STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Temporary Permit
Prevention of Significant Deterioration (PSD)
and
Non-Attainment New Source Review (NSR) Permit

Permit No: **TP-B-0531**
Date Issued: **July 25, 2007**
Significant Permit Amendment: **November 7, 2008**
Permit Reissuance: **January 22, 2010**

This certifies that:
University of New Hampshire
22 Colovos Road
Durham, New Hampshire 03824

has been granted a Temporary Permit and PSD/NSR Permit for the following facility and locations:

University of New Hampshire	**University of New Hampshire**
22 Colovos Road	**Rochester Neck Road**
Durham, New Hampshire 03824	**Rochester, New Hampshire 03839**

AFS Point Source Number (both locations) – 3301700009

New Hampshire has USEPA-approved procedures to ensure new construction or modifications of stationary sources do not violate control strategies or interfere with attainment or maintenance standards. These procedures authorize the DES to regulate significant increases for all criteria and regulated pollutants.

The joint PSD/NSR Temporary Permit is for a facility which emits air pollutants into the ambient air as set forth in equipment registration forms (ARD 1-6), filed with this Division under the date of **July 7, 2008** in accordance with RSA 125-C of the New Hampshire Laws. The PSD/NSR provisions of this permit are effective indefinitely or until such time that the facility applies and receives a Title V Operating Permit or a PSD/NSR Permit that modifies the terms and conditions of this permit. Request for permit renewal is due to the Division at least 90 days prior to expiration of this permit and must be accompanied by the appropriate permit application forms. This permit is valid upon issuance and expires on **January 31, 2011.**

SEE ATTACHED SHEETS FOR ADDITIONAL PERMIT CONDITIONS

The owner or operator of the devices covered by this permit shall submit a written request for a permit amendment to the Director at least 90 days prior to the implementation of any proposed change to the physical structure or operation of the devices covered by this permit which increases the amount of a specific air pollutant emitted by such devices or which results in the emission of any additional air pollutant. The change shall not take place until a new permit application is submitted and acted upon by the Director pursuant to Env-A 600.

Any permit deviation, which results in emissions greater than those stipulated in this permit, must be reported to the Division within 24 hours of the occurrence.

COPY

Director
Air Resources Division

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ABBREVIATIONS

AAL	Ambient Air Limit
AP-42	Compilation of Air Pollutant Emission Factors
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BHP (or bhp)	Brake Horse Power
CAA	Clean Air Act, 42 U.S.C. § 7401, et seq.
CEMS (or CMS)	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Env-A	New Hampshire Code of Administrative Rules – Air Resources Division
ERC	Emission Reduction Credit
g/bhp-hr	Grams per brake horsepower-hour
GCP	Good Combustion Practices
HAP	Hazardous Air Pollutant
HHV	High Heat Value
Hr	Hour
KW	Kilowatt
LAER	Lowest Achievable Emission Rate
Lb/hr	Pounds per hour
LFG	Landfill Gas
LFGTE	Landfill Gas to Energy Project
LNB	Low NO_x Burner
MACT	Maximum Achievable Control Technology
MMBtu	Million British Thermal Units
MMCF	Million Cubic Feet
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
NHDES (or DES)	New Hampshire Department of Environmental Services
NMOC	Nonmethane Organic Compound
NO_2	Nitrogen Dioxide
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns diameter
ppm	part per million
ppmv	part per million by volume
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RTAP	Regulated Toxic Air Pollutant
SCFM	Standard Cubic Feet per Minute
SO_2	Sulfur Dioxide
TRS	Total Reduced Sulfur
TSP	Total Suspended Particulate Matter
TPY	Tons per Year
UNH	University of New Hampshire
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

Facility Specific PSD & NSR Permit Conditions

I. Facility Description of Operations

The University of New Hampshire, Durham Campus (UNH) is an educational institution located in Durham, NH. The predominant sources of air pollutant emissions at UNH are their central heating plant, a boiler located at the New England Center, and emergency generators located throughout the university campus.

