STATE OF MAINE
DEPARTMENT OF ENVIRONMENTAL PROTECTION

PAUL R. LEPAGE
GOVERNOR

PATRICIA W. AHO
COMMISSIONER

Huhtamaki, Inc.
Kennebec County
Waterville, Maine
A-416-77-1-A

Departmental
Findings of Fact and Order
New Source Review
NSR #1

After review of the air emissions license amendment 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	Huhtamaki, Inc.
LICENSE TYPE	06-096 CMR 115, Minor Modification
NAICS CODES	322299
NATURE OF BUSINESS	Molded Pulp Products Manufacturing
FACILITY LOCATION	242 College Avenue, Waterville, Maine

Huhtamaki, Inc. – Waterville is a manufacturing facility that uses recycled newsprint, food board, milk carton stock, and other similar paper materials to produce molded pulp products. Cellulose fibers are mechanically cleaned, then vacuum drawn from a liquid slurry onto pre-shaped wire dies, where they are formed, compressed, and dried into finished products. Finished products include, but are not limited to, paper plates, pizza trays, food trays, and other similar molded products. A small portion of the molded products are also laminated with a plastic film.

Huhtamaki has the potential to emit more than 100 tons per year (TPY) of sulfur dioxide (SO_2) and nitrogen oxides (NO_x); therefore, the source is a major source for criteria pollutants. Huhtamaki is not a major source of hazardous air pollutants (HAPs) because it does not have the potential to emit more than 10 TPY of a single HAP or more than 25 TPY of combined HAPs; therefore, the source is an area source for HAPs.

This amendment addresses the use of natural gas as an alternative fuel in Boiler #5, from either liquefied natural gas stored on site or from a natural gas pipeline system currently planned but not yet available in the area.

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B. Amendment Description

Huhtamaki, Inc. (Huhtamaki) was issued Air Emission License A-416-70-A-I on January 14, 2002, permitting the operation of air emission sources associated with their molded pulp products facility. The license was subsequently amended on May 28, 2004 (A-416-70-B-A), and on November 5, 2004 (A-416-70-C-A).

Huhtamaki has requested an amendment to their license to permit the firing of either No. 6 fuel oil or natural gas (NG) as the primary fuel in Boiler #5. The equipment addressed in this license amendment is located at 242 College Avenue, Waterville, Maine.

C. Emission Equipment

The following equipment is addressed in this air emission license amendment:

Fuel Burning Equipment

Equipment	Max. Capacity (MMBtu/hr)	Maximum Firing Rate	Fuel Type, % sulfur	Year of Installation	Stack #
Boiler #5	64.8	61,700 scf/hr+	NG	1966	3
		432 gal/hr	#6 fuel oil, 1.7% S*		

+ based on 1050 BTU/scf
* Propane & Diesel are used for start-up purposes. Additionally, Specification Waste Oil is mixed into the #6 fuel oil tank.

Liquid Organic Material Storage

Equipment	Capacity	Description
LNG* Storage Tank	15,000 gal	Above ground, fixed, pressure vessel, 40ft length, 10ft diameter
LNG Storage Tank	15,000 gal	Above ground, fixed, pressure vessel, 40ft length, 10ft diameter

*Liquified Natural Gas

D. Application Classification

The application for modification of Boiler #5 to allow the capability of firing natural gas in addition to firing No. 6 fuel oil as written in their current license does not violate any applicable federal or state requirements and does not reduce monitoring, reporting, testing, or record keeping requirements.

This application is being processed under the New Source Review (NSR) licensing provisions contained in *Major and Minor Source Air Emission License Regulations*, 06-096 CMR 115 (as amended). The application includes a Best Available Control Technology (BACT) analysis performed per NSR requirements.

The modification of a major source is considered a major modification if expected emissions increases exceed the "Significant Emission Increase Levels" as given in *Definitions Regulation*, 06-096 CMR 100 (as amended).

The emission increases are determined by subtracting the average actual emissions of the 24 months preceding the modification (or a 24-month period representative of normal operation) from the projected actual emissions. The results of this analysis are as follows:

Pollutant	Average Past Actual Emissions 2010/2011 (ton/year)	Projected Actual Emissions (ton/year)	Net Change (ton/year)	Significance Level (ton/year)
PM	7.0	1.9	-5.1	25
PM_{10}	6.4	1.9	-4.5	15
SO_2	258.8	0.1	-258.7	40
NO_x	36.8	38.5	1.7	40
CO	4.9	20.5	15.6	100
VOC	0.3	1.5	1.0	40
CO_2e	25,425	30,207	4782	75,000

Note: The above numbers are for Boiler #5 only. No other equipment at the facility is affected by this amendment.

