STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

PAUL R. LEPAGE
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COMMISSIONER

GNP East, Inc.
GNP Maine Holdings, LLC
Penobscot County
East Millinocket, Maine
A-405-77-2-A

Departmental
Findings of Fact and Order
New Source Review
NSR #2

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 M.R.S.A., Section 344 and Section 590, the Department finds the following facts:

I. REGISTRATION

A. Introduction

FACILITY	GNP East, Inc., Great Northern Paper Company, LLC, and GNP Maine Holdings, LLC (co-licensee)
LICENSE TYPE	06-096 CMR 115, Minor Modification
NAICS CODES	322122
NATURE OF BUSINESS	Paper Mill
FACILITY LOCATION	Main Street, East Millinocket, Maine

GNP East, Inc. and co-licensees Great Northern Paper Company, LLC and GNP Maine Holdings, LLC (hereafter collectively called GNP East) owns and operates an integrated pulp and paper manufacturing facility in East Millinocket, Maine. The plant's thermal energy and a portion of the electric power used on site are provided by on-site steam plant boilers firing biomass and/or fuel oil. Steam from the plant is used in the paper manufacturing process and for building heat.

GNP East has the potential to emit more than 100 tons per year (TPY) of particulate matter (PM), Particulate Matter under 10 micrometers (PM_{10}), particulate matter under 2.5 micrometers ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC) and more than 100,000 tons per year of carbon dioxide equivalent (CO_2e); therefore, the source is a major source for criteria pollutants. Based on 2011 annual emissions reported by this source, GNP East has the potential to emit more than 10 TPY of a single hazardous air pollutant (HAP) and more than 25 TPY of combined HAP; therefore, the source is a major source for HAP.

B. New Source Review (NSR) License Description

GNP East was issued their initial Part 70 Air Emission License (A-405-70-A-I) on November 13, 2002, licensing the operation of air emission sources associated with their integrated pulp and paper manufacturing facility. The following licensing actions have since ensued:

Date of Issuance	License Number	Licensing Action
February 3, 2003	A-405-70-B-M	502(b)(10) change
April 28, 2003	A-405-70-C-T	Transfer
May 22, 2003	A-405-70-D-M	Minor Modification
April 27, 2004	A-405-70-E-A	Part 70 Significant Modification
February 23, 2007	A-405-70-F-A	Part 70 Significant Modification
(not yet issued)	A-405-70-G-R	Part 70 License Renewal (application received March 19, 2007)
December 14, 2009	A-405-77-1-M	NSR Minor Revision
September 21, 2011	A-405-70-H-T	Transfer
December 10, 2012	A-405-70-J-M	Minor Revision (inclusion of co-licensee)

GNP East has requested the licensing of a modification at the facility to add the capability of firing natural gas in Power Boiler #2 (EB2).

C. Emission Equipment

The following equipment is addressed in this NSR license:

Equipment	Max. Capacity (MMBtu/hr)	Max. Firing Rate	Fuel Type, % sulfur	Year of Installation	Stack #
Power Boiler #2 (EB2)	374.9	2467 gal/hour	No. 6 Fuel Oil (1.5%) No. 2 Fuel Oil (0.5%)	1953	2
		0.372 MMscf/hour	Natural Gas (negligible sulfur content)		

GNP East shall utilize two Grit Industries Model 770 or equivalent natural gas line heaters rated at 0.77 MMBtu/hour each firing natural gas to heat the fuel before it is transferred to EB2. These units are below threshold levels for inclusion in licensing requirements and are mentioned here for completeness purposes only.

D. Application Classification

The application for the licensing of a modification at the facility to add the capability of firing natural gas in EB2 does not violate any applicable federal or state requirements and does not reduce required monitoring, reporting, testing, or recordkeeping. This application includes a Best Available Control Technology (BACT) analysis performed per New Source Review (NSR) requirements.

A modification at a Major Stationary Source is identified as a major or a minor modification based on whether or not projected net emissions increases exceed the "Significant Emission Increase" levels as given in *Definitions Regulation*, 06-096 CMR 100 (as amended).

