DEPARTMENT ORDER

Stratton Lumber, Inc.	**Departmental**
Franklin County	**Findings of Fact and Order**
Stratton, Maine	**New Source Review**
A-9-77-1-A	**NSR #1**

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	Stratton Lumber, Inc.
LICENSE TYPE	06-096 C.M.R. ch. 115, Minor Modification
NAICS CODES	321113
NATURE OF BUSINESS	Lumber Mill
FACILITY LOCATION	66 Fontaine Road, Stratton, Maine

B. NSR License Description

Stratton Lumber, Inc. (Stratton) has requested a New Source Review (NSR) license to install two new biomass-fired boilers.

C. Emission Equipment

The following new equipment is addressed in this NSR license:

Fuel Burning Equipment

Equipment	Maximum Capacity (MMBtu/hr)	Maximum Firing Rate (ton/hr)	Fuel Type	Stack #
Boiler #3	29.0	3.2*	Biomass	8
Boiler #4	29.0	3.2*	Biomass	8

* The maximum firing rate was based on a heat content of 4,500 BTU per pound of biomass at 50% moisture.

The following existing equipment is affected, but not modified, by this project:

Fuel Burning Equipment

Equipment	Maximum Capacity (MMBtu/hr)	Maximum Firing Rate (ton/hr)	Fuel Type	Stack #
Boiler #1	22.5	2.5*	Biomass	1

* The maximum firing rate was based on a heat content of 4,500 BTU per pound of biomass at 50% moisture.

D. Definitions

Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (*e.g.,* trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings). This definition also includes wood chips and processed pellets made from wood or other forest residues. Inclusion in this definition does not constitute a determination that the material is not considered a solid waste. Stratton should consult with the Department before adding any new biomass type to its fuel mix.

Records or *Logs* mean either hardcopy or electronic records.

Shutdown means the period in which cessation of operation of a boiler is initiated for any purpose. Shutdown begins when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, or when no fuel is being fed to the boiler, whichever is earlier. Shutdown ends when the boiler no longer supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, and no fuel is being combusted in the boiler.

Startup means:

1. Either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) 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 (such as steam or hot water) from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or
2. The period in which operation of a boiler is initiated for any purpose. Startup begins with either the first-ever firing of fuel in a boiler for the purpose of supplying useful thermal energy (such as steam or hot water) for heating, cooling or process purposes or producing electricity, or the firing of fuel in a boiler for any purpose after a shutdown event. Startup ends 4 hours after when the boiler supplies useful thermal energy (such as steam or hot water) for heating, cooling, or process purposes or generates electricity, whichever is earlier.

E. Project Description

Stratton intends to install two new biomass-fired boilers, Boiler #3 and Boiler #4, in order to increase plant-wide steam production capability. Stratton has an existing biomass-fired boiler (Boiler #1) and an existing propane-fired boiler (Boiler #2). The two new boilers will be identical units, each with a heat input capacity of 29.0 MMBtu/hr. The new boilers will burn wet biomass with an estimated moisture content of 50%, by weight. Stratton has proposed limiting the facility wide annual heat input for all three biomass-fired boilers combined (Boiler #1, Boiler #2, and Boiler #3) to 440,000 MMBtu per year. Stratton has also proposed lowering the existing license annual heat input limit for Boiler #1 from 177,390 MMBtu/yr to 130,000 MMBtu/yr.

The new boilers will be located in a new building adjacent to the sawmill building. Each proposed boiler will be equipped with its own multi-cyclone after which the exhaust gases will be combined and ducted to an electrostatic precipitator (ESP).

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 the new biomass-fired boilers 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. For a major stationary source, the expected emissions increase from each new, modified, or affected unit may be calculated as equal to the difference between the post-modification projected actual emissions and the baseline actual emissions for each NSR regulated pollutant.

1. Baseline Actual Emissions

   Baseline actual emissions (BAE) are equal to the average annual emissions from any consecutive 24-month period within the ten years prior to submittal of a complete license application. Stratton has proposed using 1/2020 – 12/2021 as the 24-month baseline period from which to determine baseline actual emissions for all pollutants for emission units affected as part of this project.

   BAE for existing modified and affected equipment are based on actual annual fuel use reported to the Department through *Emissions Statements*, 06-096 C.M.R. ch. 137 and licensed emission limits with the following exceptions:

a. Emissions of PM are not collected in the annual emissions report. PM emissions from all equipment were determined in a similar matter as the filterable portions of the PM_{10} emissions.

b. Emissions of PM_{10} and $PM_{2.5}$ in the annual emissions report are for the filterable portion only. Emissions of PM_{10} and $PM_{2.5}$ were adjusted to include emissions of condensable particulate matter (CPM).

BAE for new equipment are considered to be zero for all pollutants.

The results of this baseline analysis are presented in the table below.

Baseline Actual Emissions (1/2020 – 12/2021 Average)

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Boiler #1	21.08	21.08	21.08	1.41	15.46	70.28	7.03
Boilers #3 and #4	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	**14.05**	**14.05**	**14.05**	**1.40**	**15.45**	**42.00**	**1.20**

2. Projected Actual Emissions

Projected actual emissions (PAE) are the maximum actual annual emissions anticipated to occur in any one of the five years (12-month periods) following the date existing units resume regular operation after the project or any one 12-month period in the ten years following if the project involves increasing the unit’s design capacity or its potential to emit of a regulated pollutant.

New emission units must use potential to emit (PTE) emissions for projected actual emissions.

This project includes the installation of new biomass-fired boilers. Stratton has proposed a federally enforceable limit restricting the new biomass-fired boilers (Boilers #3 and #4) and the existing biomass-fired boiler (Boiler #1) to a combined heat input limit of 440,000 MMBtu/yr. In addition to the combined heat input limit for Boilers #1, #3, and #4, Stratton has proposed a reduction in the existing heat input limit for Boiler #1 from 177,390 MMBtu/yr to 130,000 MMBtu/yr. Stratton has elected to conservatively use PTE in place of PAE in calculating future emissions. Stratton has calculated PTE based on the worst-case operating scenario of Boilers #1, #3, and #4 for each pollutant as outlined in the following table.