II. Project Description

UNH proposes to construct and operate a Landfill Gas to Energy (LFGTE) facility to be located at the Turnkey Landfill in Rochester, NH. Landfill gas (LFG) generated at the Turnkey Landfill will be processed and transferred by pipeline to the UNH cogeneration plant in Durham, which is located approximately twelve miles from the Turnkey Landfill. The LFGTE facility is considered a support facility to the UNH cogeneration plant and is therefore considered a modification to the existing UNH facility.

The five basic stages of the proposed LFGTE facility will be: 1) LFG gas preparation and sulfur removal; 2) electricity generation by two LFG fired internal combustion engines; 3) LFG treatment and thermal oxidation of waste gas; 4) flaring of excess LFG gas; and 5) product gas transfer to the cogeneration plant in Durham. The Durham cogeneration plant currently operates an existing 7.9 megawatt (MW) dual-fuel (distillate fuel oil and natural gas) stationary turbine with a heat input rating of 106.0 million British Thermal units per hour (MMBtu/hr), and a heat recovery steam generator (HRSG) with a natural gas fired duct burner (DB) rated at 66.3 MMBtu/hr. The existing turbine and HRSG (with DB) are currently operating under Title V Operating Permit number TV-OP-010. The applicant has applied to install a supplemental stationary gas turbine rated at 43.6 MMBtu/hr as part of this LFGTE project.

The initial stage of LFG processing consists of pressurizing the gas, lowering the gas temperature and removing moisture. The next step is to remove sulfur-bearing compounds known as total reduced sulfur compounds (TRS) from the LFG. At this point, the LFG required for operating the LFGTE facility power generation equipment and the thermal oxidizer is supplied. The remaining LFG is further compressed, additional moisture is removed, and it is treated to remove siloxanes and volatile organic compounds by use of activated carbon. Activated carbon is followed by pressure swing adsorption, which employs a molecular sieve to remove carbon dioxide.

The power generation equipment for the LFGTE facility consists of two reciprocating engines designed to operate on LFG, each capable of generating 1,600 kW of electricity. The electricity will be used to produce power for the landfill gas treatment system described above.

The thermal oxidizer will destruct the waste gas streams produced during the regeneration of the activated carbon and the pressure swing adsorption's molecular sieve. The thermal oxidizer's maximum heat input is expected to be approximately 36 MMBtu/hr. Because of the variability of the energy content of the waste gas stream, LFG will be required as a supplemental fuel for flame stabilization.

UNH has agreed to continuously take 7,000 standard cubic feet per minute (scfm) of LFG, regardless of the processing demand at the UNH campus. UNH will install two open flares to be operated for supplemental and standby purposes. Based on current energy needs at the Durham campus, the

supplemental flare will operate continuously, at an average of 12% of its rated capacity. When the processing equipment and turbines are not operating, both of the flares will operate at their maximum rated capacity to control the LFG.

The amount of excess product gas will vary on a seasonal basis such that the greatest amount of excess gas will be available in the warmer months. In order to fully utilize the product gas, UNH has applied to install a supplemental turbine at the Durham campus cogeneration facility. UNH has not made a final decision regarding the installation of a turbine, but would like to permit the proposed unit should they decide to do so. The flare load described above is based on the assumption that the turbine will be installed. If the turbine is not installed, the quantity of gas flared will increase.

In summary, the pollutant emitting equipment that require permitting include:

- Two new 1,600 kW LFG fired engines, each rated at 16 MMBtu/hr heat input rate;
- One new LFG fired supplemental turbine rated at 43.6 MMBtu/hr;
- Two new open LFG flares rated at 125.4 MMBtu/hr and 105 MMBtu/hr;
- One new thermal oxidizer rated at 36 MMBtu/hr fired by LFG and waste gases; and
- One existing 7.9 MW natural gas/distillate fuel oil fired combustion turbine rated at 106.0 MMBtu/hr with a heat recovery steam generator (HRSG) and duct burner rated at 66.3 MMBtu/hr (both fuel burning devices will be permitted to burn LFG in addition to the currently permitted fuels).