Net emission increases have been determined by subtracting the average rate, in tons/year, at which the emission unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete license application is received by the Department (baseline actual emissions) from the future potential to emit. GNP East selected the years 2004 and 2005 as baseline years due to their representative nature.

The results of this analysis are as follows:

Pollutant	**Baseline Average Actual Emissions (1/04 – 12/05) (ton/year)**	**Future Potential Emissions – based on fuel limits – (ton/year)**	**Net Change (ton/year)**	**Significance Level (ton/year)**
PM	31.22	30.23	(0.99)	25
PM_{10}	31.22	30.23	(0.99)	15
$PM_{2.5}$	22.75	30.23	7.48	10
SO_2	575.52	588.62	13.1	40
NO_x	117.17	153.17	36.00	40
CO	12.91	95.4	82.49	100
VOC	1.96	8.35	6.39	40
CO_2e	64,903	65,135	232	75,000

Note: The above values are specific to EB2 only. No other emission units at the facility are affected by this NSR license.

This modification to EB2 is determined to be a minor modification under *Minor and Major Source Air Emission License Regulations* 06-096 CMR 115 (as amended) based on the following findings:

- The changes being made are not addressed or prohibited in the existing Part 70 air emission license.
- No net change in tons per year emissions for any pollutant will exceed the significance level, as demonstrated above.

- 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 the requested operation.

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 CMR 100 (as amended). 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 CMR 100. BACT is a top-down approach to selecting air emission controls considering economic, environmental, and energy impacts.

B. Project Description

1. Boiler Background

GNP East operates EB2 to generate steam for use in the paper manufacturing process and for building heat. EB2 is a Combustion Engineering model number VU-50 manufactured in 1953. It was designed with a maximum input rating of 370 MMBtu/hour and maximum firing rate of 2467 gallons/hour and fires No. 6 fuel oil (primary fuel) and No. 2 fuel oil (optional start-up fuel). Low NO_x burners and a Foxboro IA Digital Control System were installed on EB2 in 1994-1995. Emissions from this boiler exhaust through a 169-ft. above ground level (AGL) stack. With the modification described in this NSR license, this boiler will also be licensed to fire natural gas and have an increased input rating of 374.9 MMBtu/hour.

2. Proposed Modification

Once implemented, the conversion of EB2 to natural gas firing capability will allow GNP East to fire natural gas as the primary fuel in the unit. Fuel oil will be the backup fuel in case of disruptions to the natural gas supply. GNP will receive compressed natural gas (CNG) by truck, but may opt to supply natural gas to the boiler via a natural gas pipeline, should this option become available. CNG will be decompressed at the storage area from 3600 pounds per square inch-gauge (psig) to 100 psig and heated using a natural gas-fired heater, then piped to the steam plant, and finally to the burner fronts via valve trains, arriving at approximately 40 psig. The burners themselves are to be modified to include new natural gas spuds but using the existing oil guns and igniters. Total heat input for the modified burners' configuration will be 374.9 MMBtu/hour.

GNP East shall limit natural gas and fuel oil use in the boiler to maintain emissions below the emission limits contained in this license. Monthly fuel use data and emission factors will be used to demonstrate compliance with emission limits. At such time as stack testing is conducted on EB2, factors developed based on the results of stack testing showing compliance with the licensed emission limits shall be the basis for calculating emissions for ongoing compliance demonstration.

3. Annual Average Capacity Factor

According to 06-096 CMR 117, *Source Surveillance – Emissions Monitoring,* boilers that are operated at an annual average capacity factor of less than 30%, projected to remain at less than 30%, and limited to such by a federally enforceable license condition are not required to continuously monitor for opacity or for nitrogen oxides (NO_x) emissions. Annual average capacity factor is the ratio of the actual heat input to a steam generating unit from fuels fired during a calendar year to the potential heat input to the unit if it had been operating 8760 hours per year at its maximum steady state design heat input capacity. The operation of EB2 is limited by a federally enforceable license condition to an annual average capacity factor of less than 30%. This cap shall remain in effect after the conversion to natural gas.