Pollutant	PTE Calculated Based On…
$PM/PM_{10}/PM_{2.5}$	Boiler #1 operating at the license limit of 130,000 MMBtu/yr with the remainder of the combined heat input limit fired in Boilers #3 and #4
SO_2	Boilers #1, #3, and #4 firing a combined 440,000 MMBtu/yr
NO_x	Boilers #1, #3, and #4 firing a combined 440,000 MMBtu/yr
CO	Boiler #1 operating at the license limit of 130,000 MMBtu/yr with the remainder of the combined heat input limit fired in Boilers #3 and #4
VOC	Boilers #1, #3, and #4 firing a combined 440,000 MMBtu/yr

For Boiler #1, emissions were calculated based on the emission limits established in Air Emission License A-9-71-O-R (3/24/2015). Emissions of PM, PM_{10}, $PM_{2.5}$, NO_x, CO, and VOC from Boilers #3 and #4 were calculated based on EPA's Compilation of Air Pollutant Emission Factors, AP-42 ch. 1.6. SO_2 emissions from Boilers #3 and #4 were calculated using the same emission factor as for Boiler #1.

PTE emissions from the affected equipment are shown below.

Potential to Emit

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Boilers #1, #3, and #4*	30.35	30.35	30.35	5.18	48.40	158.00	9.14

* Combined emissions, based on worst case operating scenarios described above.

3. Emissions Increases

Emissions increases are calculated by subtracting BAE and excludable emissions from the PTE. The emission increase is then compared to the significant emissions increase levels.

Pollutant	Baseline Actual Emissions 01/20 – 12/21 (ton/year)	Potential to Emit (ton/year)	Emissions Increase (ton/year)	Significant Emissions Increase Levels (ton/year)
PM	21.08	30.35	9.27	25
PM_{10}	21.08	30.35	9.27	15
$PM_{2.5}$	21.08	30.35	9.27	10
SO_2	1.41	5.18	3.77	40
NO_x	15.46	48.40	32.94	40
CO	70.28	158.00	87.72	100
VOC	7.03	9.14	2.11	40

4. Classification

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 operation of either Boiler #3 or Boiler #4, whichever occurs first.

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. Boiler #3 and Boiler #4

Boilers #3 and #4 are identical units, each with a heat input capacity of 29.0 MMBtu/hr that burn biomass. Each boiler will be equipped with a multiclone after which the exhaust gases will be combined and ducted to an ESP before exhausting through a shared stack at 60 feet above ground level.

1. BACT Findings

   Following is a summary of the BACT analysis submitted by Stratton and the Department's determination of BACT for control of emissions from Boilers #3 and #4.

   a. Particulate Matter (PM, PM_{10}, $PM_{2.5}$)
   Particulate matter control devices applicable to biomass-fired boilers include cyclonic separators (multiclones), wet scrubbers, electrostatic precipitators (ESPs), and fabric filters. Typical control efficiencies are included in the following table.

Control Option	PM/PM_{10} Control Efficiency
Multicone with ESP or Fabric Filter	95-99%
Wet Scrubber	90-95%
Multiclone	60-75%

   Stratton has identified a multiclone followed by an ESP as the most effective available control strategy with an expected control efficiency for PM/PM_{10} of 95-99%. Because Stratton has proposed the most stringent control strategy as BACT, further analysis of identified control technologies is not required. Boilers #3 and #4 will each be equipped with a multiclone, after which the exhaust streams from the two boilers will be combined and routed to an ESP.

   The Department has determined BACT for $PM/PM_{10}/PM_{2.5}$ emissions from Boilers #3 and #4 is the use of a multiclone on each boiler, an ESP on the combined exhaust from the multiclones on the two boilers, and the emission limits listed in the tables below.

   b. Sulfur Dioxide (SO_2)
   Stratton has proposed to fire only biomass in Boilers #3 and #4. The use of these fuels results in minimal emissions of SO_2, and additional add-on pollution controls are not economically feasible.

   The Department has determined BACT for SO_2 emissions from Boilers #3 and #4 is the use of clean biomass and the emission limits listed in the tables below.

   c. Nitrogen Oxides (NO_x)
   NO_x is formed during the combustion of biomass in the boilers. "Thermal" NO_x emissions are formed when atmospheric nitrogen and oxygen present in the combustion air supply react with each other due to high combustion temperatures. "Fuel" NO_x emissions are formed when nitrogen present in the fuel is oxidized during combustion. The biomass fuel used by the proposed boilers will contain relatively small amounts of nitrogen (typically less than 0.2% expected).

NO_x control techniques are generally organized into two separate groups: combustion controls and post-combustion controls. Combustion controls affect the combustion conditions to minimize the formation of NO_x, while post-combustion controls remove NO_x after it has formed.

Newer solid fuel boilers are typically equipped with a combustion air distribution system that provides a portion of the required combustion air at the fuel bed location, with additional combustion air provided in the upper portion of the furnace. These systems are carefully designed to control fuel/air mixing, excess air levels, and other combustion parameters to achieve efficient combustion and low emissions.

Post combustion technologies include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR).

SCR uses a catalyst to convert NO_x to nitrogen gas. An ammonia-based reagent is injected into the boiler's combustion gases upstream of the catalyst, and the reactions to remove NO_x occur in the presence of the catalyst. The optimum temperature range for SCR technology is typically 600 to 750 °F. Thus, most SCR installations have incorporated the catalyst into the heat recovery section of the boiler to meet the required temperature window. This poses a problem for solid fuel boilers where particulate matter concentrations in the heat recovery section of the boiler (i.e., upstream from the PM control device) can be sufficiently high to potentially blind and plug the catalyst. For this reason, SCR systems have generally not been applied to biomass-fired boiler systems.

SNCR involves the injection of an ammonia-based reagent directly into the furnace section of the boiler within a temperature window of 1,600 to 2,100 °F. Under these conditions, the reagent will react with and reduce NO_x emissions without the need for a catalyst.

EPA's RBLC[1] does not contain any entries for a biomass boiler with input capacity less than 100 MMBtu/hour and permitted since January 1, 2012, which required post-combustion NO_x controls, nor were any identified in a search of permits recently issued in New England states. With proper combustion controls, NO_x emissions from biomass boilers of this or similar size can be limited to relatively low annual levels.

The Department has determined BACT for NO_x emissions from Boilers #3 and #4 is the use of combustion controls inherent to newer boiler design including systems

[1] The U.S. EPA's RACT/BACT/LAER Clearinghouse (RBLC) is a database of control technology determinations derived from New Source Review requirements including Reasonably Available Control Technology (RACT), Best Available Control Technology (BACT), and/or Lowest Achievable Emission Rate (LAER).

designed to control fuel/air mixing, excess air levels, and other combustion parameters to achieve efficient combustion and low emissions, and the emission limits listed in the tables below.

d. <u>Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)</u>
CO and VOC are formed as a result of incomplete combustion of organic material in the furnace. Stratton considered several control strategies for the control of CO and VOC including oxidation catalysts, thermal oxidizers, and use of combustion controls.

