STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION
17 STATE HOUSE STATION AUGUSTA, MAINE 04333-0017

DEPARTMENT ORDER

ND Paper Inc.
Oxford County
Rumford, Maine
A-214-77-21-A

Departmental
Findings of Fact and Order
New Source Review
NSR # 21

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	ND Paper Inc. (NDP)
LICENSE TYPE	06-096 C.M.R. ch. 115, Minor Modification
NAICS CODES	322110, 322121
NATURE OF BUSINESS	Pulp & Paper Mill
FACILITY LOCATION	35 Hartford Street, Rumford, Maine

B. NSR License Description

NDP is proposing to make physical modifications to the Recovery Boiler C, Cogen Boiler #6, and Cogen Boiler #7 to incorporate the capability to combust natural gas in each unit.

C. Emission Equipment

The following equipment is addressed in this NSR license:

Fuel Burning Equipment

Equipment	Maximum Capacity (MMBtu/hr)	Fuel Type	Stack #
Recovery Boiler C	759 (fuel oil)	fuel oil, spec. waste oil, natural gas, black liquor, soap	CREC
Cogen Boiler #6	610 (annual) 630 (24-hr)	fuel oil, natural gas, biomass, coal, TDF, DPC, CDD, CTW, specification and off-spec. waste oil, lime kiln rejects, LVHCs, HVLCs, SOGs, OCC residuals	6&7
Cogen Boiler #7	610 (annual) 630 (24-hr)		

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.

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

E. Project Description

NDP is proposing to make physical modifications to Recovery Boiler C, Cogen Boiler #6, and Cogen Boiler #7 to incorporate the capability to combust natural gas in each unit and offset the firing of fuel oil. Although the three units have natural gas listed as a licensed fuel in the facility's Part 70 license, the equipment and infrastructure required to fire this fuel was not installed. As the 18-month time period to begin construction has been exceeded since the issuance of the facility's permit which initially addressed the equipment and infrastructure required to fire natural gas, this license will serve to re-evaluate the requirements associated with firing natural gas and re-authorize an 18-month timeframe to begin construction as allowed in 06-096 C.M.R. ch. 115(3)(E)(5)(c).

The addition of natural gas to Recovery Boiler C, Cogen Boiler #6, and Cogen Boiler #7 is not expected to result in the increased production from the facility, but rather as adding operational flexibility to these units. There are no other units that would be considered "affected units" as a result of this project.

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 NDP 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. NDP has proposed using 01/2017 – 12/2018 as the 24-month baseline period from which to determine baseline actual emissions for all pollutants for emission units modified as part of this project.

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

   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).

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

Baseline Actual Emissions (01/2017 – 12/2018 Average)

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Recovery Boiler C	83.90	124.31	110.88	89.62	496.17	455.58	16.19
Cogen Boiler #6	7.52	30.27	29.45	429.33	590.42	17.85	0.81
Cogen Boiler #7	6.21	25.00	24.33	355.37	486.96	14.47	0.69
Total	97.63	179.58	164.66	874.32	1573.55	487.90	17.69

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.

a. Cogen Boilers #6 and #7

Cogen Boilers #6 and #7 are considered physically modified units as well as having the potential for the project to result in increased usage of this equipment due to the increased steam demand to support the natural gas pressure step-down process. PAE is based on the equivalent heat input of natural gas being fired, offsetting the firing of fuel oil in the baseline period.

For Cogen Boilers #6 and #7, emissions of PM, PM_{10}, $PM_{2.5}$, and SO_2 are based on AP-42, Table 1.4-2. Emissions of CO are based on AP-42, Table 1.4-1.

Emissions of NO_x are based on a proposed license limit, and emissions of VOC are based on the existing Part 70 license limit for the units.

b. Recovery Boiler C

Recovery Boiler C is considered a physically modified unit. PAE are based on the equivalent heat input of natural gas being fired, offsetting the firing of fuel oil in the baseline period.

For Recovery Boiler C, emissions of NO_x and CO were based on AP-42, Table 1.4-1, utilizing low NO_x burners.

Emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, and VOC based on AP-42, Table 1.4-2.

Projected actual emissions from the modified equipment are shown below.