The LFGTE project is classified as a major modification to an existing major source under both the federal New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. In the application, UNH proposed the following maximum emissions in tons per year (including emissions resulting from the operation of air pollution control equipment) from the LFGTE project:

Table 1: PSD and Non-Attainment NSR Applicability

Pollutant	Program	Projected Project Emissions tons per year (tpy)	Net Emissions Increase (tpy)	Significant Emissions Threshold (tpy)[1]	Is Proposed Modification Significant? (Yes/No)
NO_x	NSR	41.52	41.52	25	Yes
NO_2	PSD	41.52	41.52	40	Yes
CO	PSD	182.0	182.0	100	Yes
TSP/PM_{10}	PSD	23.14	23.14	25/15	No/Yes (Significant for PM_{10} only)

[1] The UNH campus is an existing major source of attainment pollutants for PSD applicability purposes and is a major source of NOx for NSR applicability purposes.

Table 1: PSD and Non-Attainment NSR Applicability					
Pollutant	**Program**	**Projected Project Emissions tons per year (tpy)**	**Net Emissions Increase (tpy)**	**Significant Emissions Threshold (tpy)[1]**	**Is Proposed Modification Significant? (Yes/No)**
SO_2	PSD	39.0	39.0	40	No
VOC	NSR	48.24	48.24	25	No[2]
TRS/H_2S	PSD	0.69	0.69	10	No
Lead	PSD	<0.01	<0.01	0.6	No

III. Applicability of Federal Regulations

A. Federal Prevention of Significant Deterioration (PSD) Requirements

As shown above in Table 1, the LFGTE project will emit nitrogen dioxide (NO_2), a subset of NO_x, particulate matter less than 10 microns in diameter (PM_{10}), and CO in excess of major source PSD significant modification thresholds, and therefore is subject to PSD review and requires a PSD permit. The PSD regulations require that Best Available Control Technology (BACT) be applied to this project to minimize NO_2, PM_{10}, and CO emissions.

B. Federal Non-Attainment New Source Review (NSR) Requirements

As shown above in Table 1, the LFGTE project will emit NO_x in excess of major source NSR significant modification thresholds, and therefore is subject to NSR review and requires a NSR permit. The NSR regulations require that UNH install pollution control equipment for NO_x emissions capable of achieving the Lowest Achievable Emission Rate (LAER) for this pollutant. The NSR program also requires UNH to offset its NOx emissions at a ratio of 1.2:1, which requires UNH to obtain 50 tons of NOx emissions offsets (41.52 ton NOx increase * 1.2).

C. Federal New Source Performance Standards (NSPS) for Stationary Combustion Turbines

The Solar Mercury Combustion Turbine will be subject to the NSPS, 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines ("Subpart KKKK"). Subpart KKKK affects stationary combustion turbines with a design capacity greater than 10 MMBtu/hr constructed after February 18, 2005. The pollutants regulated under this NSPS are SO_2 and NOx.

IV. Air Quality Impact Analysis

As demonstrated by the air quality impact analysis and additional analyses required by state and federal regulations, including cavity analysis, toxic air pollutant impact assessment, and Class I impact analyses, the LFGTE project will not cause or contribute to violations of National Ambient Air Quality Standards

[2] While the proposed VOC increase is above the 25 ton per year significant modification threshold, UNH is currently a minor source of VOC under the Non-Attainment NSR Program (VOC emissions are less than 50 tons per year) and therefore does not trigger Non-Attainment NSR for this project. However, this project will result in UNH becoming a new major source of VOC and future projects will be reviewed with respect to the 25 ton per year significant modification threshold.

(NAAQS), PSD increments, or Ambient Air Limits (AALs) as regulated under Env-A 1400.

V. Permitted Activities

In accordance with all of the applicable requirements identified in this permit, UNH is authorized to construct and operate the LFGTE project and all associated ancillary equipment and processes identified in Sections VI through VIII within the terms and conditions specified in this permit.