Fuel use at maximum capacity without operational limits would be 21,608,000 gallons per year fired in EB2. Operating at 30% capacity, #6 fuel oil use in EB2 would be 6,482,400 gallons per year. In the application for conversion of this boiler to natural gas, GNP East has proposed as BACT that fuel oil usage in EB2 be limited to 4,998,905 gallons/year of No. 6 fuel oil and No. 2 fuel oil, combined.

Operating at 30% capacity, natural gas usage in EB2 would be approximately 977.6 MMscf/year. The facility has proposed a natural gas usage limit of 795,038 MMBtu/year, the equivalent of approximately 779.5 MMscf/year. Both of the fuel use caps proposed in the application are less than the 30% cap; the Department therefore accepts the proposed limits as meeting the requirements of 06-096 CMR 117, *Source Surveillance – Emissions Monitoring,* for limiting the annual average capacity factor of the unit.

4. Annual Fuel Use Limits

GNP East shall maintain records of fuel use for EB2 for each calendar year to document fuel oil use less than 4,998,905 gallons/year if firing only fuel oil; to document natural gas use of 779.5 MMscf/year if firing only natural gas; or to document a combined use of fuels not to exceed the following:

- 30% of the maximum annual potential of the boiler in MMBtu/year; and
- the tons/year limits as contained in this license.

C. BACT Determination

The following is a summary of the BACT determination for EB2, by pollutant.

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

Particulate matter emissions from the combustion of fossil fuels usually result from incomplete combustion or improper operation and maintenance. There are many control technologies available for reducing particulate emissions, including baghouses, thermal oxidation, electrostatic precipitators, wet scrubbers, and cyclones. Units firing fuels with low ash content and high combustion efficiency exhibit low particulate matter emissions. For such an application as firing natural gas in EB2, add-on controls are cost prohibitive.

The most stringent PM/PM_{10}/$PM_{2.5}$ control method demonstrated for boilers is the use of low ash fuel such as natural gas. In addition, GNP East limits the annual operating capacity of EB2 to no more than 30%.

The Department finds good combustion controls with a limit of 0.05 lb/MMBtu, equivalent to 51 lb/MMscf, constitute BACT for PM, PM_{10}, and $PM_{2.5}$ emissions from EB2 firing natural gas.

2. Sulfur Dioxide (SO_2)

Sulfur dioxide is formed from the oxidation of sulfur in fuel. The options to control SO_2 emissions from fuel combustion include low sulfur fuel and add-on treatment of the combustion exhaust gases.

Based on review of the RACT/BACT/LAER Clearinghouse (RBLC), EPA's AP-42 database, and other Maine DEP air licenses, add-on controls for SO_2 emissions from boilers of similar size firing natural gas were not identified. Due to the inherently low sulfur content of natural gas, additional SO_2 control from natural gas combustion is not economically feasible.

The Department finds good combustion controls with a limit of 0.61 lb/MMscf constitute BACT for SO_2 emissions from EB2 firing natural gas.

3. Nitrogen Oxides (NO_x)

   Formation of nitrogen oxides occurs by three different mechanisms. The formation of thermal NO_x arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) in the combustion air. Prompt NO_x is formed through the early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals in the fuel. The third type is fuel-bound NO_x.

   Add-on pollution control technologies for the reduction of NO_x emissions from the boiler include selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). These systems are costly and require the use of urea or ammonia, resulting in emissions of these compounds. Since GNP East plans to utilize its natural gas burners at less than 30% of their annual capacity, these add-on technologies are not economically justifiable.

   Review of recent, similar projects did not identify any required add-on controls. GNP East proposed low-NO_x burners and limiting the boiler to less than 30% capacity as BACT.

   The Department finds the use of low-NO_x burners and good combustion controls with a limit of 244.8 lb/MMscf constitute BACT for NO_x emissions from EB2 firing natural gas.