Projected Actual Emissions

Equipment	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	VOC (tpy)
Recovery Boiler C	83.56	124.00	110.59	84.38	495.00	458.53	16.41
Cogen Boilers (Combined)	13.76	55.54	54.04	783.87	1082.18	32.81	1.51
Total	97.32	179.54	164.63	868.25	1577.18	491.34	17.92

3. Emissions Increases

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

Pollutant	Baseline Actual Emissions 01/2017 – 12/2018 (ton/year)	Projected Actual Emissions (ton/year)	Emissions Increase (ton/year)	Significant Emissions Increase Levels (ton/year)
PM	97.63	97.32	-0.31	25
PM_{10}	179.58	179.54	-0.04	15
$PM_{2.5}$	164.66	164.63	-0.03	10
SO_2	874.32	868.25	-6.07	40
NO_x	1573.55	1577.18	3.63	40
CO	487.9	491.34	3.44	100
VOC	17.69	17.92	0.23	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.

This NSR license is not licensing a new major stationary source of an NSR pollutant that is not greenhouse gases (GHG) nor is it authorizing a major modification for an NSR pollutant to an existing major stationary source. Therefore, greenhouse gases are not considered subject to regulation in this license pursuant to 40 C.F.R. §§ 51.166(b)(48)(iii - iv).

An application to incorporate the terms and conditions of this NSR license into the Part 70 air emission license shall be submitted no later than 12 months from the initial firing of natural gas in Recovery Boiler C, or Cogen Boilers #6 or #7 to additionally fire natural gas.

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. Recovery Boiler C

1. Equipment Description

Recovery Boiler C is a Babcock and Wilcox low odor design boiler used by NDP to recover pulping chemicals and produce steam. The unit has the capacity to fire 4.4 million pounds (MMlb) of dry black liquor solids per day or 759 MMBtu/hour of fuel oil. Emissions exit through a 290-foot above ground level (AGL) stack.

Recovery Boiler C's primary fuel is black liquor, the liquid containing dissolved wood residue and pulping chemicals from the digesters after pulping of wood chips. In Recovery Boiler C, inorganic chemicals in the black liquor are recovered in molten form, and organic constituents of the black liquor are combusted, supplying heat for steam generation.

NDP fires fuel oil, specification waste oil, and black liquor soap as auxiliary fuels. Typically, fuel oil is used only during startups, shutdowns, and to stabilize boiler operation. With this modification, NDP will replace six out of the total 10 fuel oil burners to fire exclusively natural gas. Each natural gas burner will have a rated capacity of 75 MMBtu/hr totaling 450 MMBtu/hr. Four of the existing burners will remain as fuel oil burners to maintain operational flexibility.

2. BACT and BPT Findings

NDP submitted a BACT analysis for control of emissions of CO and VOC from Recovery Boiler C while firing natural gas. The conversion of six burners from fuel oil to natural gas on Recovery Boiler C results in the net reduction of PM, PM_{10}, $PM_{2.5}$, SO_2, and NO_x emissions; therefore, this modification must meet the standard of best practical treatment (BPT) as opposed to best available control technology (BACT) for the above listed pollutants, pursuant to 06-096 C.M.R. ch. 115, § 4(A)(4)(d).

a. Particulate Matter (PM, PM_{10}, $PM_{2.5}$)

Particulate matter emissions from recovery boilers are primarily sodium salts caused by the carryover of solids and sublimation and condensation of inorganic chemicals from black liquor. Natural gas is an inherently clean fuel with low ash content and will have a negligible effect on the overall PM emissions from the unit. Recovery Boiler C is currently equipped with an ESP designed to control PM emissions.

Possible PM control technologies include use of mechanical collectors, wet scrubbers, ESPs, and baghouses/fabric filters. Baghouses and fabric filters are not compatible with the high moisture exhaust from recovery boilers. Mechanical collectors, such as multiclones, are not effective in controlling the types of PM emitted from recovery boilers. Wet scrubbers are technically feasible but less effective than ESPs.