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

B. Project Description

Huhtamaki operates Boiler #5 for steam and heat to support facility operations. The boiler is a Babcock and Wilcox boiler rated at 64.8 MMBtu/hr which was installed in 1966. Boiler #5 fires No. 6 fuel oil, waste oil, propane, and diesel fuel and exhausts through Stack #3. With the modification described in this license amendment, this boiler will also fire natural gas.

The conversion of Boiler #5 includes the installation of two 15,000 gallon LNG storage tanks. LNG will be delivered by truck and transferred to the storage tanks. LNG will be vaporized and conveyed via a fuel line to Boiler #5 for combustion. No. 6 fuel oil and waste oil will be used as back-up fuel for this boiler when natural gas is the primary fuel.

Boiler #5 is not subject to the New Source Performance Standards (NSPS) 40 CFR Part 60, Subpart Dc, *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*, for units greater than 10 MMBtu/hr but less than 100 MMBtu/hr for which construction, modification, or reconstruction is commenced after June 9, 1989. The project does not constitute a modification as defined in 40 CFR Part 60, Subpart B, § 60.2 *Definitions* and §60.14 because there is no increase in emissions of SO_2 or PM in lb/hr. The only pollutant with a projected lb/hr emissions increase over previous license allowed is CO, which is not a pollutant regulated by Subpart Dc.

C. BACT Determination

The following is a summary of the BACT determination for Boiler #5, by pollutant.

1. Particulate Matter (PM & PM_{10})

Units firing fuels with low ash content and high combustion efficiency exhibit low particulate matter emissions. The most stringent PM/PM_{10} control method demonstrated for boilers is the use of low ash fuel such as natural gas. The Department finds good combustion controls with a limit of 7.6 lb/MMscf constitute BACT for PM/PM_{10} emissions from Boiler #5 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 NG, additional SO_2 control from natural gas combustion is not economically feasible.

The Department finds good combustion controls with a limit of 0.6 lb/MMscf constitute BACT for SO_2 emissions from Boiler #5 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.

Options for controlling NO_x emissions from the boiler include combustion control, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), flue gas recirculation (FGR), and low-NO_x burners.

Additional control technology for the existing boiler is considered economically infeasible. Review of recent, similar projects did not identify any required add-on controls. Huhtamaki proposed as BACT a low-NO_x burner to inject the gas into fuel lean and fuel rich zones, improving combustion and minimizing NO_x emissions.

The Department finds the use of a low-NO_x burner and good combustion controls with a limit of 157.5 lb/MMscf constitute BACT for NO_x emissions from Boiler #5.

4. Carbon Monoxide (CO)

The formation of CO occurs as a result of incomplete combustion of the fuel. Control of CO is accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in higher emissions of NO_x. The firing of NG results in low emissions of CO under full load or ideal conditions, although operation at lower loads generally increases emissions because of inefficient combustion.

The CO emission controls that are technologically feasible include combustion control and use of an oxidation catalyst. Catalytic oxidation reactors for CO control operate in a relatively narrow temperature range of 700°F to 1100°F. If operating within this temperature range, CO emissions could potentially be reduced 65-90%. At lower temperatures, when CO is typically higher due to inefficient combustion, the CO conversion falls off rapidly; at higher temperatures, damage to the catalyst may occur.

Upon review of the RBLC and recent Maine air licenses, Huhtamaki found no boilers of similar size firing natural gas employing a CO control catalyst.

The Department finds that good combustion controls with a limit of 84 lb/MMscf constitutes BACT for CO emissions from Boiler #5.

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. An oxidation catalyst is an effective control for VOC emissions, with potential VOC emissions reduction of 85-90%. However, such measures are economically infeasible. 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 5.5 lb/MMscf constitutes BACT for VOC emissions from Boiler #5.

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).

Emissions of GHG from boilers result from combustion of hydrocarbons in fossil fuels such as No. 6 fuel oil and natural gas. Information on control techniques and measures that are available to mitigate greenhouse gas emissions from boilers similar to Huhtamaki's Boiler #5 is provided in an EPA White Paper, published October 2010, entitled *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Industrial, Commercial, and Institutional Boilers*. Available options specified in this document include new burners, operation and maintenance practices to maximize boiler efficiency, fuel switching, and carbon capture and storage. Huhtamaki has included new burner(s) and good operation and maintenance practices to maximize boiler efficiency as part of this license amendment. The other two options are addressed individually in the following paragraphs.