4. Carbon Monoxide (CO)

   The formation of CO occurs as a result of incomplete combustion of the fuel. CO emissions can be controlled through combustion control or add-on technology. Combustion control practices include a number of strategies to minimize CO emissions, including maintaining optimal fuel/air ratios, temperatures, pressure, etc. The designs of the burner systems also help assure efficient mixing of fuel and air to promote complete combustion and minimize CO emissions. Control of CO is accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion zone to ensure complete combustion.

   Technologically feasible CO emission add-on controls include use of an oxidation catalyst and thermal oxidation. Oxidation catalysts typically include the use of precious metals to reduce the temperature at which CO oxidizes and becomes CO_2. These systems can foul in the presence of particulates in the exhaust stream, however, and are not technically feasible for EB2 due to the challenges of placing and maintaining the catalyst systems in the proper temperature range locations. Thermal oxidizers act by promoting further oxidation through high temperatures, usually after particulate control. These systems require additional fuel use on an already constricted fuel source, resulting in collateral emissions of other pollutants. Additionally, the use of add-on control technology would pose a prohibitive economic burden for GNP East.

The facility proposes good combustion control practices utilizing the distributed control system (DCS) for the operation of the boiler consistent with the burner supplier's recommendations as BACT for CO emissions from EB2 firing natural gas.

The Department finds that good combustion controls with a limit of 244.8 lb/MMscf constitutes BACT for CO emissions from EB2 firing natural gas.

5. Volatile Organic Compounds (VOC)

As with CO, VOCs are emitted from boilers firing natural gas as a result of incomplete combustion of fuel in the form of unburned hydrocarbons. Control of VOCs can be accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion.

The Department finds the use of good combustion controls with a limit of 21.42 lb/MMscf constitutes BACT for VOC emissions from EB2 firing natural gas.

6. Greenhouse Gases (GHG)

Greenhouse gases are considered regulated pollutants as of January 2, 2011, through 'Tailoring' revisions made to EPA's *Approval and Promulgation of Implementation Plans,* 40 CFR Part 52, Subpart A, §52.21 Prevention of Significant Deterioration of Air Quality rule. Greenhouse gases, as defined in 06-096 CMR 100 (as amended), are the aggregate group of the following gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For purposes of licensing, GHG are calculated and reported as carbon dioxide equivalents (CO_2e).

Greenhouse gas (GHG) emissions from fossil fuel fired boilers such as EB2 result from combustion of carbon compounds contained in fuels such as residual fuel oil and natural gas. In general, fuels that contain less carbon on a calorific value basis (i.e., pounds of carbon per MMBtu) result in lower GHG emissions levels. This is illustrated by comparison of the following EPA published GHG emissions factors for various fuels:

Fuel	GHG Emission Rate (lb/MMBtu)
Natural Gas	117.1
Distillate Oil	161.4
Residual Oil	173.9

Thus, firing "cleaner" fuels is one method to reduce potential GHG emissions. GNP has also reviewed the guidance document published by the Environmental Protection Agency (EPA) titled "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial and Institutional Boilers" (EPA, October 2010). This document confirms that GNP East's proposed use of natural gas in place of fuel oil in boiler EB2 is one effective means of controlling GHG emissions. The document further identifies measures such as burner tuning and optimization and the use of effective instrumentation and controls as combustion practices that help minimize GHG emissions, along with various equipment upgrades and retrofit measures that improve efficient use of fuels. The EPA document notes that applications of post-combustion technologies to capture and sequester GHG emissions have not been demonstrated in practice on boilers such as EB2. Following is a discussion of potentially viable measures to minimize GHG emissions from the proposed project.

Combustion of Clean Fuels

Combustion of fuels that are lower in carbon content minimizes the emissions of GHG. By choosing to burn natural gas, GNP East has chosen the lowest carbon content fossil fuel available, which will result in appreciably decreased GHG emissions per unit of energy basis compared to fuel oil.