The Department finds that maintaining the existing PM emission limits specified in the facility's Part 70 license and the continued use of an ESP represents BPT for particulate matter emissions.

b. Sulfur Dioxide (SO_2)

SO_2 is formed from the oxidation of sulfur contained in fuel. While black liquor combustion is the primary source of SO_2 in recovery boiler operations, this analysis focuses specifically on emissions from natural gas. Natural gas is an inherently low sulfur content fuel resulting in very low SO_2 emissions without additional controls. Potential control strategies for sulfur dioxide emissions include flue gas desulfurization (FGD), acid gas scrubbers, the use of alternative fuels, and good combustion practices. Installation of add-on SO_2 controls (e.g., FGD or acid gas scrubber) are potentially technically feasible but not economically justified given the negligible SO_2 emission rate from natural gas combustion. Natural gas has the lowest sulfur content out of the feasible auxiliary fuel options. Therefore, the Department finds that maintaining the existing SO_2 emission limits listed below and the use of natural gas as an auxiliary fuel represents BPT for SO_2 emissions.

c. Nitrogen Oxides (NO_x)

The control strategies considered by NDP included Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), water/steam injection, flue gas recirculation (FGR), low-NO_x burners, and use of proper maintenance, tuning, and combustion air design.

SCR systems utilize a catalyst bed and an ammonia-based reagent to convert NO_x into N_2, CO_2, and water. Due to the high PM concentrations in Recovery Boiler C's exhaust, it is not technically feasible to locate a SCR system ahead of PM control due to catalyst poisoning by soluble alkali metals in the gas stream. For SCR installation after the ESP, the gas stream from the ESP would be too cool for effective SCR operation and would require significant reheating of the exhaust stream to raise it to the optimal SCR temperature range. This supplemental fuel combustion would negate the environmental benefit of the SCR.

SNCR also utilizes an ammonia-based reagent but does not utilize a catalyst. Instead, the reagent is injected directly into the boiler in a location within the specific temperature range required for the NO_x reduction reaction to occur. In recovery boilers, the temperature window needed for effective SNCR is difficult to locate and maintain due to fluctuating load and liquor quality. In addition, the injection of a reagent into the recovery boiler risks chemical side reactions with sulfur compounds, potentially forming corrosive byproducts. These compounds can foul boiler surfaces and interfere with the recovery chemistry, degrading boiler performance and efficiency. There are no known applications demonstrating effective use of SNCR systems on recovery boilers.

FGR is not a viable option for pulp and paper recovery boilers because it would add additional gas volume in the furnace, increasing velocities and potentially causing more liquor carryover, which would result in increased fouling of the recovery furnace tubes (NCASI 2006). Ultra-low-NO_x burner designs typically require larger air delivery systems, which can limit the size of the burner that fits within the existing footprint of Recover Boiler C's burner openings and port configuration. An ultra-low-NO_x burner would be too small to deliver the necessary heat input into the boiler and is therefore not feasible.

Water/steam injection would not be relevant to kraft recovery furnaces since any injection of water into the furnace would quench the temperature and disrupt the necessary reducing conditions in the lower furnace, affecting chemical recovery efficiency. The introduction of any water could also potentially cause dangerous smelt-water explosions.

The use of low-NO_x burners along with proper maintenance, tuning, and combustion air design will effectively minimize NO_x emissions from natural gas combustion in Recovery Boiler C. The Department finds that maintaining the existing NO_x emission limits listed below in conjunction with these efforts represents BPT for NO_x emissions.

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

NDP considered several control strategies for the control of CO and VOC including oxidation catalysts, thermal oxidizers, and good combustion practices.

Oxidation catalysts and thermal oxidizers were both determined to not be technically feasible. Both control technologies would need to be installed after the existing electrostatic precipitator, which would then require significant input of thermal energy to bring the flue gas to the required temperature to allow for thermal destruction of pollutants.

CO emissions can be minimized effectively by maintaining optimum air-to-fuel ratios and by proper combustion design to ensure proper residence time and mixing. Oxygen monitoring in the exhaust stream allows for the feedback adjustment of combustion air, ensuring an optimum air-to-fuel ratio without sacrificing efficiency. In addition, staged combustion ensures complete combustion in Recovery Boiler C. These are all technically feasible CO control approaches.

