to be BACT for NO_x emissions from Boilers #1 and #2.

d. Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

Emissions of carbon monoxide and volatile organic compounds are a result of incomplete combustion, caused by conditions such as insufficient residence time or limited oxygen availability. Potential control options for CO and VOC emissions include combustion controls and the use of a catalyst system.

Emissions of CO and VOC from new natural gas-fired boilers are generally low. Given the size of the unit and the low potential CO and VOC emissions, the use of add-on emission control equipment for the control of CO and VOC emissions from Boilers #1 and #2 when firing natural gas or distillate fuel are not considered economically feasible. Instead, BIW has proposed the use of efficient burner combustion technology.

The Department finds the use of natural gas or the use of distillate fuel, the use of efficient burner combustion technology, and the following emission limits to be BACT for CO and VOC emissions from Boilers #1 and #2:

Pollutant	Fuel	lb/hr
CO	Natural gas	0.18
	Distillate fuel	0.08
VOC	Natural gas	0.01
	Distillate fuel	0.01

e. Visible Emissions

Visible emissions from the combined stack shall not exceed 10% opacity on a six-minute block average basis when either or both Boilers #1 and #2 are in operation and firing natural gas.

Visible emissions from the combined stack shall not exceed 20% opacity on a six-minute block average basis when:
(1) either or both Boilers #1 and #2 are in operation and firing distillate
(2) at least one boiler is firing distillate

f. Heat Input Restriction

The heat input attributed to the firing of natural gas or distillate fuel in Building 71 Boilers #1 and #2 shall be accounted for in the facility-wide heat input limit of 392,200 MMBtu/year based on a 12-month rolling total.

2. Emission Limits

The BACT emission limits for Boilers #1 and #2 when firing natural gas were based on the following:

PM/PM_{10}	–	0.05 lb/MMBtu based on 06-096 C.M.R. ch. 115, BACT
SO_2	–	0.6 lb/MMscf based on AP-42, Table 1.4-2, dated 7/98
NO_x	–	100 lb/MMscf based on AP-42, Table 1.4-1, dated 7/98
CO	–	84 lb/MMscf based on AP-42, Table 1.4-1, dated 7/98
VOC	–	5.5 lb/MMscf based on AP-42, Table 1.4-2, dated 7/98
Visible Emissions	–	06-096 C.M.R. ch. 115, BACT

The BACT emission limits for Boiler #1 and #2 when firing distillate fuel were based on the following:

PM/PM_{10}	–	0.08 lb/MMBtu based on 06-096 C.M.R. ch. 115, BACT
SO_2	–	based on firing distillate fuel with a maximum sulfur content of 0.0015% by weight
NO_x	–	20 lb/1000 gal based on AP-42, Table 1.3-1, dated 5/10
CO	–	5 lb/1000 gal based on AP-42, Table 1.3-1, dated 5/10
VOC	–	0.34 lb/1000 gal based on AP-42, Table 1.3-3, dated 5/10
Visible Emissions	–	06-096 C.M.R. ch. 115, BACT

The BACT emission limits for Boilers #1 and #2 are the following:

Unit	PM (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boiler #1 Natural gas	0.11	0.11	0.01	0.21	0.18	0.01
Boiler #1 Distillate fuel	0.18	0.18	0.01	0.31	0.08	0.01
Boiler #2 Natural gas	0.11	0.11	0.01	0.21	0.18	0.01
Boiler #2 Distillate fuel	0.18	0.18	0.01	0.31	0.08	0.01

Visible emissions from the combined stack shall not exceed 10% opacity on a six-minute block average basis when either or both Boilers #1 and #2 are in operation and firing natural gas.

Visible emissions from the combined stack shall not exceed 20% opacity on a six-minute block average basis when:

a. either or both Boilers #1 and #2 are in operation and firing distillate
b. at least one boiler is firing distillate

The heat input attributed to the firing of natural gas or distillate fuel in Building 71 Boilers #1 and #2 shall be accounted for in the facility-wide heat input limit of 392,200 MMBtu/year based on a 12-month rolling total.

The distillate fuel fired in Boilers #1 and #2 shall not exceed a sulfur content of 0.0015% by weight (15 ppm). Compliance with this limit shall be demonstrated by fuel records from the supplier indicating the sulfur content of the fuel.

3. Periodic Monitoring

Periodic monitoring for Boilers #1 and #2 shall include recordkeeping to document fuel use both on a monthly and 12-month rolling total basis. Documentation shall include the type of fuel used and sulfur content of the fuel, if applicable. Natural gas is measured through the one meter into the building, so natural gas use for each boiler shall be estimated.