Combustion Control Practices

Combustion control practices include a number of activities plant operators can perform to minimize GHG emissions, including maintaining optimal fuel/air ratios, temperatures, pressure, etc. The design of the burners and control systems also help assure efficient mixing of fuel and air to promote complete combustion and efficient use of fuels, thus minimizing GHG emissions per unit of energy produced. GNP East's equipment providers have designed the natural gas burners and associated control systems to maximize the efficient use of the natural gas that will be used as fuel.

Add-On Controls

Carbon capture and storage (CCS) involves separation and capture of CO_2 from the flue gas, pressurization of the captured CO_2, transportation of the CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. This process, not a proven technology on a commercial basis, is neither physically nor economically viable for this facility and has been eliminated from further consideration.

Boiler System Upgrades and Retrofits
Various measures to improve the efficient use of energy produced in the combustion process, such as adding insulation and heat recovery systems, help to minimize the amount of fuel combusted and resulting GHG emissions. Boiler EB2 is already equipped with effective heat recovery systems such as a combustion air pre-heater and economizer to heat boiler feedwater. The boiler systems are also well insulated and maintained. GNP East does not believe that modifications or upgrades to these elements of the boiler would result in fuel use or GHG emissions reductions that would justify the associated capital expenditures.

Summary
GNP East proposes as BACT for GHG the selection of natural gas as the primary fuel for EB2 and maintaining sound combustion control practices.

Based on the above information, the Department finds maintaining sound combustion control practices is BACT for GHG emissions from EB2 firing natural gas.

D. Emission Limits

Emission limits for EB2 firing No. 6 fuel oil and No. 2 fuel oil are as previously licensed and have not been changed in this amendment.

BACT emission limits for EB2 firing natural gas are based on firing 372,000 scf/hr of natural gas and the following:

PM – 0.05 lb/MMBtu; burner vendor data
PM_{10} – 0.05 lb/MMBtu; burner vendor data
$PM_{2.5}$ – 0.05 lb/MMBtu; burner vendor data
SO_2 – 0.0006 lb/MMBtu; AP-42, Table 1.4-2 (dated 7/98)
NO_X – 0.24 lb/MMBtu; burner vendor data
CO – 0.24 lb/MMBtu; burner vendor data
VOC – 0.021 lb/MMBtu; burner vendor data
Opacity – 06-096 CMR 101

The BACT emission limits for EB2 firing natural gas are the following:

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 EB2 (374.9 MMBtu/hr) natural gas	18.75	18.75	18.75	0.23	90.0	90.0	7.87

When firing natural gas, visible emissions from EB2 shall not exceed 10% opacity on a six-minute block average basis, except for no more than one six-minute block average in a three-hour period.

Prior to January 1, 2018, the fuel oil fired in EB2 shall be #6 fuel oil with a maximum sulfur content of 1.5% by weight. Per 38 MRSA §603-A(1) and (2), beginning January 1, 2018, #6 fuel oil fired at the facility shall not exceed a maximum sulfur content limit of 0.5% by weight.

Prior to January 1, 2016, the #2 fuel oil fired in EB2 shall be ASTM D396 compliant #2 fuel oil (maximum sulfur content of 0.5% by weight). Per 38 MRSA §603-A(2)(A)(3), beginning January 1, 2016, the facility shall fire #2 fuel oil with a maximum sulfur content limit of 0.005% by weight (50 ppm), and beginning January 1, 2018, the facility shall fire #2 fuel oil with a maximum sulfur content limit of 0.0015% by weight (15 ppm).

E. Periodic Monitoring

Periodic monitoring for EB2 shall include recordkeeping to document fuel oil use and natural gas use on both a monthly and a 12-month rolling total basis.