Oxidation catalysts and thermal oxidizers both have high capital, maintenance, and operational costs considering the size of the boilers in question and the level of emissions. The constituents of wood-fired boiler exhaust can potentially cause plugging and fouling of the catalyst material, reducing their effectiveness and increasing maintenance requirements. A review of EPA's RBLC did not indicate oxidation catalysts and thermal oxidizers as typical control strategies for boilers of this type and size.

CO and VOC emissions can be controlled by maintaining proper combustion conditions within the boilers. This involves control of excess air levels, distribution of combustion air within the furnace, and achieving proper gas turbulence and residence time.

The Department has determined BACT for CO and VOC emissions from Boilers #3 and #4 is the use of good combustion controls and the emission limits listed in the tables below.

e. <u>Emission Limits</u>
The BACT emission limits for Boilers #3 and #4 were based on the following:

$PM/PM_{10}/PM_{2.5}$	–	0.07 lb/MMBtu based on 06-096 C.M.R. ch. 115, BACT and 40 C.F.R. § 63.11201(a) and Table 1, #4]
SO_2	–	0.025 lb/MMBtu based on AP-42 Table 1.6-2 (dated 4/2022)
NO_x	–	0.22 lb/MMBtu based on AP-42 Table 1.6-2 (dated 4/2022)
CO	–	0.60 lb/MMBtu based on AP-42 Table 1.6-2 (dated 4/2022)
VOC	–	0.017 lb/MMBtu based on AP-42 Table 1.6-3 (dated 4/2022)
Visible Emissions	–	06-096 C.M.R. ch. 115, BACT

The BACT emission limits for Boiler #3 and Boiler #4 are the following:

Unit	Pollutant	lb/MMBtu
Boiler #3	PM	0.07
Boiler #4	PM	0.07

Unit	PM (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boiler #3 biomass	2.03	2.03	2.03	0.73	6.38	17.40	0.49
Boiler #4 biomass	2.03	2.03	2.03	0.73	6.38	17.40	0.49

2. Visible Emissions

   Visible emissions from the shared stack of Boilers #3 and #4 shall not exceed 30% opacity on a six-minute block average basis. [06-096 C.M.R. ch. 115, BACT]

3. Controls

   Boiler #3 and Boiler #4 shall each be equipped with a multiclone. Additionally, the boilers shall be equipped with a shared ESP. Combustion control systems that may include the control of fuel/air mixing, excess air levels, and other combustion parameters shall be utilized to achieve efficient combustion and minimize emissions. These controls shall be operated whenever the associated boilers are in operation.

4. Periodic Monitoring

   Periodic monitoring for the boilers shall include recordkeeping to document fuel use both on a monthly and 12-month rolling total basis.

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

   Due to the size and year of manufacture, Boilers #3 and #4 are 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]

   Stratton shall comply with all requirements of 40 C.F.R. Part 60, Subpart Dc applicable to Boiler #3 and Boiler #4 including, but not limited to, the following:

a. Notifications

Stratton shall submit notification to EPA and the Department of the date of construction, anticipated start-up, and actual start-up. This notification shall include the design heat input capacity of the boiler and the type of fuel to be combusted. [40 C.F.R. § 60.48c(a)]

b. Reporting and Recordkeeping

Stratton shall maintain records of the amounts of each fuel combusted during each calendar month. [40 C.F.R. § 60.48c(g)]

6. National Emission Standards for Hazardous Air Pollutants (NESHAP): 40 C.F.R. Part 63, Subpart JJJJJJ

Boilers #3 and #4 are subject to the *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources*, 40 C.F.R. Part 63, Subpart JJJJJJ. These units are considered new biomass boilers. [40 C.F.R. §§ 63.11193 and 63.11195]

A summary of the currently applicable federal 40 C.F.R. Part 63, Subpart JJJJJJ requirements is listed below. Notification forms and additional rule information can be found on the following website: https://www.epa.gov/stationary-sources-air-pollution/compliance-industrial-commercial-and-institutional-area-source.

a. Emission Limits

(1) Except during periods of startup and shutdown, emissions from Boilers #3 and #4 shall not exceed the following limit [40 C.F.R. § 63.11201(a)]:

Unit	Pollutant	lb/MMBtu
Boiler #3	PM	0.07
Boiler #4	PM	0.07

(2) Except during periods of startup and shutdown, Stratton shall maintain the 30-day rolling average total secondary electric power of the ESP at or above the minimum total secondary electric power as defined in 40 C.F.R. § 63.11237. [40 C.F.R. Part 63, Subpart JJJJJJ, Table 3]

b. Testing Requirements

Stratton shall conduct PM performance (stack) tests according to 40 C.F.R. § 63.11212 on a triennial basis, except as specified below. Triennial performance tests must be completed no more than 37 months after the previous performance test.

If, when demonstrating initial compliance with the PM emission limits, the performance test results show that the PM emissions are equal to or less than half of the PM emission limit, Stratton may choose to conduct performance tests for PM every fifth year but must continue to comply with all applicable operating limits and monitoring requirements, and must comply with the following:

(1) Each performance test must be conducted no more than 61 months after the previous performance test.

(2) If performance test results show PM emissions greater than half of the PM emission limit, Stratton must conduct subsequent performance tests on a triennial basis.

A Notification of Intent to conduct a performance stack test must be submitted at least 60 days before the performance stack test is scheduled to begin.

[40 C.F.R. §§ 63.11220(a), 63.11220(c), and 63.11225(a)(2)]

c. Establishing Operating Limits

Stratton shall establish a site-specific minimum total secondary electric power operating limit for the ESP according to 40 C.F.R. § 63.11211(b) using data from the secondary electric power monitors and the PM performance stack tests.
[40 C.F.R. Part 63, Subpart JJJJJJ, Table 6 and § 63.11211]

d. Compliance Dates, Notifications, and Work Practice Requirements

(1) Initial Notification of Compliance

An Initial Notification submittal to EPA is due within 120 days after the source becomes subject to the standard. [40 C.F.R. § 63.11225(a)(2)]

(2) Stratton shall demonstrate initial compliance with each applicable emission limit specified in Table 1 of 40 C.F.R. Part 63, Subpart JJJJJJ by conducting performance (stack) tests according to 40 C.F.R. Part 63 § 63.11212 and Table 4. Initial compliance must be demonstrated no later than 180 days after startup of Boilers #3 and #4. [40 C.F.R. §§ 63.11210(a) and (d)]