4. New Source Performance Standards (NSPS): 40 C.F.R. Part 60, Subpart Dc

Due to the size of each unit, Boilers #1 and #2 are not subject to *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units,* 40 C.F.R. Part 60, Subpart Dc for units greater than 10 MMBtu/hr manufactured after June 9, 1989. [40 C.F.R. § 60.40c]

5. NESHAP 40 C.F.R. Part 63, Subpart DDDDD

BIW is a major source of HAP emissions, and some of the emissions units at the facility are subject to the requirements of the federal regulation 40 C.F.R. Part 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*. This regulation establishes emissions limitations and work practice standards governing HAP emissions for each unit which falls into one of the subcategories listed under "What are the subcategories of Boilers & Process Heaters?" in 40 C.F.R. § 63.7499. This section addresses general requirements applicable to a source subject to Subpart DDDDD. This regulation applies to BIW's existing boilers as well as the new boilers to be installed. For the purposes of this subpart, Boilers #1 and #2 are dual-fuel units, have a heat input below 5 MMBtu/hr, and are considered to be in the "Units designed to burn liquid fuel" subcategory as defined in Subpart DDDDD.

a. Work Practice Standards [40 C.F.R. Part 63, Subpart DDDDD, Table 3]

(1) BIW shall conduct a tune-up of each boiler according to the procedures specified in § 63.7540(a)(10)(i) through (vi) no later than 61 months after the

initial start-up of the unit. Each 5 year tune up shall be conducted no more than 61 months after the previous tune-up. [40 C.F.R. § 63.7515(d)]

(2) Tune-ups for each boiler shall be conducted as specified to demonstrate continuous compliance. Delay of the burner inspection specified in 40 C.F.R. § 63.7540(a)(10)(i) until the next scheduled or unscheduled unit shutdown is permitted; however, an inspection of each burner shall occur at least once every 72 months. [40 C.F.R. § 63.7540(a)(12)]

(i) As applicable, inspect the burner and clean or replace any components of the burner as necessary (BIW may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). 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 (BIW may delay the inspection until the next scheduled unit shutdown);

(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 below:

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.

[40 C.F.R. § 63.7540 (a)(10)(vi)(A)-(C)]

(3) If the boiler is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup. [40 C.F.R. § 63.7540(a)(13)]

b. Notifications

(1) BIW shall submit an Initial Notification no later than 15 days after the actual date of start-up of Boilers #1 and #2. The initial notification shall be submitted to both the Department and to U.S. EPA Region I and in accordance with 40 C.F.R. § 63.9(b) and § 63.7545(c).

(2) Recordkeeping
The facility shall maintain records in accordance with 40 C.F.R. § 63.7555 that contain information necessary to document compliance with all applicable requirements, including but not limited to the following:
(i) A copy of each notification and report submitted to comply with this Subpart, along with any supporting documentation.
(ii) Records of tune-ups, as applicable.

The facility shall also maintain records in accordance with 40 C.F.R. § 63.10(b).

(3) Reporting
(i) BIW shall submit a compliance report for each tune-up required by this Subpart in accordance with 40 C.F.R. § 63.7550.
(ii) BIW shall submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI in accordance with 40 C.F.R. § 63.7550(h)(3).

C. Incorporation into the Part 70 Air Emission License

Per *Part 70 Air Emission License Regulations*, 06-096 C.M.R. ch. 140 § 1(C)(8), for a modification at the facility that has undergone NSR requirements or been processed through 06-096 C.M.R. ch. 115, the source must apply for an amendment to their Part 70 license within one year of commencing the proposed operations, as provided in 40 C.F.R. Part 70.5.

D. Annual Emissions

The proposed addition of Building 71 Boilers #1 and #2 will not change or increase the licensed total annual emissions from the facility.

III. AMBIENT AIR QUALITY ANALYSIS

BIW previously submitted an ambient air quality impact analysis outlined in air emission license A-333-77-3-A (June 13, 2014) demonstrating that emissions from the facility, in conjunction with all other sources, do not violate ambient air quality standards (AAQS). An additional ambient air quality impact analysis is not required for this NSR license.

ORDER

Based on the above Findings and subject to conditions listed below, the Department concludes that the emissions from this source:

- will receive Best Practical Treatment,
- will not violate applicable emission standards,
- will not violate applicable ambient air quality standards in conjunction with emissions from other sources.

The Department hereby grants New Source Review License A-333-77-4-A pursuant to the preconstruction licensing requirements of 06-096 C.M.R. ch. 115 and subject to the specific conditions below.

Severability. The invalidity or unenforceability of any provision of this License or part thereof shall not affect the remainder of the provision or any other provisions. This License shall be construed and enforced in all respects as if such invalid or unenforceable provision or part thereof had been omitted.