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.

This project consists of fuel switching from residual oil (No. 6 and specification waste oil) to natural gas. Considering that each fuel has different carbon content, firing different fuels results in different amounts of CO_2 emissions, as illustrated by the following typical emission factors (EIA, 2008).

Fuel	lbs/MMBtu
• Natural Gas (pipeline quality):	117.080
• Distillate oil (No. 1, 2 and 4, as well as diesel):	161.386
• Residual Oil (No. 5 and 6):	173.906

Thus, switching to natural gas from No. 6 fuel oil as a primary fuel potentially results in the formation of 33% less CO_2 on a fuel-to-fuel basis. It is noted in this EPA White Paper that plant efficiency changes due to design modifications to accommodate the firing of natural gas instead of No. 6 fuel have slight impact on CO_2e emissions compared to the impact of the fuel composition.

Finally, review of the RBLC finds no further control devices or strategies for boilers similar to Boiler #5 firing natural gas to control CO_2e emissions.

Based on the above information, the Department finds that good operation and maintenance practices to maximize boiler efficiency is BACT for GHG emissions from Boiler #5 firing natural gas.

Emission Limits

Emission rates for Boiler #5 firing No. 6 fuel oil and specification waste oil are as previously licensed and have not been changed in this amendment.

Emission rates for Boiler #5 firing natural gas are based on firing 68,000 scf/hr of natural gas and the following:

PM/PM_{10} – 7.6 lb/MMscf based on AP-42, Table 1.4-2 (date 7/98)
SO_2 – 0.6 lb/MMscf: AP-42, Table 1.4-2 (dated 7/98)
NO_X – 157.5 lb/MMscf; burner vendor data
CO – 84 lb/MMscf: AP-42, Table 1.4-1 (dated 7/98)
VOC – 5.5 lb/MMscf: AP-42, Table 1.4-2 (dated 7/98)
Opacity – 06-096 CMR 101

The BACT emission limits for Boiler #5 firing natural gas are the following:

Unit	PM, lb/hr	PM_{10}, lb/hr	SO_2, lb/hr	NO_x, lb/hr	CO, lb/hr	VOC, lb/hr
Boiler #5 (64.8 MMBtu/hr) natural gas	0.47	0.47	0.04	9.7	5.2	0.34

Opacity - When firing natural gas, visible emissions shall not exceed 10% opacity on a six (6) minute block average basis, except for no more than one (1) six (6) minute block average in a 3-hour period.

Huhtamaki shall be limited to 488.8 MMscf/yr of natural gas fired in Boiler #5.

Prior to January 1, 2018, the fuel oil fired in Boiler #5 shall be #6 fuel oil with a maximum sulfur content of 1.7% by weight. Per 38 MRSA §603-A(1) and (2), beginning January 1, 2018, the facility shall fire #6 fuel oil with a maximum sulfur content limit of 0.5% by weight.

D. Periodic Monitoring

Periodic monitoring for Boiler #5 shall include recordkeeping to document both fuel oil use and natural gas use both on a monthly and 12 month rolling total basis.

E. <u>40 CFR Part 63 Subpart JJJJJJ</u>

If Boiler #5 is operated as a gas-fired boiler, it will not be subject to *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources* (40 CFR Part 63 Subpart JJJJJJ). [40 CFR § 63.11195 (e)] A gas-fired boiler is defined by this Subpart as follows:

> any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing firing liquid fuel shall not exceed a combined total of 48 hours during any calendar year. [40 CFR § 63.11237]

Operation of Boiler #5 outside of these parameters may trigger applicability of 40 CFR Part 63 Subpart JJJJJJ. Records shall be maintained to document operation of Boiler #5 as a gas-fired boiler, as defined.

Operation of Boiler #5 such that it does not fit the definition of "gas-fired boiler" given above would cause Boiler #5 to be considered an existing industrial boiler as defined in 40 CFR §63.11237 that is located at or is part of an area source of hazardous air pollutants (HAP), as defined in §63.2. As such, Boiler #5 may be subject to 40 CFR Part 63, Subpart JJJJJJ. However, 40 CFR Part 63, Subpart JJJJJJ is currently under reconsideration by the EPA, and the potential applicability of the Subpart to this source may change, contingent upon the final specifications and requirements of the proposed amendments.