(3) Stratton shall collect the total secondary electric power monitoring system data for the ESP according to 40 C.F.R. §§ 63.11224 and 63.11221. The data shall be reduced to 30-day rolling averages. Stratton shall maintain the 30-day rolling

average total secondary electric power at or above the minimum total secondary electric power according to 40 C.F.R. § 63.11211.
[40 C.F.R. Part 63, Subpart JJJJJ Table 7 and § 63.11222]

(4) Startup and Shutdown

Stratton shall minimize startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, Stratton must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. [40 C.F.R. Part 63, Subpart JJJJJ, § 63.11201 and Table 2]

(5) Boiler Tune-Up Program

(i) A boiler tune-up program shall be implemented. [40 C.F.R. § 63.11223]

(ii) Each tune-up shall be conducted at a frequency specified by the rule and based on the size, age, and operations of the boiler. See chart below:

Boiler Category	**Tune-Up Frequency**
New or Existing Oil, Biomass and Coal fired boilers that are not designated as "Boilers with Less Frequent Tune-up Requirements" listed below	Every 2 years

[40 C.F.R. § 63.11223(a) and Table 2]

(iii) The boiler tune-up program, conducted to demonstrate continuous compliance, shall be performed as specified below:

1. <u>As applicable</u>, inspect the burner, and clean or replace any component of the burner as necessary. Delay of the burner inspection until the next scheduled shutdown is permitted, not to exceed 36 months from the previous inspection. [40 C.F.R. § 63.11223(b)(1)]
2. Inspect the flame pattern, <u>as applicable</u>, and adjust the burner as necessary to optimize the flame pattern, consistent with the manufacturer's specifications. [40 C.F.R. § 63.11223(b)(2)]
3. Inspect the system controlling the air-to-fuel ratio, <u>as applicable</u>, and ensure it is correctly calibrated and functioning properly. Delay of the inspection until the next scheduled shutdown is permitted, not to exceed 36 months from the previous inspection. [40 C.F.R. § 63.11223(b)(3)]
4. Optimize total emissions of CO, consistent with manufacturer's specifications. [40 C.F.R. § 63.11223(b)(4)]

5. Measure the concentration in the effluent stream of CO in parts per million by volume (ppmv), and oxygen in volume percent, **before** and **after** 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. [40 C.F.R. § 63.11223(b)(5)]
6. If a unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of start-up.
[40 C.F.R. § 63.11223(b)(7)]

(iv) Tune-Up Report: A tune-up report shall be maintained onsite and, submitted to the Department and/or EPA upon request. The report shall contain the following information:

1. The concentration of CO in the effluent stream (ppmv) and oxygen (volume percent) measured at high fire or typical operating load both **before** and **after** the boiler tune-up;
2. A description of any corrective actions taken as part of the tune-up of the boiler; and
3. The types and amounts of fuels used over the 12 months prior to the tune-up of the boiler, 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 use by each unit. [40 C.F.R. § 63.11223(b)(6)]

(6) Notification of Compliance Status

After conducting the initial stack test, a Notification of Compliance Status shall be submitted to EPA no later than 60 days after completing the test.
[40 C.F.R. § 63.1125(a)(4)]

(7) Compliance Report

A compliance report shall be prepared by March 1st of each year. The report shall be maintained by the source and submitted to the Department and/or to the EPA upon request, unless the source experiences any deviations from the applicable requirements of this Subpart during the previous calendar year, then the report must be submitted to the Department and to the EPA by March 15th. The report must include the items contained in § 63.11225(b)(1) through (4), including the following: [40 C.F.R. § 63.11225(b)]
(i) Company name and address;
(ii) A statement of whether the source has complied with all the relevant requirements of this Subpart;

(iii) A statement certifying truth, accuracy, and completeness of the notification and signed by a responsible official and containing the official's name, title, phone number, email address, and signature;

(iv) The following certifications, as applicable:

1. "This facility complies with the requirements in 40 C.F.R. § 63.11223 to conduct tune-ups of each boiler in accordance with the frequency specified in this Subpart."
2. "No secondary materials that are solid waste were combusted in any affected unit."
3. "This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

(v) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken; and

(vi) The total fuel use by each affected boiler subject to an emission limit for each calendar month within the reporting period.

c. Recordkeeping

Records shall be maintained consistent with the requirements of 40 C.F.R. Part 63, Subpart JJJJJ including the following [40 C.F.R. § 63.11225(c)]:

(1) Copies of notifications and reports with supporting compliance documentation;
(2) Identification of each boiler, the date of tune-up, procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned;
(3) Records of the occurrence and duration of each malfunction of each applicable boiler; and
(4) Records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore the malfunctioning boiler.

Records shall be in a form suitable and readily available for expeditious review. EPA requires submission of Notification of Compliance Status reports through their electronic reporting system. [40 C.F.R. § 63.11225(a)(4)(vi)]

C. Incorporation Into the Part 70 Air Emission License

Pursuant to *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 table below provides an estimate of facility-wide annual emissions for the purposes of calculating the facility's annual air license fee and establishing the facility's potential to emit (PTE). Only licensed equipment is included, i.e., emissions from insignificant activities are excluded. Similarly, unquantifiable fugitive particulate matter emissions are not included except when required by state or federal regulations. Maximum potential emissions were calculated based on the following assumptions:

- A combined annual heat input limit of 440,000 MMBtu/yr for Boilers #1, #3, and #4 with no more than 130,000 MMBtu/yr from Boiler #1;
- Operating Boiler #2 for 8,760 hr/yr;
- A total maximum throughput of 150 MMBF/yr for the kilns, with 75 MMBF/yr of the total being fir species; and
- Operating the Emergency Generator for 100 hr/yr.

This information does not represent a comprehensive list of license restrictions or permissions. That information is provided in the Order section of this license.

Total Licensed Annual Emissions for the Facility
Tons/year
(used to calculate the annual license fee)

	PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	CO	VOC
Boilers #1, #3, and #4	30.4	30.4	30.4	5.2	48.4	158.0	9.1
Boiler #2	0.4	0.4	0.4	0.1	3.0	11.1	0.7
Kilns	--	--	--	--	--	--	71.6
Emergency Generator	--	--	--	--	--	--	--
Total TPY	**30.8**	**30.8**	**30.8**	**5.3**	**51.4**	**169.1**	**81.4**

Pollutant	Tons/year
Single HAP	9.9
Total HAP	24.9

III. AMBIENT AIR QUALITY ANALYSIS

A. Overview

A refined modeling analysis was performed to show that emissions from Stratton will not cause or contribute to violations of National Ambient Air Quality Standards (NAAQS) for SO_2, PM_{10}, $PM_{2.5}$, NO_2, or CO or to Class II increments for SO_2, PM_{10}, $PM_{2.5}$, or NO_2.