VI. Significant Activities Identification and Stack Criteria

A. Significant Activity Identification

The activities identified in Table 2 are subject to and regulated by this Permit:

Table 2: Emission Units to be Permitted

Device	Emission Unit Number	Manufacturer, Model, Serial Number	Maximum Operating Limitations
Siemens SGT-300 Combustion Turbine (CT) (Existing unit)	EU07	Siemens Power Tempest SGT-300 S/N: N/A	1. Operation shall be limited to No. 2 fuel oil, natural gas, or processed landfill gas. 2. The maximum heat input shall be limited to: a. 104.8 MMBtu/hr while firing No. 2 fuel oil at 0°F (equivalent to 748.6 gal/hr[3]), and chiller OFF[4]; b. 106.0 MMBtu/hr while firing natural gas at 0°F (equivalent to 103,922 scf/hr[5]) and chiller OFF; and c. 106.0 MMBtu/hr while firing processed landfill gas at 0°F (equivalent to 140,957scf/hr[6]) and chiller OFF.
Heat Recovery Steam Generator (HRSG) with Duct Burner (DB) (Existing unit)	EU08	Energy Recovery International Model VC-4 Serial Number 4759 Nat Com Burner Model DBG 582R Serial Number 9511-1	1. Operation shall be limited to natural gas and processed landfill gas. 2. The maximum heat input shall be limited to 66.3 MMBTU/hr (equivalent to 65,000 scf/hr).
Reciprocating Engine #1	EU14	Caterpillar Model # G3520C Serial # TBD	1. Operation shall be limited to the combustion of unprocessed or processed landfill gas. 2. The maximum heat input shall be limited to 16.0 MMBTU/hr (equivalent to 32,000 scf/hr[7]).

[3] The hourly fuel rate is set assuming a heating value of 140,000 Btu/gal for No. 2 fuel oil. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[4] The Siemens combustion turbine has an absorption chiller to provide combustion air pre-cooling for the turbine. This operates whenever the ambient air temperature is above 70 degrees Fahrenheit and the turbine cannot meet the campus electric load.

[5] The hourly fuel rate is set assuming a heating value of 1,020 Btu/scf for natural gas. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

[6] Unless otherwise specified in this permit, all landfill gas flows are set assuming a standard temperature of 60 degrees Fahrenheit and a standard pressure of 14.7 psia.

[7] The hourly fuel rate is set assuming a heating value of 500 Btu/scf for unprocessed landfill gas. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

Table 2: Emission Units to be Permitted			
Device	**Emission Unit Number**	**Manufacturer, Model, Serial Number**	**Maximum Operating Limitations**
Reciprocating Engine #2	EU15	Caterpillar Model # G3520C Serial # TBD	1. Operation shall be limited to the combustion of unprocessed or processed landfill gas. 2. The maximum heat input shall be limited to 16.0 MMBTU/hr (equivalent to 32,000 scf/hr).
Supplemental Utility Flare	EU16	John Zink Co. Model # TBD Serial # TBD	1. Operation shall be limited to the combustion of unprocessed or processed landfill gas. 2. The maximum heat input shall be limited to 125.4 MMBTU/hr (equivalent to 250,800 scf/hr).
Standby Utility Flare	EU17	John Zink Co. Model # TBD Serial # TBD	1. Operation shall be limited to the combustion of unprocessed or processed landfill gas. 2. The maximum heat input shall be limited to 105.06 MMBTU/hr (equivalent to 210,120 scf/hr).
Thermal Oxidizer	EU18	Manufacturer TBD Model # TBD Serial # TBD	1. Operation shall be limited to the combustion of unprocessed landfill gas and waste gas produced from the regeneration of treatment media. 2. The maximum heat input to this device shall be limited to 36 MMBTU/hr.
Solar Mercury 50 Recuperative Turbine	EU19	Solar Model # Mercury 50-6000R Serial # TBD	1. Operation shall be limited to the combustion of processed landfill gas. 2. The maximum heat input shall be limited to 43.6 MMBTU/hr (equivalent to 57,978 scf/hr[8]).