For informational purposes, a summary of the currently promulgated federal 40 CFR Part 63, Subpart JJJJJJ requirements that would be applicable to Boiler #5 is provided below. At this time, the Maine Department of Environmental Protection has not taken delegation of this area source MACT (Maximum Achievable Control Technology) rule promulgated by EPA; however, Huhtamaki's Boiler #5 may still be subject to the requirements if it is not operated as a gas-fired boiler.

a. Compliance Dates, Notifications, and Work Practice Requirements

i. Initial Notification of Compliance

An Initial Notification shall be submitted to EPA no later than September 17, 2011. [40 CFR Part 63.11225(a)(2)] or for new sources - within 120 days after the source becomes subject to the standard.

ii. Boiler Tune-Up Program – Initial and Biennial

(a) A boiler tune-up program shall be implemented to include the tune-up of applicable boilers by March 21, 2012, according to the rule currently in place. [40 CFR Part 63.11196(a)(1)] However, a No Action Assurance letter was issued by the EPA on March 13, 2012, stating that EPA will exercise its enforcement discretion to not pursue enforcement action for failure to complete the required tune-up by the stated compliance date. The rule is expected to have a future compliance date in 2013 once the final revisions are promulgated.

(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; however, the burner must be inspected at least once every 36 months. [40 CFR Part 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 CFR Part 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. [40 CFR Part 63.11223(b)(3)]
4. Optimize total emissions of CO, consistent with manufacturer's specifications. [40 CFR Part 63.11223(b)(4)]
5. Measure the concentration in the effluent stream of CO in parts per million (ppm), by volume, and oxygen in volume percent, before and after adjustments are made. [40 CFR Part 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 one week of start-up. [40 CFR Part 63.11223(b)(7)

(c) A Notification of Compliance Status shall be submitted to EPA no later than 120 days after conducting the initial boiler tune-up. [40 CFR Part 63.11225(a)(4) and 40 CFR Part 63.11214(b)]

(d) The facility shall implement a biennial boiler tune-up program after the initial tune-up and initial compliance report has been submitted.

1. Each biennial tune-up shall be conducted no more than 25 months after the previous tune-up. [40 CFR Part 63.11223(a)]
2. The biennial report shall be maintained onsite and submitted to EPA, if requested. The report shall contain the concentration of CO in the effluent stream (ppmv) and oxygen in volume percent, measure before and after the boiler tune-up, a description of any corrective actions taken as part of the tune-up of the boiler, and the type and amount of fuel used over the 12 months prior to the biennial tune-up of the boiler. [40 CFR Part 63.11223(b)(6)] The biennial compliance report shall also include the company name

and address; a compliance statement signed by a responsible official certifying truth, accuracy, and completeness; and a description of any deviations and corrective actions. [40 CFR Part 63.11225(b)]

b. Recordkeeping

Records shall be maintained consistent with the requirements of 40 CFR Part 63, Subpart JJJJJJ including the following [40 CFR Part 63.11225(c)]: copies of notifications and reports with supporting compliance documentation; 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; documentation of fuel type(s) used monthly by each boiler; the occurrence and duration of each malfunction of the boiler; and actions taken during periods of malfunction to minimize emissions and actions taken to restore the malfunctioning boiler to its usual manner of operation. Records shall be in a form suitable and readily available for expeditious review.

Notification forms and additional rule information can be found on the following website: http://www.epa.gov/ttn/atw/boiler/boilerpg.html.

F. LNG Storage Tanks

To accommodate the firing of natural gas in Boiler #5, Huhtamaki will install two 15,000 gallon LNG storage tanks. Each tank is an above ground, fixed, pressure vessel with a 10 ft diameter and 40 ft length. Because the tanks each have a capacity less than 39,000 gallons, they are not subject to 06-096 CMR 111 *Petroleum Liquid Storage Vapor Control* requirements.

The requirements of 40 CFR Part 60, Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984,* do not apply to these two LNG storage tanks because the tanks both have capacities less than 75 m^3 (19,812.9 gal).

This modification is not subject to the provisions of 40 CFR Part 68, *The Risk Management Program Rule*. The natural gas is used as a fuel and is thus exempt according to § 68.126 of this Part.

The transfer, storage, and vaporization of LNG is a closed system process with the exception of pressure relief valves, which are designed to vent only during emergency situations.