The Department finds that maintaining the current CO and VOC emission limits in conjunction with good combustion practices represents BACT for CO and VOC emissions. Specifically, NDP proposes that its current limit of 222.0 lb/hr represents BACT for control of CO emissions and its current limit of 3.7 lb/hr represents BACT for control of VOC emissions for periods while firing natural gas.

e. Emission Limits

The BACT and BPT emission rates used to determine the potential actual emissions increase for Recovery Boiler C were based on the following:

Natural Gas

PM	–	7.6 lb/MMscf based on AP-42 Table 1.4-2 dated 7/98
$PM_{10}/PM_{2.5}$	–	7.6 lb/MMscf based on AP-42 Table 1.4-2 dated 7/98
SO_2	–	0.6 lb/MMscf based on AP-42 Table 1.4-2 dated 7/98
NO_x	–	140 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

As natural gas is fired as a supplemental fuel in Recovery Boiler C, its addition will not change any short-term emission limit specified in the facility's Part 70 license. This modification will also not change the visible emission standards applicable to Recovery Boiler C specified in the facility's Part 70 license.

C. Cogen Boilers #6 and #7

1. Equipment Description

Cogen Boilers #6 and #7 are identical, circulating fluidized bed (CFB) boilers manufactured by Pyropower. Each of the Cogen Boilers is presently equipped with Coen Model 4 oil burners. These boilers commenced construction in 1986 and started operation in 1990. Each has a rated capacity of 610 MMBtu/hour (annual) and 630 MMBtu/hour (24-hour period). Emissions from the two boilers exit through a common stack (Stack #6/7) and share common COMS and CEMS for SO_2, NO_x, O_2, CO_2, and opacity. The stack has an inside diameter of 11.5 feet and a height of 411 feet AGL.

Cogen Boilers #6 and #7 are licensed to fire a variety of fuels, including coal, natural gas, HVLCs, LVHCs, SOGs, biomass (including wood waste, creosote-treated wood (CTW), wastewater treatment plant sludge, construction & demolition debris (CDD), and waste papers), tire derived fuel (TDF), delayed petroleum coke (DPC), lime kiln rejects, oil (including specification waste oil, off-specification waste oil, and fuel oil with a sulfur content not to exceed 2.5% by weight), and old corrugated cardboard and double-lined kraft (collectively referred to as OCC) residuals. The firing rate capacity of Cogen Boilers #6 and #7 depends on what fuel or fuel mixture is employed.

This modification will replace the existing oil burners in Cogen Boilers #6 and #7 with natural gas burners, but will not preclude the future firing of fuel oil.

2. BACT and BPT Findings

NDP submitted a BACT analysis for control of emissions of PM, PM_{10}, $PM_{2.5}$, CO, and VOC from Cogen Boilers #6 and #7 while firing natural gas. The conversion of the fuel oil burners to natural gas burners on Cogen Boilers #6 and #7 results in the net reduction of SO_2 and NO_x emissions; therefore, this modification must meet the standard of BPT as opposed to BACT for those two pollutants, pursuant to 06-096 C.M.R. ch. 115, § 4(A)(4)(d).

a. Particulate Matter (PM, PM_{10}, $PM_{2.5}$)

Particulate matter (PM) emissions from Circulating Fluidized Bed (CFB) boilers are generated from the combustion of fuel. Natural gas is an inherently clean fuel with low ash content and will have a short-term reduction in PM emissions from the units. Both Cogen Boilers are currently equipped with a combination of mechanical collector multicyclones and an ESP which allows the boilers to meet a particulate matter emissions limit of 0.0074 lb/MMBtu. The only methodology for further reducing PM emissions from the Cogen Boilers is through add-on pollution control. Potential pollution control options include baghouses, dry electrostatic precipitators (ESP), wet ESP, multi-cyclones, biofiltration, and wet scrubber systems.

Dry electrostatic precipitators (dry ESP) control PM emissions using the force of an induced electrostatic charge. The particulate particles in the exhaust stream are negatively charged using high voltage electrodes and then drawn onto a positively charged collection surface. At periodic intervals, the collection surfaces (plates) are cleaned by electromagnetic "rappers" that deliver a blow to the surface header creating a vertical shock wave that causes the collected particulate to dislodge and fall into the hopper below. Dry ESPs are a technically feasible control technology and are currently installed on the Cogen Boilers #6 and #7.