B. **Stack Criteria**

The stacks listed in Table 3 shall discharge vertically without obstruction (including rain caps) and meet the following criteria:

Table 3 – Stack Criteria				
Stack Number	**Emission Unit Number**	**Emission Unit Description**	**Minimum Stack Height Above Ground Level (Feet)**	**Maximum Inside Stack Diameter (Feet)**
ST04	**EU07**	Siemens Turbine and Duct Burner (combined stack)	100	6.5
	EU08			
ST14	**EU14**	Reciprocating Engine #1	32	1.3
ST15	**EU15**	Reciprocating Engine #2	32	1.3
ST16	**EU16**	Supplemental Utility Flare	61.2 (effective stack height)	6.5 (equivalent diameter)

[8] The hourly fuel rate is set assuming a heating value of 752 Btu/scf for processed landfill gas. The fuel consumption limits may vary based on the actual heat content of the fuel burned.

Table 3 – Stack Criteria				
Stack Number	**Emission Unit Number**	**Emission Unit Description**	**Minimum Stack Height Above Ground Level (Feet)**	**Maximum Inside Stack Diameter (Feet)**
ST17	**EU17**	Standby Utility Flare	58.6 (effective stack height)	5.9 (equivalent diameter)
ST18	**EU18**	Thermal Oxidizer	30	4
ST19	**EU19**	Solar Mercury Recuperative Turbine	100	4.1

Changes to the state-only requirements pertaining to stack parameters (set forth in this permit), shall be permitted only when an air quality impact analysis which meets the criteria of Env-A 606 is performed either by the facility or the New Hampshire Department of Environmental Services, Air Resources Division (if requested by facility in writing) in accordance with the "DES-ARD Procedure for Air Quality Impact Modeling." All air modeling data shall be kept on file at the facility for review by DES upon request.

VII. Pollution Control Equipment/Method Identification

The device identified in Table 4 is considered pollution control equipment for each identified emissions unit:

Table 4 – Pollution Control Equipment/Method Identification			
Pollution Control Equipment Number	**Emission Unit Controlled**	**Description of Equipment/Method**	**Primary Pollutants Controlled**
PC1	LFG Treatment System	Thermal Oxidizer (EU18)	Waste gases generated from LFG treatment system (siloxanes, VOCs)
PC2	SulfaTreat System	Sulfur removal through reaction with iron to form iron sulfide	Sulfur in LFG
PC3	Molecular Sieve	Carbon dioxide removal via molecular sieve	Carbon Dioxide

VIII. Applicable Requirements

A. Operational and Emission Limitations

1. When EU07 or EU08 are operating on natural gas or No. 2 fuel oil, the owner or operator shall comply with all conditions set forth in Title V Operating Permit TV-OP-010 issued April 4, 2007.
2. When EU07 or EU08 are operating on processed landfill gas, the owner or operator shall comply with all applicable natural gas firing conditions set forth in Title V Operating Permit TV-OP-010 for these devices.
3. The quantity of landfill gas combusted in each device shall be limited such that the emissions limitations for each device identified in Table 5 below will be met.

Table 5 – Summary of Emission Limitations[9]