There is an additional piece of equipment used in the vaporization process of LNG; however, it does not fire any fuel and is based on natural convection of air to vaporize liquefied gas. The system is designed with six ambient vaporizers with three operating at a time. The vaporizers allow the liquid to come to ambient pressure, which converts the fuel from liquid to gas. The vaporizers are equipped with an electric heater which is designed to be activated in unusually cold weather. No additional air emissions are expected from this process.

G. Incorporation Into the Part 70 Air Emission License

The requirements in this 06-096 CMR 115 NSR amendment shall apply to the facility upon amendment issuance. Per *Part 70 Air Emission License Regulations*, 06-096 CMR 140 (as amended), Section 2(J)(2)(c), for a modification that has undergone NSR requirements or been processed through 06-096 CMR 115, the source must apply for an amendment to the Part 70 license within one year of commencing the proposed operations as provided in 40 CFR Part 70.5.

H. Annual Emissions

1. Fuel Limits and Maximum Annual Emissions

Because emissions are dependent on the fuel being fired, and Huhtamaki wishes to retain licensed capability to fire No.6 fuel oil and waste oil when NG 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 were calculated based on 488.8 MMscf/yr of natural gas fired in Boiler #5. The tons per year limits of pollutants from No. 6 fuel oil combustion were calculated based on the previously licensed limit of 3,110,400 gallons/yr of No. 6 fuel oil fired in Boiler #5 [condition (16)(H) of license amendment A-416-70-C-A] with a sulfur content not to exceed 1.7% by weight [condition (16)(B) of license A-416-70-A-I].

Annual license allowed emissions change only for CO and VOC emissions. The resulting annual emission limits for the facility based on a 12 month rolling total are as follows:

Total Annual Emissions for the Facility
(used to calculate the annual license fee)

	PM	PM_{10}	SO_2	NO_x	CO	VOC
Boilers #2, #3, and #4, combined, TPY	16.4	16.4	464.1	119.3	6.3	3.7
Boiler #5, TPY	46.7	46.7	415.1	93.3	20.5	1.5
Total, TPY	63.1	63.1	879.2	212.6	26.8	5.2

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.* "Greenhouse gases" as defined by 06-096 CMR 100 (as amended) means the aggregate group of the following gases: Carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. Greenhouse gases (GHG) for purposes of licensing 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, Huhtamaki is below the major source threshold of 100,000 tons of CO_2e per year.

III. AMBIENT AIR QUALITY ANALYSIS

Huhtamaki previously submitted an ambient air quality analysis 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 amendment.

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-416-77-1-A pursuant to the preconstruction licensing requirements of 06-096 CMR 115 and subject to the standard and special 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) **Boiler #5**

A. Huhtamaki is licensed to fire either No. 6 fuel oil or natural gas as the primary fuel in Boiler #5.

B. Natural gas use in Boiler #5 shall not exceed 488.8 MMscf/yr. Compliance shall be demonstrated by fuel records from the supplier showing the quantity and type of the fuel used. Records of annual fuel use shall be kept on a monthly and 12-month rolling total basis. [06-096 CMR 115, BPT]

C. Emissions from Boiler #5 shall not exceed the following when firing natural gas as the primary fuel [06-096 CMR 115, BPT]:

Emission Unit	**PM (lb/hr)**	**PM_{10} (lb/hr)**	**SO_2 (lb/hr)**	**NO_x (lb/hr)**	**CO (lb/hr)**	**VOC (lb/hr)**
Boiler #5	0.47	0.47	0.04	9.7	5.2	0.34

Visible emissions while firing natural gas as the primary fuel shall not exceed 10% opacity on a six (6) minute block average, except for no more than one (1) six (6) minute block average in a continuous 3-hour period. [06-096 CMR 101]

Visible emissions while firing No. 6 fuel oil as the primary fuel shall not exceed the previously licensed limit of 30% opacity on a six (6) minute block average, except for no more than three (3) six (6) minute block averages in a continuous 3-hour period. [06-096 CMR 101]

(2) Huhtamaki 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) Huhtamaki shall submit an application to incorporate this amendment into the Part 70 air emission license no later than 12 months from commencement of the requested operation. [06-096 CMR 140, Section 2(J)(2)(c)]

DONE AND DATED IN AUGUSTA, MAINE THIS 23rd DAY OF March, 2012.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: Melanie Loyzim for
PATRICIA W. AHO, COMMISSIONER

PLEASE NOTE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application: February 15, 2012
Date of application acceptance: February 21, 2012

Date filed with the Board of Environmental Protection:

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

Filed
MAR 26 2012
State of Maine
Board of Environmental Protection