Similar to a dry ESP, a wet ESP removes fine particulate matter including aerosols using ionization and an electric field where particles in the exhaust stream are negatively charged and then adhere onto a positively charged collection surface. However, rather than mechanical impulses or vibrations to dislodge particles from the plates, in wet ESPs the collector plates are cleaned with water. This happens by combination of condensation from the process gas and periodic flush cycles from a matrix of overhead nozzles. Wet ESPs produce blow-down water waste that requires disposal. There is also caustic and defoamer addition required for the process water. Wet ESPs are technically feasible control technology.

Biofiltration uses a biological process to capture and mitigate particulate matter emissions in which exhaust streams are directed through a filter bed containing microorganisms, such as bacteria and fungi, which act as active agents in capturing, degrading, and/or metabolizing the particulate matter. The biological process transforms the pollutants into largely harmless byproducts. The major advantage of biofiltration as a particulate matter emissions control device is its sustainability and environmental friendliness. Unlike the conventional methods described above, biofiltration does not rely on chemical agents or produce secondary pollutants, making it a greener alternative. The effectiveness of biofiltration depends on various factors, including the choice of microorganisms, the composition of the filter bed, and the specific characteristics of the particulate matter being targeted. Continuous research and development in this field aim to optimize biofiltration systems for enhanced performance and broader applicability in controlling particulate matter emissions. Currently, biofiltration has not been proven as an effective pollution control device for these types of combustion devices; therefore, it will not be evaluated further.

Cyclones and multi-cyclones are relatively simple devices which leverage centripetal force to separate particles from gas streams. The incoming exhaust gas gains high velocity upon entering the cyclone at the top inner wall. Gravity then guides the spinning gas downward, and the tapered design of the cyclone body sustains the cyclonic effect until particles drop out through the bottom into a hopper. Constructed typically from sheet metal, cyclones boast low capital costs, minimal operating expenses, and no moving parts. Multicyclones, consisting of smaller diameter units operating in parallel or series, adhere to the same operational principles as single cyclones but aim for high-efficiency PM collection. Cyclones are a technically feasible control technology and are currently installed on Cogen Boilers #6 and #7.

The effectiveness for wet ESPs, dry ESPs, and wet scrubbers are all theoretically able to achieve 99% control efficiency. However, both wet ESPs and wet scrubbers generate a wastewater stream that requires treatment and eventual disposal, therefore they have an incrementally negative environmental impact as compared to dry ESPs. The use of a multi-cyclone system followed by a dry ESP, as currently installed on the Cogen Boilers, has been demonstrated to be even more effective than any of the add-on control technologies alone. Furthermore, given the small

PM_{10} and $PM_{2.5}$ annual emissions increase due to this project (~0.3 TPY), the installation of additional pollution control measures would not be economically feasible.

The Department finds that maintaining the existing PM emission limits specified in the facility's Part 70 license and the continued use of multi-cyclones in conjunction with dry ESPs represents BACT for PM emissions from Cogen Boilers #6 and #7.

b. Sulfur Dioxide (SO_2)

Sulfur dioxide (SO_2) is formed from the oxidation of sulfur contained in fuel. Natural gas is an inherently low sulfur content fuel resulting in very low SO_2 emissions without the need for additional controls. The Cogen Boilers are equipped with circulating limestone beds designed to achieve a 90% reduction in sulfur. Potential control strategies for sulfur emissions include the use of sulfur-absorbing bed compounds such as limestone or dolomite, flue gas desulfurization (FGD), acid gas scrubbers, the use of alternative fuels, and good combustion practices. Installation of add-on SO_2 controls (e.g., FGD or acid gas scrubber) are potentially technically feasible but not economically justified given the negligible SO_2 emission rate from natural gas. Natural gas has the lowest sulfur content out of the feasible auxiliary fuel stream options. Therefore, the Department finds that maintaining the existing SO_2 emission limits, use of the circulating limestone beds to achieve a 90% sulfur reduction, and the use of an inherently low sulfur fuel represents BPT for SO_2 emissions from this project.

c. Nitrogen Oxides (NO_x)