Since Stratton is a major source for only CO, it has been determined by Maine Department of Environmental Protection, Bureau of Air Quality (MEDEP-BAQ) that an assessment of Class I Air Quality Related Values (AQRVs) is not required.

B. Model Inputs

The AERMOD refined dispersion model was used to address NAAQS and increment impacts.

All modeling was performed in accordance with all applicable requirements of the MEDEP-BAQ and the United States Environmental Protection Agency (USEPA).

A valid, five-year, hourly, off-site, meteorological database was used in the AERMOD refined modeling analysis. Automated Surface Observing System (ASOS) wind data was collected at height of 10 meters at the Berlin, New Hampshire National Weather Service (NWS) meteorological monitoring site during the period of 2017 - 2021. The following parameters and their associated heights were as follows:

TABLE III-1 : Meteorological Parameters and Collection Heights

Parameter	Sensor Height(s)
Scalar Wind Speed	10 meters
Scalar Wind Direction	10 meters
Temperature	2 meters

The Berlin ASOS station was selected as the primary meteorological surface data site due to:

- its proximity to Stratton;
- surface data is meteorologically representative of application site;
- very similar topographically and elevation-wise;
- instrumentation and exposure of the meteorological monitoring site; and
- completeness of data set which meets all minimum data recovery requirements.

All missing data were interpolated or coded as missing, per USEPA guidance.

Surface meteorological data was combined with concurrent hourly cloud cover and upper-air data obtained from the Caribou National Weather Service (NWS). Missing cloud cover and/or upper-air data values were interpolated or coded as missing, per USEPA guidance.

All necessary, representative, micrometeorological surface variables for inclusion into AERMET (surface roughness, Bowen ratio, and albedo) were calculated using the AERSURFACE utility program and from procedures recommended by USEPA.

Point-source parameters used in the modeling are listed in Table III-2.

TABLE III-2 : Point Source Stack Parameters

Stack	Stack Base Elevation (m)	Stack Height (m)	GEP Stack Height (m)	Stack Diameter (m)	UTM Easting NAD83 (m)	UTM Northing NAD83 (m)
CURRENT/PROPOSED						
Stratton						
• Boiler #1	354.65	18.29	28.93	0.61	387,597	4,999,844
• Boiler #2	354.84	15.24	28.17	0.41	387,650	4,999,883
• Boilers #3 and #4	354.08	15.24	28.17	1.17	387,679	4,999,902
ReEnergy						
• ReEnergy	353.57	88.40	-	2.74	387,764	4,999,553
2010 BASELINE ($PM_{2.5}$ INCREMENT)						
Stratton						
• Boiler #1	354.65	18.29	28.93	0.61	387,597	4,999,844
1987 BASELINE (NO_2 INCREMENT)						
Stratton						
• No Stratton sources existed in the 1987 baseline year; no baseline credit to be taken.						
1977 BASELINE (SO_2/PM_{10} INCREMENT)						
Stratton						
• No Stratton sources existed in the 1977 baseline year; no baseline credit to be taken.						

Emission parameters for NAAQS and Class II increment modeling are listed in Table III-3. Emission parameters are based on the maximum license allowed operating configuration.

For the purpose of determining maximum predicted impacts, the following assumptions were used:

- NO_x emissions were assumed to convert to NO_2 using USEPA's Tier II Ambient Ratio Method (ARM2) minimum and maximum ratios of 0.5 and 0.9, respectively; and
- all particulate emissions were conservatively assumed to convert to PM_{10} and $PM_{2.5}$.

TABLE III-3 : Stack Emission Parameters

Stack	Averaging Periods	SO_2 (g/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)	NO_x (g/s)	CO (g/s)	Stack Temp (K)	Stack Velocity (m/s)
MAXIMUM LICENSE ALLOWED								
Stratton								
• Boiler #1	All	0.056	0.851	0.851	0.624	2.835	477.59	15.25
• Boiler #2	All	0.001	0.011	0.011	0.085	0.318	477.59	20.92
• Boilers #3 and #4	All	0.183	0.511	0.511	1.607	4.382	477.59	12.98
ReEnergy								
• Main Stack	All	-	1.331	1.331	4.302	-	463.71	26.43
2010 BASELINE ($PM_{2.5}$ INCREMENT)								
• Stratton conservatively assumed no credit for any existing sources (Boiler #1 Only) in the 2010 baseline year.								
1987 BASELINE (NO_2 INCREMENT)								
• No Stratton sources existed in the 1987 baseline year; no baseline credit to be taken.								
1977 BASELINE (SO_2/PM_{10} INCREMENT)								
• No Stratton sources existed in the 1977 baseline year; no baseline credit to be taken.								

C. Single Source Modeling Impacts

The AERMOD model results for Stratton alone are shown in Table III-4. Maximum predicted impacts that exceed their respective significance level are indicated in boldface type. For comparison to the Class II significance levels, the impacts for all pollutants/averaging periods were conservatively based on the maximum High-1st-High predicted values. No additional refined modeling was required for pollutants that did not exceed their respective significance levels.

TABLE III-4 : Maximum AERMOD Impacts from Stratton Alone

Pollutant	Averaging Period	Max Impact (μg/m^3)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Class II Significance Level (μg/m^3)
SO_2	1-hour	**13.97**	388,490	4,999,780	413.22	7.9
	3-hour	9.72	388,440	4,999,130	413.55	25
PM_{10}	24-hour	**11.50**	387,780	4,999,980	352.01	5
$PM_{2.5}$	24-hour	**11.50**	387,780	4,999,980	352.01	1.2
	Annual	**0.56**	387,890	4,999,830	353.85	0.2
NO_2	1-hour	**120.96**	388,490	4,999,780	413.22	7.5
	Annual	**1.60**	387,890	4,999,830	353.85	1
CO	1-hour	418.96	388,490	4,999,780	413.22	2,000
	8-hour	147.60	387,800	5,000,000	352.79	500

D. Secondary Formation of $PM_{2.5}$

Since Stratton's proposed NO_x emissions for this modification are greater than 40 TPY, a review of secondary impacts due to $PM_{2.5}$ precursor emissions (secondary $PM_{2.5}$) is required.