SPECIFIC CONDITIONS

(1) Natural Gas and Distillate Fuel

A. Fuel Use

1. Building 71 Boilers #1 and #2 are licensed to fire natural gas and distillate fuel. [06-096 C.M.R ch. 115, BACT]
2. The heat input attributed to the firing of natural gas or distillate fuel in Building 71 Boilers #1 and #2 shall be accounted for in the facility-wide heat input limit of 392,200 MMBtu/year based on a 12-month rolling total as listed in A-333-77-3-A (6/13/14) and A-333-70-L-R/A (3/21/17).
3. BIW shall fire distillate fuel with a maximum sulfur content limit of 0.0015% by weight (15 ppm). [06-096 C.M.R. ch. 115, BACT]
4. BIW shall maintain records on a monthly basis of the total distillate fuel consumed by Boilers #1 and #2 (each).
5. BIW shall maintain records on a monthly basis of the total natural gas fuel consumed by Boilers #1 and #2 (combined).

B. Building 71 Boilers #1 and #2 (Boilers #1 and #2)

1. Emission limits when firing natural gas [06-096 C.M.R. ch. 115, BACT]:

Unit	PM (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boiler #1	0.11	0.11	0.01	0.21	0.18	0.01
Boiler #2	0.11	0.11	0.01	0.21	0.18	0.01

2. Emission limits when firing distillate fuel [06-096 C.M.R. ch. 115, BACT]:

Unit	PM (lb/hr)	PM_{10} (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boiler #1	0.18	0.18	0.01	0.31	0.08	0.01
Boiler #2	0.18	0.18	0.01	0.31	0.08	0.01

3. Visible emissions

a. Visible emissions from the combined stack shall not exceed 10% opacity on a six-minute block average basis when either or both Boilers #1 and #2 are in operation and firing natural gas. [06-096 C.M.R. ch. 115, BACT]

b. Visible emissions from the combined stack shall not exceed 20% opacity on a six-minute block average basis when:
(1) either or both Boilers #1 and #2 are in operation and firing distillate
(2) at least one boiler is firing distillate
[06-096 C.M.R. ch. 115, BACT]

(2) **NESHAP 40 C.F.R. Part 63, Subpart DDDDD for Building 71 Boilers #1 and #2**

A. BIW shall comply with the requirements of 40 C.F.R. Part 63, Subpart DDDDD as applicable to Boilers #1 and #2. [40 C.F.R. § 63.7495(a)]

B. Work Practice Standards [40 C.F.R. Part 63, Subpart DDDDD, Table 3]

1. BIW shall conduct a tune-up of each boiler according to the procedures specified in § 63.7540(a)(10)(i) through (vi) no later than 61 months after the initial start-up of the unit. Each 5 year tune up shall be conducted no more that 61 months after the previous tune-up. [40 C.F.R. § 63.7515(d)]

2. Tune-ups for each boiler shall be conducted as specified to demonstrate continuous compliance. Delay of the burner inspection specified in 40 C.F.R. § 63.7540(a)(10)(i) until the next scheduled or unscheduled unit

shutdown is permitted; however, an inspection of each burner shall occur at least once every 72 months. [40 C.F.R. § 63.7540(a)(12)]

a. As applicable, inspect the burner and clean or replace any components of the burner as necessary (BIW may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown). 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;
b. 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;
c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (BIW may delay the inspection until the next scheduled unit shutdown).
d. 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;
e. 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
f. Maintain on-site and submit, if requested by the Administrator, a report containing the information below:
   (1) 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;
   (2) A description of any corrective actions taken as a part of the tune-up; and
   (3) 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.

[40 C.F.R. § 63.7540 (a)(10)(vi)(A)-(C)]

3. If the boiler is not operating on the required date for a tune-up, the tune-up shall be conducted within 30 calendar days of startup.
   [40 C.F.R. § 63.7540(a)(13)]

C. Notifications

1. BIW shall submit an Initial Notification no later than 15 days after the actual date of start-up of Boilers #1 and #2. The initial notification shall be submitted to both

the Department and to U.S. EPA Region I and in accordance with 40 C.F.R. § 63.9(b) and § 63.7545(c).

2. Recordkeeping

The facility shall maintain records in accordance with 40 C.F.R. § 63.7555 that contain information necessary to document compliance with all applicable requirements, including but not limited to the following:
(1) A copy of each notification and report submitted to comply with this Subpart, along with any supporting documentation.
(2) Records of tune-ups, as applicable.

The facility shall also maintain records in accordance with 40 C.F.R. § 63.10(b).

3. Reporting

a. BIW shall submit a compliance report for each tune-up required by this Subpart in accordance with 40 C.F.R. § 63.7550.

b. BIW shall submit all reports required by Table 9 of this subpart electronically to the EPA via the CEDRI in accordance with 40 C.F.R. § 63.7550(h)(3).

(3) BIW shall submit an application to incorporate this NSR license into the Part 70 air emission license no later than 12 months from commencement of the requested operation. [06-096 C.M.R. ch. 140, Section 1(C)(8)]

DONE AND DATED IN AUGUSTA, MAINE THIS 22nd DAY OF January , 2020.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: for
GERALD D. REID, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: 11/18/2019
Date of application acceptance: 11/18/2019

Date filed with the Board of Environmental Protection:

Filed
JAN 22 2020
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This Order prepared by Lisa P. Higgins, Bureau of Air Quality.