NO_x emissions from gas boilers are primarily due to thermal and prompt NO_x generation mechanisms because the fuel does not contain appreciable amounts of organonitrogen compounds that result in fuel NO_x emissions. The circulating bed design of Cogen Boilers #6 and #7 incorporates cyclonic mechanics to promote complete combustion at relatively low combustion temperatures as a mechanism for minimizing NO_x emissions. In addition, the new natural gas burners will be low-NO_x burners in design. The use of low-NO_x burners along with proper maintenance, tuning, and combustion air design will effectively minimize NO_x emissions from natural gas combustion in the boilers. The Department finds that a NO_x emission limit of 0.15 lb/MMBtu, based on boiler manufacturer estimates, in conjunction with these efforts represents BPT for NO_x emissions from firing natural gas in these boilers.

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

There are two potential categories of available control technologies for minimizing CO and VOC emissions from gas-fired boilers: combustion control strategies that minimize the formation of CO and VOC in the combustion unit and post-combustion add-on pollution control devices designed to remove and/or destroy the CO and VOC contained in the unit's exhaust stream. Potential post-combustion add-on devices include oxidation catalysts and thermal oxidizers.

Thermal oxidation is not technically feasible for controlling CO and VOC emissions from Cogen Boilers #6 and #7 due to the lower temperatures of the exhaust stream. Applying thermal oxidation would require the combustion of a considerable amount of fuel to achieve the elevated temperature necessary to promote the oxidation of the CO and VOC present in the exhaust stream. This fuel combustion would generate additional combustion pollutants, including additional CO.

Oxidation catalysts are generally a technically feasible control option for minimizing CO and VOC emissions from gas-fired boilers. However, the Cogen Boilers are designed to primarily combust solid fuel, and CFBs require bed material to be circulated continuously for proper combustion and heat transfer. During startup of these units, a significant amount of time is spent loading the bed material to facilitate a smooth startup. Combustion of oil primarily takes place during start up until the units can sustain combustion of solid fuels without the auxiliary fuel. During these start up periods, the ESPs do not function at maximum efficiency due to fuel gas characteristics. These conditions would cause rapid catalyst fouling, abrasion, and deactivation, resulting in high maintenance costs and frequent catalyst replacement. Furthermore, due to the inherently efficient combustion characteristics of CFB boilers, baseline CO and VOC emissions are already low, and additional reductions would be minimal. As there are no known commercial applications of oxidation catalysts on CFB boilers, this technology is not technically feasible for this source type.

Good combustion practices are the only control technology determined to be technically feasible for controlling CO and VOC emissions from Cogen Boilers #6 and #7. The Department finds that maintaining the current CO and VOC emission limits in conjunction with good combustion practices represents BACT for CO and VOC emissions.

e. Emission Limits

The BACT (for PM, PM_{10}, $PM_{2.5}$, CO, and VOC) and BPT (for NOx and SO2) emission rates used to determine the potential actual emissions increase for Recovery Boiler C were based on the following:

Natural Gas

PM	–	7.6 lb/MMscf based on AP-42 Table 1.4-2 dated 7/98
$PM_{10}/PM_{2.5}$	–	7.6 lb/MMscf based on AP-42 Table 1.4-2 dated 7/98
SO_2	–	0.6 lb/MMscf based on AP-42 Table 1.4-2 dated 7/98
NO_x	–	0.15 lb/MMBtu 06-096 C.M.R. ch. 115, BPT
CO	–	84 lb/MMscf based on AP-42 Table 1.4-1 dated 7/98
VOC	–	0.008 lb/MMBtu 06-096 C.M.R. ch. 115, BPT

As natural gas is fired as a supplemental fuel in Cogen Boilers #6 and #7, its addition will not change nor has NDP requested that any short-term emission limit specified in the facility's Part 70 license be modified. This project will not change the visible emission limits associated with Cogen Boilers #6 and #7 specified in the facility's Part 70 license.