A $PM_{2.5}$ compliance demonstration must account for both primary $PM_{2.5}$ from a source's direct PM emissions as well as secondarily formed $PM_{2.5}$ from a source's precursor emissions of NO_x and SO_2. The formation of secondary $PM_{2.5}$ is dependent on the concentrations of precursor and relative species, atmospheric conditions, and the interactions of precursors with other entities, such as particles, rain, fog, or cloud droplets.

Since the contribution from secondary formation of $PM_{2.5}$ cannot be explicitly accounted for in AERMOD, the impact~~s~~ of secondarily formed $PM_{2.5}$ from Stratton was determined using a Tier I analysis following methodologies prescribed in USEPA's *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program (April 2019).*

For a Tier I secondary formation assessment, a source uses technically credible empirical relationships between precursor emissions and secondary impacts, based upon USEPA modeling. Specifically, USEPA has performed single-source photochemical modeling to examine the range of modeled estimated impacts of secondary $PM_{2.5}$ formation for different theoretical source types (based on pollutant, stack height, and location) for facilities in different geographical locations in the United States.

Stratton estimated the potential impact of its precursor emissions using Equation 2 from USEPA's MERPs guidance, in which a source's impacts is estimated as the product of the relevant hypothetical source air quality impacts relative to emissions, scaled either upwards or downwards to the emission rate of the project itself. Equation 2 is presented below:

$$\textit{Project Impact} = \begin{matrix}\textit{Project}\\ \textit{Emission Rate}\end{matrix} \; X \; \frac{\textit{Modeled impact from hypothetical modeling}}{\textit{Modeled emission rate from hypothetical modeling}}$$

This procedure was followed for both NO_x and SO_2 precursors and the individual contributions summed to achieve a final estimated potential secondary $PM_{2.5}$ concentration, as shown in Table III-5.

TABLE III-5 : Secondary $PM_{2.5}$ from NO_x & SO_2 Precursors

Pollutant	Potential Increase of Precursors (TPY)	Impact/Emissions Ratio ($\mu g/m^3$ / TPY)	Estimated Secondary $PM_{2.5}$ Impacts ($\mu g/m^3$)
NO_x	51.4	0.130208	0.0134
SO_2	4.4	0.963076	0.0085
Total Estimated Secondary $PM_{2.5}$ from NO_x and SO_2 precursors			**0.0219**

Using this methodology, the total estimated secondary $PM_{2.5}$ impact due to Stratton's NO_x and SO_2 precursor emissions were predicted to be extremely low (~0.02 µg/m^3) and are not expected to contribute significantly to the $PM_{2.5}$ NAAQS and Class I or Class II increment impacts.

E. Combined Source Modeling Impacts

As indicated in boldface type in Table III-4, other sources not explicitly included in the modeling analysis must be accounted for by using representative background concentrations for the area.

Background concentrations, listed in Table III-6, are derived from representative rural background data for use in the Central Maine region.

TABLE III-6 : Background Concentrations

Pollutant	Averaging Period	Background Concentration (µg/m^3)	Site Name, Location
SO_2	1-hour	5	Mic Mac Site, Presque Isle
	3-hour	4	
PM_{10}	24-hour	46	CKP Site, Lewiston
$PM_{2.5}$	24-hour	12	DEP Site, Presque Isle
	Annual	4	
NO_2	1-hour	40	Mic Mac Site, Presque Isle
	Annual	4	
CO	1-hour	1,102	Mic Mac Site, Presque Isle
	8-hour	789	

MEDEP examined other nearby sources to determine if any impacts would be significant in or near the Stratton's significant impact area. Due to the location of Stratton, extent of the predicted significant impact area and other nearby source's emissions, MEDEP has determined that only one additional source would be explicitly included in the combined-source refined modeling: ReEnergy.

The maximum combined-source AERMOD modeled impacts, which were explicitly normalized to the form of their respective NAAQS, were added with conservative rural background concentrations to demonstrate compliance with NAAQS, as shown in Table III-7.

As calculated in Section D, the total estimated secondarily formed $PM_{2.5}$ due to Stratton's NO_x and SO_2 precursor emissions (~0.02 µg/m^3) was added to the maximum modeled impact to achieve a final value.

Because all pollutant/averaging period impacts using this method meet NAAQS, no further NAAQS modeling analyses need to be performed.

TABLE III-7 : Maximum Combined Source Impacts (µg/m³)

Pollutant	Averaging Period	Max Impact (µg/m³)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Back-Ground (µg/m³)	Total Impact (µg/m³)	NAAQS (µg/m³)
SO_2	1-hour	18.35	388,490	5,000,030	415.96	5	23.35	196
	3-hour	9.72*	388,440	4,999,130	413.55	4	13.72	1,300
PM_{10}	24-hour	25.84	387,593	4,999,762	354.09	46	71.84	150
$PM_{2.5}$	24-hour	10.61	387,660	4,999,700	353.64	12	22.61	35
	Annual	2.04	387,660	4,999,700	353.64	4	6.04	12
NO_2	1-hour	140.26	387,820	4,999,850	352.72	40	180.26	188
	Annual	12.87	387,820	4,999,950	352.72	4	16.87	100
CO	1-hour	418.96*	388,490	4,999,780	413.22	1102	1520.96	40,000
	8-hour	147.60*	387,800	5,000,000	352.79	789	936.6	10,000

* = Value taken from Table III - 4, based on the maximum High-1st-High predicted impact.

F. Class II Increment

The AERMOD model was used to predict maximum Class II increment impacts.

Stratton did not exist during the 1987 or 1977 baseline years, so their SO_2, PM_{10}, and NO_x emissions are considered to be entirely increment consuming. In addition, Stratton conservatively assumed no credit would be taken for any sources that existed during the 2010 baseline year (Boiler #1 only).

Results of the Class II increment analysis are shown in Table III-8. All modeled maximum increment impacts were below all increment standards. Because all predicted increment impacts meet increment standards, no additional Class II SO_2, PM_{10}, $PM_{2.5}$, and NO_2 increment modeling needed to be performed.

As calculated in Section D, the total estimated secondarily formed $PM_{2.5}$ due to Stratton's NO_x and SO_2 precursor emissions (~0.02 µg/m³) was added to the maximum modeled $PM_{2.5}$ increment impact to achieve a final value.