F. NESHAPs: 40 CFR Part 63, Subpart DDDDD

Power Boiler EB2 will be subject to the applicable requirements of 40 CFR Part 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*, once the final version of this Subpart has been promulgated and in accordance with the compliance dates as published in the Federal Register. This unit is defined pursuant to 40 CFR Part 63, Subpart DDDDD as an existing industrial boiler in the "unit designed to burn liquid" and "unit designed to burn heavy liquid" subcategories and located at a major source of HAP emissions. As such, EB2 is subject to the following:

Specific Applicable Requirements	As Found In Part 63, Subpart DDDDD...
Emission Limits	§63.7500 and Table 2 (#14 and #15)
Work Practice Standards	§63.7500 and Table 3 (#4)
Operating Limits	§63.7500 and Table 4 (#7 and #8)
Performance Test Requirements	§63.7520 and Table 5
Fuel Analysis Requirements	§63.7521 and Table 6
Reporting Requirements	§63.7550 and Table 9

G. Incorporation into the Part 70 Air Emission License

1. The requirements in this 06-096 CMR 115 New Source Review license shall apply to the facility upon license issuance.

2. Per *Part 70 Air Emission License Regulations*, 06-096 CMR 140 (as amended), Section 1(C)(8), following the issuance, under the NSR provisions of 06-096 CMR 115, of a major or minor modification NSR license to a major stationary source, the source must apply, within one year of commencing the proposed operations, for an amendment to the Part 70 license to incorporate the NSR license requirements, as provided in 40 CFR Part 70.5.

H. Annual Emissions

1. Fuel Limits and Annual Emissions

Because emissions are dependent on the fuel being fired, and GNP East wishes to retain licensed capability to fire No.6 fuel oil and No. 2 fuel oil when CNG is not available, the facility shall be restricted to the maximum annual emissions from the fuel which gives the highest tons per year quantity for each pollutant. The tons per year of pollutants from natural gas combustion in EB2 were calculated based on annual natural gas use equivalent to 795,038 MMBtu/year (using fuel heat content of 1020 Btu per scf). The tons per year limits of pollutants from No. 6 fuel oil combustion were calculated based on 4,998,905 gallons/year of No. 6 fuel oil fired in with a sulfur content not to exceed 1.5% by weight.

The resulting annual emission limits for the facility based on a 12-month rolling total are as follows:

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

	PM	PM_{10}	SO_2	NO_x	CO	VOC
EB1	87.5	87.5	763.3	129.7	16.2	2.5
EB2	**30.2**	**30.2**	**588.6**	**153.2**	**95.4**	**8.4**
EB3	327.2	327.2	1650.4	872.5	1308.7	37.2
EGR-V6	0.2	0.2	0.1	5.2	1.1	0.4
EWWTP-S2	0.2	0.2	0.001	2.3	0.5	0.2
Total TPY	**445.3**	**445.3**	**3002.4**	**1159.7**	**1421.9**	**48.7**

2. Greenhouse Gases

Greenhouse gases are considered regulated pollutants as of January 2, 2011, through 'Tailoring' revisions made to EPA's *Approval and Promulgation of Implementation Plans,* 40 CFR Part 52, Subpart A, §52.21 Prevention of Significant Deterioration of Air Quality rule. Greenhouse gases, as defined in 06-096 CMR 100 (as amended), are the aggregate group of the following gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. For licensing purposes, greenhouse gases (GHG) are calculated and reported as carbon dioxide equivalents (CO_2e).

Based on the facility's fuel use limits, the worst case emission factors from AP-42, IPCC (Intergovernmental Panel on Climate Change), and *Mandatory Greenhouse Gas Reporting*, 40 CFR Part 98, and the global warming potentials contained in 40 CFR Part 98, GNP East is above the major source threshold of 100,000 tons of CO_2e per year.

III. AMBIENT AIR QUALITY ANALYSIS

GNP East previously submitted an ambient air quality analysis as part of the initial Part 70 license, A-405-70-A-I (issued November 13, 2002), demonstrating that emissions from the facility, in conjunction with all other sources, do not violate ambient air quality standards. An additional ambient air quality analysis is not required for this minor modification.

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 Air Emission License A-405-77-2-A pursuant to the preconstruction licensing requirements of 06-096 CMR 115 and subject to the standard and specific conditions below.