Pollutant	EU14 Reciprocating Engine #1	EU15 Reciprocating Engine #2	EU16 Supplemental Utility Flare	EU17 Standby Utility Flare	EU18 Thermal Oxidizer	EU19 Supplemental Turbine	Regulatory Citation
NOx limit	0.50 g/bhp-hr (BACT/LAER) 2.5 g/bhp-hr (NOx RACT limit – one-hour average)	0.50 g/bhp-hr (BACT/LAER) 2.5 g/bhp-hr (NOx RACT limit – one-hour average)	0.068 lb/MMBtu (BACT/LAER)	0.068 lb/MMBtu (BACT/LAER)	0.065 lb/MMBtu (N/A)	5 ppm @15% O_2 (BACT/LAER) 25 ppm @15% O_2[10] (NOx RACT limit)	Env-A 618.03(a) (LAER) Env-A 619.03(a) 40 CFR 52.21 (BACT)
NOx limit for multiple devices	41.52 tons per consecutive 12 month period for devices EU14 through EU19 combined.						
NOx LAER Control Technology	Lean Burn Design, Air/Fuel Ratio Controller, Intercooler Good Combustion Practices		Open Flare Design Good Combustion Practices		N/A	Dry Low NOx Combustion Technology Good Combustion Practices	
CO limit	2.75 g/bhp-hr (BACT)	2.75 g/bhp-hr (BACT)	0.37 lb/MMBtu (BACT)	0.37 lb/MMBtu (BACT)	0.065 lb/MMBtu (N/A)	10 ppm @15% O2(BACT)	Env-A 619.03(a) 40 CFR 52.21 (BACT)
CO limit for multiple devices	182.00 tons per consecutive 12 month period for devices EU14 through EU19 combined.						
CO BACT Control Technology	Good Combustion Practices		Good Combustion Practices		N/A	Good Combustion Practices	
SO_2 limit	0.046 g/bhp-hr	0.046 g/bhp-hr	0.149 lb/MMBtu	0.149 lb/MMBtu	0.015 lb/MMBtu	0.002 lb/MMBtu	RSA 125-C:6, XI
SO_2 limit for multiple devices	39.00 tons per consecutive 12 month period for devices EU14 through EU19 combined.						
TSP/PM10 limit[11]	0.10 g/bhp-hr (BACT)	0.10 g/bhp-hr (BACT)	0.042 lb/MMBtu (BACT)	0.042 lb/MMBtu (BACT)	0.042 lb/MMBtu (N/A)	0.042 lb/MMBtu (BACT)	Env-A 619.03(a) 40 CFR 52.21 (BACT)
TSP/PM10 limit for multiple devices	23.14 tons per consecutive 12 month period for devices EU14 through EU19 combined.						

9 The emissions limitations contained in Table 5 above are based on a 3-hour averaging period unless otherwise specified.

10 The NOx limit of 25 ppm @15% O_2 is based on the NOx RACT standard contained in Env-A 1211.06 and is more stringent than the NSPS limit of 96 ppm @15% O_2. Since both standards are based on a 1-hour averaging period, only the more stringent limit is included for streamlining purposes.

11 Both the TSP and PM10 emission limits are based on filterable particulate matter only. The TSP and PM10 limits will be re-evaluated once condensable particulate matter emissions are determined during the initial compliance stack testing.

Table 5 – Summary of Emission Limitations[9]							
Pollutant	**EU14 Reciprocating Engine #1**	**EU15 Reciprocating Engine #2**	**EU16 Supplemental Utility Flare**	**EU17 Standby Utility Flare**	**EU18 Thermal Oxidizer**	**EU19 Supplemental Turbine**	**Regulatory Citation**
TSP/PM10 BACT Control Technology	Good Combustion Practices		Good Combustion Practices		N/A	Good Combustion Practices	
VOC limit	0.70 g/bhp-hr	0.70 g/bhp-hr	0.060 lb/MMBtu	0.060 lb/MMBtu	0.065 lb/MMBtu	0.013 lb/MMBtu	RSA 125-C:6, XI
VOC limit for multiple devices	48.24 tons per consecutive 12 month period for devices EU14 through EU19 combined.						