TABLE III-8: Class II Increment Consumption

Pollutant	Averaging Period	Max Impact (µg/m³)	Receptor UTM E (m)	Receptor UTM N (m)	Receptor Elevation (m)	Class II Increment (µg/m³)
SO_2	3-hour	9.26	388,440	4,999,180	411.37	512
	24-Hour	2.08	388,440	4,999,030	414.38	91
	Annual	0.25	388,390	4,999,880	409.91	20
PM_{10}	24-Hour	7.83	388,340	4,998,980	396.76	30
	Annual	1.02	387,810	4,999,750	352.95	17
$PM_{2.5}$	24-Hour	7.83	388,340	4,998,980	396.76	9
	Annual	1.02	387,810	4,999,750	352.95	4
NO_2	Annual	1.39	388,390	4,999,580	400.61	25

G. Summary

In summary, it has been demonstrated that Stratton, in conjunction with other sources, will not cause or contribute to violations of NAAQS for SO_2, PM_{10}, $PM_{2.5}$, NO_2, or CO or to Class II increments for SO_2, PM_{10}, $PM_{2.5}$, or NO_2.

This determination is based on information provided by the applicant regarding the expected construction and operation of the proposed emission units. If the Department determines that any parameter (e.g., stack size, configuration, flow rate, emission rates, nearby structures, etc.) deviates from what was included in the application, the Department may require Stratton to submit additional information and may require an ambient air quality impact analysis at that time.

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-9-77-1-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) **Fuel**

A. Total combined fuel use for Boiler #1, Boiler #3, and Boiler #4 shall not exceed 440,000 MMBtu/yr of biomass on a 12-month rolling total basis. Total fuel use for Boiler #1 shall not exceed 130,000 MMBtu/yr on a 12-month rolling total basis. [06-096 C.M.R. ch. 115]

B. Compliance shall be demonstrated by fuel records showing the quantity, type, percent moisture, and heat content of fuel used in Boiler #1, Boiler #3, and Boiler #4. Records of fuel use shall be kept on a monthly and 12-month rolling total basis. Records demonstrating compliance with the annual heat input limitations shall be kept on a 12-month rolling total basis. [06-096 C.M.R. ch. 115]

(2) **Boiler #3 and Boiler #4**

A. Boiler #3 and Boiler #4 are licensed to fire biomass. [06-096 C.M.R. ch. 115, BACT]

B. Emissions shall not exceed the following except during periods of startup and shutdown:

Emission Unit	Pollutant	lb/MMBtu	Origin and Authority
Boiler #3	PM	0.07	06-096 C.M.R. ch. 115, BACT and 40 C.F.R. § 63.11201(a)
Boiler #4	PM	0.07	06-096 C.M.R. ch. 115, BACT and 40 C.F.R. § 63.11201(a)

C. Emissions shall not exceed the following [06-096 C.M.R. ch. 115, BACT]:

Unit	PM (lb/hr)	PM_{10} (lb/hr)	$PM_{2.5}$ (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	CO (lb/hr)	VOC (lb/hr)
Boiler #3	2.03	2.03	2.03	0.73	6.38	17.40	0.49
Boiler #4	2.03	2.03	2.03	0.73	6.38	17.40	0.49

D. Visible emissions from the shared stack of Boilers #3 and #4 shall not exceed 30% opacity on a six-minute block average basis. [06-096 C.M.R. ch. 115, BACT]

E. Combustion control systems of Boilers #3 and #4 shall be operated at all times to achieve efficient combustion and minimize emissions. This may include controlling fuel/air mixing, excess air levels, and other combustion parameters. [06-096 C.M.R. ch. 115, BACT]

F. Boiler #3 and Boiler #4 shall each be equipped with a multiclone. Additionally, the boilers shall be equipped with a shared ESP. These controls shall be operated whenever the associated boilers are in operation. [06-096 C.M.R. ch. 115, BACT]

G. Stratton shall comply with all requirements of 40 C.F.R. Part 60, Subpart Dc applicable to Boilers #3 and #4 including, but not limited to, the following:

1. Notification

   Stratton shall submit notification to EPA and the Department of the date of construction, anticipated start-up, and actual start-up. This notification shall include the design heat input capacity of the boilers and the type of fuel to be combusted. [40 C.F.R. § 60.48c(a)]

2. Reporting and Recordkeeping

   Stratton shall maintain records of the amounts of fuel combusted during each calendar month. [40 C.F.R. § 60.48c(g)]

H. Stratton shall comply with all requirements of 40 C.F.R. Part 63, Subpart JJJJJJ applicable to Boilers #3 and #4 including, but not limited to, the following: [incorporated under 06-096 C.M.R. ch. 115, BACT]

1. Emission Limits

   a. Except during periods of startup and shutdown, emissions from Boilers #3 and #4 shall not exceed the following limit [40 C.F.R. § 63.11201(a)]:

Unit	Pollutant	lb/MMBtu
Boiler #3	PM	0.07
Boiler #4	PM	0.07

   b. Except during periods of startup and shutdown, Stratton shall maintain the 30-day rolling average total secondary electric power of the ESP at or above the minimum total secondary electric power as defined in 40 C.F.R. § 63.11237. [40 C.F.R. Part 63, Subpart JJJJJJ, Table 3]

2. Testing Requirements

   Stratton shall conduct PM performance (stack) tests according to 40 C.F.R. § 63.11212 at representative operating load conditions for each unit and on a triennial basis, except as specified below. Triennial performance tests must be completed no more than 37 months after the previous performance test.

If, when demonstrating initial compliance with the PM emission limits, the performance test results show that the PM emissions are equal to or less than half of the PM emission limit, Stratton may choose to conduct performance tests for PM every fifth year but must continue to comply with all applicable operating limits and monitoring requirements, and must comply with the following:

a. Each performance test must be conducted no more than 61 months after the previous performance test.

b. If performance test results show PM emissions greater than half of the PM emission limit, Stratton must conduct subsequent performance tests on a triennial basis.

A Notification of Intent to conduct a performance stack test must be submitted at least 60 days before the performance stack test is scheduled to begin.