Severability. The invalidity or unenforceability of any provision, or part thereof, of this License 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) **Power Boiler #2 (EB2)**

A. GNP East is licensed to fire either fuel oil (No. 6 or No. 2) or natural gas as the primary fuel in Power Boiler #2 (EB2). [06-096 CMR 115, BPT]

B. Natural gas use in EB2 shall not exceed 779.5 MMscf per year, the equivalent of 795,038 MMBtu per year at 1020 Btu/scf. Compliance shall be demonstrated by fuel records from the supplier showing the quantity and type of fuel used. Records of annual fuel use shall be kept on a monthly and a 12-month rolling total basis. [06-096 CMR 115, BACT]

C. GNP East shall maintain records of fuel use for EB2 for each calendar year to document fuel oil use of less than 4,998,905 gallons/year if firing only fuel oil; to document natural gas use of less than 779.5 MMscf/year if firing only natural gas; or to document a combined use of fuels not to exceed the following:

1. 30% of the maximum annual potential of the boiler in MMBtu/year; and

2. The following tons/year emission limits for EB2:

PM	**PM_{10}**	**SO_2**	**NO_x**	**CO**	**VOC**
30.2	30.2	588.6	153.2	95.4	8.4

D. Emissions from EB2 shall not exceed the following when firing natural gas as the primary fuel [06-096 CMR 115, BPT]:

Unit	**PM, lb/hr**	**PM_{10}, lb/hr**	**SO_2, lb/hr**	**NO_x, lb/hr**	**CO, lb/hr**	**VOC, lb/hr**
Boiler EB2 374.9 MMBtu/hr, natural gas	18.75	18.75	0.23	90.0	90.0	7.87

E. When firing natural gas, visible emissions from EB2 shall not exceed 10% opacity on a six-minute block average basis, except for no more than one six-minute block average in a three-hour period.

F. Prior to January 1, 2018, the #6 fuel oil fired in EB2 shall have a maximum sulfur content of 1.5% by weight.

G. Per 38 MRSA §603-A(1) and (2), beginning January 1, 2018, #6 fuel oil fired at the facility shall not exceed a maximum sulfur content of 0.5% by weight.

H. Prior to January 1, 2016, #2 fuel oil fired at the facility shall be ASTM D396 compliant (max. sulfur content of 0.5% by weight). [06-096 CMR 115, BPT]

I. Beginning January 1, 2016, #2 fuel oil fired at the facility shall have a maximum sulfur content limit of 0.005% by weight (50 ppm). [38 MRSA §603-A(2)(A)(3)]

J. Beginning January 1, 2018, #2 fuel oil fired at the facility shall have a maximum sulfur content limit of 0.0015% by weight (15 ppm). [38 MRSA §603-A(2)(A)(3)]

K. Compliance with the fuel sulfur content limits shall be demonstrated by fuel records from the supplier showing the quantity, type, and the percent sulfur of the fuel delivered. Records of annual fuel use shall be kept on a monthly and 12-month rolling total basis. [06-096 CMR 115, BPT]

L. GNP East shall comply with all restrictions and requirements applicable to EB2 as specified in 40 CFR Part 63, Subpart DDDDD, in accordance with compliance dates specified therein. These requirements shall include emission limits, work practice standards, operating limits, performance testing requirements, fuel analysis requirements, and reporting requirements.

(2) GNP East shall notify the Department within 48 hours and submit a report to the Department on a quarterly basis if a malfunction or breakdown in any component causes a violation of any emission standard (38 M.R.S.A. §605).

(3) GNP East shall submit an application to incorporate this NSR license into the Part 70 air emission license no later than 12 months from commencement of the proposed operations. [06-096 CMR 140, Section 1(C)(8)]

DONE AND DATED IN AUGUSTA, MAINE THIS 23 DAY OF January, 2013.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: Marc Allen Robert Cone for
PATRICIA W. AHO, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: November 13, 2012
Date of application acceptance: November 13, 2012

Date filed with the Board of Environmental Protection:

This Order prepared by Jane Gilbert, Bureau of Air Quality.

Filed
JAN 24 2013
State of Maine
Board of Environmental Protection