D. 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.

E. 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. 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:

- Operating at the worst-case lb/hr emission limit for 8,760 hr/year for Power Boiler #3, Cogen Boilers #6 and #7, the Lime Kiln, Recovery Boiler C, Smelt Tank C, and R-10 Dryers #1 - #4;
- A heat input limit of 812,808 MMBtu/year for all building heaters combined;
- Worst-case emissions from the paper machines and pulp dryer as outlined in A-214-77-18-A (11/18/2020);
- Operating each emergency stationary engine for 100 hr/year; and
- Operation of the Lime Kiln Auxiliary Drive for 8,760 hr/year.

This information does not represent a comprehensive list of license restrictions or permissions. That information is provided in the Order section of this license, previously issued NSR licenses, and the facility's Part 70 license and amendments to that license.

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

Unit	PM	PM_{10}	SO_2	NO_x	CO	VOC
Cogen Boiler #6	82.8	82.8	772.6	1,655.60	1,090.00	22.1
Cogen Boiler #7	82.8	82.8	772.6	1,655.60	1,090.00	22.1
Power Boiler #3	65.7	65.7	341.6	525.60	262.80	19.7
Lime Kiln	105.1	105.1	100.7	227.8	170.8	8.8
Recovery Boiler C	379.7	284.7	903.6	941.7	972.4	16.2
Smelt Tank C	70.1	69.2	24.1	–	–	–
Bleach Plant	–	–	–	–	–	27.8
Paper Machines & Pulp Dryer (combined)	15.0	33.7	–	–	–	197.0
R10 Dryers	15.2	15.2	0.1	19.6	2.7	0.7
Building Air Heaters	2	2	0.2	40.6	40.6	2.2
Cogen Emergency Generator	0.1	0.1	0.1	1.6	0.4	0.1
R15 Emergency Generator	0.1	0.1	0.1	1.4	0.3	0.1
Mill Emergency Diesel Generator	0.2	0.2	0.1	4.4	1.2	0.1
Diesel Fire Water Pump	0.1	0.1	0.1	1.8	0.4	0.1
Lift Pump Emergency Generator	0.1	0.1	0.1	2.1	1.1	2.1
Lime Kiln Auxiliary Drive	0.1	0.1	0.1	0.3	0.1	0.1
ClO_2 Emergency Generator	–	–	–	0.3	0.1	–
Total TPY	**819.1**	**741.9**	**2,916.1**	**5,078.4**	**3,632.9**	**319.2**

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-214-77-21-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) **Recovery Boiler C**

A. Recovery Boiler C is licensed to fire natural gas in addition to the fuels for which it is already licensed. [06-096 C.M.R. ch. 115, BPT]

B. Recovery Boiler C shall be equipped with Low-NO_x burners for the combustion of natural gas. [06-096 C.M.R. ch. 115, BPT]

C. NDP shall equip and operate an ESP on Recovery Boiler C for control of PM emissions. [06-096 C.M.R. ch. 115, BPT]

(2) **Cogen Boilers #6 and #7**

A. Cogen Boiles #6 and #7 are licensed to fire natural gas in addition to the fuels for which they are already licensed. [06-096 C.M.R. ch. 115, BPT]

B. NDP shall equip and operate an ESPs on both Cogen Boilers #6 and #7 for control of PM emissions. [06-096 C.M.R. ch. 115, BPT]

C. Emissions of NO_x from Cogen Boilers #6 and #7 shall each not exceed 0.15 lb/MMBtu on a one-hour basis when firing only natural gas. [06-096 C.M.R. ch. 115, BPT]

Note: This emission limit does not supersede any emission limit or averaging period as found in the facility's Part 70 operating license.

(3) Approval to construct shall become invalid if the source has not commenced construction within eighteen (18) months after receipt of such approval or if construction is discontinued for a period of eighteen (18) months or more. The Department may extend this time period upon a satisfactory showing that an extension is justified but may condition such extension upon a review of either the control technology analysis or the ambient air quality standards analysis, or both. [06-096 C.M.R. ch. 115]

(4) NDP 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 requested operation. [06-096 C.M.R. ch. 140 § 1(C)(8)]

DONE AND DATED IN AUGUSTA, MAINE THIS 10th DAY OF APRIL, 2026.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY:____for______

MELANIE LOYZIM, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: 11/17/25
Date of application acceptance: 11/25/25

This Order prepared by Chris Ham, Bureau of Air Quality.