[40 C.F.R. §§ 63.11220(a), 63.11220(c), and 63.11225(a)(2)]

3. Stratton shall establish a site-specific minimum total secondary electric power operating limit for the ESP according to 40 C.F.R. § 63.11211(b) using data from the secondary electric power monitors and the PM performance stack tests.
[40 C.F.R. Part 63, Subpart JJJJJJ, Table 6 and § 63.11211]

4. An Initial Notification submittal to EPA is due within 120 days after the source becomes subject to the standard. [40 C.F.R. § 63.11225(a)(2)]

5. Stratton shall demonstrate initial compliance with each applicable emission limit specified in Table 1 of 40 C.F.R. Part 63, Subpart JJJJJJ by conducting performance (stack) tests according to 40 C.F.R. Part 63 § 63.11212 and Table 4. Initial compliance must be demonstrated no later than 180 days after startup of Boilers #3 and #4. [40 C.F.R. §§ 63.11210(a) and (d)]

6. Stratton shall collect the total secondary electric power monitoring system data for the ESP according to 40 C.F.R. §§ 63.11224 and 63.11221. The data shall be reduced to 30-day rolling averages. Stratton shall maintain the 30-day rolling average total secondary electric power at or above the minimum total secondary electric power according to 40 C.F.R. § 63.11211.
[40 C.F.R. Part 63, Subpart JJJJJJ Table 7 and § 63.11222]

7. Stratton shall minimize startup and shutdown periods and conduct startups and shutdowns according to the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, Stratton must follow recommended procedures for a unit of similar design for which manufacturer's

recommended procedures are available. [40 C.F.R. Part 63, Subpart JJJJJJ, § 63.11201 and Table 2]

8. The facility shall implement a boiler tune-up program. [40 C.F.R. § 63.11223]

   a. Each tune-up shall be conducted at a frequency specified by the rule and based on the size, age, and operations of the boiler. See chart below:

Boiler Category	**Tune-Up Frequency**
New or Existing Oil, Biomass and Coal fired boilers that are not designated as "Boilers with less frequent tune up requirements" listed below	Every 2 years

   [40 C.F.R. § 63.11223(a) and Table 2]

   b. The boiler tune-up program, conducted to demonstrate continuous compliance, shall be performed as specified below:

      (1) As applicable, inspect the burner, and clean or replace any component of the burner as necessary. Delay of the burner inspection until the next scheduled shutdown is permitted, not to exceed 36 months from the previous inspection. [40 C.F.R. § 63.11223(b)(1)]
      (2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern, consistent with the manufacturer's specifications. [40 C.F..R § 63.11223(b)(2)]
      (3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure it is correctly calibrated and functioning properly. Delay of the inspection until the next scheduled shutdown is permitted, not to exceed 36 months from the previous inspection. [40 C.F.R. § 63.11223(b)(3)]
      (4) Optimize total emissions of CO, consistent with manufacturer's specifications. [40 C.F.R. § 63.11223(b)(4)]
      (5) Measure the concentration in the effluent stream of CO in parts per million by volume (ppmv), and oxygen in volume percent, **before** and **after** 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. [40 C.F.R. § 63.11223(b)(5)]
      (6) If a unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 days of start-up. [40 C.F.R. § 63.11223(b)(7)]

   c. Tune-Up Report: A tune-up report shall be maintained onsite and submitted to the Department and EPA upon request. The report shall contain the following information:

(1) The concentration of CO in the effluent stream (ppmv) and oxygen (volume percent) measured at high fire or typical operating load both **before** and **after** the boiler tune-up;
(2) A description of any corrective actions taken as part of the tune-up of the boiler; and
(3) The types and amounts of fuels used over the 12 months prior to the tune-up of the boiler, 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 use by each unit. [40 C.F.R. § 63.11223(b)(6)]

9. Notification of Compliance Status

After conducting the initial stack test, a Notification of Compliance Status shall be submitted to EPA no later than 60 days after completing the test.
[40 C.F.R. § 63.1125(a)(4)]

10. Compliance Report

A compliance report shall be prepared by March 1st of each year. The report shall be maintained by the source and submitted to the Department and/or to the EPA upon request, unless the source experiences any deviations from the applicable requirements of this Subpart during the previous calendar year, then the report must be submitted to the Department and to the EPA by March 15th. The report must include the items contained in § 63.11225(b)(1) – (4), including the following: [40 C.F.R. § 63.11225(b)]

a. Company name and address;
b. A statement of whether the source has complied with all the relevant requirements of this Subpart;
c. A statement certifying truth, accuracy, and completeness of the notification and signed by a responsible official and containing the official's name, title, phone number, email address, and signature;
d. The following certifications, as applicable:
   (1) "This facility complies with the requirements in 40 C.F.R. § 63.11223 to conduct tune-ups of each boiler in accordance with the frequency specified in this Subpart."
   (2) "No secondary materials that are solid waste were combusted in any affected unit."
   (3) "This facility complies with the requirement in §§ 63.11214(d) and 63.11223(g) to minimize the boiler's time spent during startup and shutdown and to conduct startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available."

e. If the sources experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken; and
f. The total fuel use by each affected boiler subject to an emission limit for each calendar month within the reporting period.

11. Records shall be maintained consistent with the requirements of 40 C.F.R. Part 63, Subpart JJJJJJ including the following [40 C.F.R. § 63.11225(c)]:

a. Copies of notifications and reports with supporting compliance documentation;
b. Identification of each boiler, the date of tune-up, procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned;
c. Records of the occurrence and duration of each malfunction of each applicable boiler; and
d. Records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore the malfunctioning boiler.

Records shall be in a form suitable and readily available for expeditious review.

EPA requires submission of Notification of Compliance Status reports for tune-ups and energy assessments through their electronic reporting system. [40 C.F.R. § 63.11225(a)(4)(vi)]

(3) If the Department determines that any parameter value pertaining to construction and operation of the proposed emissions units, including but not limited to stack size, configuration, flow rate, emission rates, nearby structures, etc., deviates from what was submitted in the application or ambient air quality impact analysis for this air emission license, Stratton may be required to submit additional information. Upon written request from the Department, Stratton shall provide information necessary to demonstrate AAQS will not be exceeded, potentially including submission of an ambient air quality impact analysis or an application to amend this air emission license to resolve any deficiencies and ensure compliance with AAQS. Submission of this information is due within 60 days of the Department's written request unless otherwise stated in the Department's letter. [06-096 C.M.R. ch. 115, § 2(O)]

(4) Stratton shall submit an application to incorporate this NSR license into the facility's Part 70 air emission license no later than 12 months from commencement of the operation of either Boiler #3 or Boiler #4, whichever occurs first. [06-096 C.M.R. ch. 140 § 1(C)(8)]

DONE AND DATED IN AUGUSTA, MAINE THIS 11th DAY OF MAY, 2023.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY:________________________________ for

MELANIE LOYZIM, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: November 16, 2022
Date of application acceptance: November 28, 2022

Date filed with the Board of Environmental Protection:

This Order prepared by Benjamin Goundie, Bureau of Air Quality.

FILED

MAY 11, 2023

State of Maine
Board of Environmental Protection