4. The owner or operator shall be subject to the operational and emission limitations identified in Table 6 below.

Table 6: Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
1.	*Facility-Wide HAP Emission Limitation* Facility-wide emissions of Hazardous Air Pollutants (HAPs, as defined in Section 112 of the 1990 Clean Air Act Amendments) shall be limited to less than 10 tpy for any individual HAP and 25 tpy for all HAPs combined.	Facility Wide	Env-A 604.02(a)(1)
2.	*24-hour and Annual Ambient Air Limit* The emissions of any Regulated Toxic Air Pollutant (RTAP) shall not cause an exceedance of its associated 24-hour or annual Ambient Air Limit (AAL) as set forth in Env-A 1450.01, *Table Containing the List Naming All Regulated Toxic Air Pollutants*.	Facility Wide	Env-A 1400
3.	*Revisions of the List of RTAPs* In accordance with RSA 125-I:5 IV, if DES revises the list of RTAPs or their respective AALs or classifications under RSA 125-I:4, II and III, and as a result of such revision The owner or operator is required to obtain or modify the permit under the provisions of RSA 125-I or RSA 125-C, The owner or operator shall have 90 days following publication of notice of such final revision in the New Hampshire Rulemaking Register to file a complete application for such permit or permit modification.	Facility Wide	RSA 125-I:5 IV
4.	*Visible Emission Standard for Fuel Burning Devices Installed After May 13, 1970* The average opacity from fuel burning devices installed after May 13, 1970 shall not exceed 20 percent for any continuous 6-minute period.	EU07 EU08 EU14 EU15 EU16 EU17 EU18 EU19	Env-A 2002.02

Table 6: Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
5.	*Activities Exempt from Visible Emission Standards* The average opacity shall be allowed to be in excess of those standards specified in Env-A 2002.02 for one period of 6 continuous minutes in any 60 minute period during startup, shutdown, or malfunction.	EU07 EU08 EU14 EU15 EU16 EU17 EU18 EU19	Env-A 2002.04(c)
6.	*Particulate Emission Standards for Fuel Burning Devices Installed on or After January 1, 1985* The particulate matter emissions from fuel burning devices installed on or after January 1, 1985 shall not exceed 0.30 lb/MMBtu.	EU07 EU08 EU14 EU15 EU16 EU17 EU18 EU19	Env-A 2002.08
7.	*NOx RACT Emission Standard for Combustion Turbine* On and after November 1, 2002, all gas-fired turbines constructed after May 27, 1999, shall be limited to an hourly average NOx RACT emission limit of 25 ppmvd, corrected to 15% O2, or 0.092 lb. per million Btu, when operating on gas.	EU19	Env-A 1211.06(d)
8.	*NOx Emissions Standard for Stationary Combustion Turbines Subject to 40 CFR Part 60 Subpart KKKK* NOx emissions from the Solar Mercury Recuperative Turbine shall be limited to 96 ppm at 15% O_2 or 5.5 lb per MWh of useful energy output[12].	EU19	40 CFR § 60.4320
9.	*SO_2 Emissions Standard for Stationary Combustion Turbines Subject to 40 CFR Part 60 Subpart KKKK* a. SO_2 emissions from the Solar Mercury Recuperative Turbine shall be limited to 0.90 pounds per megawatt-hour (lb/MWh) gross output. b. As an alternative to item (a) above, The owner or operator may comply with this part by burning fuel containing total potential sulfur emissions less than or equal to 0.060 lb SO_2/MMBtu heat input.	EU19	40 CFR § 60.4330

[12] The NOx limit of 25 ppm @15% O_2 is based on the NOx RACT standard contained in Env-A 1211.06 and is more stringent than the NSPS limit of 96 ppm @15% O_2.

Table 6: Operating and Emission Limitations			
Item #	**Requirement**	**Applicable Emission Unit**	**Regulatory Citation**
10.	The owner or operator must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.	EU19	40 CFR § 60.4333(a)
11.	Pollution Control Equipment Operation and Maintenance: a. The combustion chamber shall be maintained at a minimum temperature of 1,280°F[13], based on an hourly average; and b. The thermal oxidizer shall be maintained in accordance with manufacturer's recommendations.	EU18	RSA 125-C:6, XI
12.	Flares shall be operated with a flame present at all times when landfill gas is delivered to the flares.	EU16 EU17	RSA 125-C:6, XI

B. **Initial Compliance Demonstration Requirements**

The owner or operator shall demonstrate initial compliance with the conditions specified in Tables 5 and 6 no later than 180 days after startup of the new affected source. The owner or operator shall perform the monitoring and/or testing indicated in Table 7.

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
1.	EU14 EU15 EU18 EU19[14]	NOx CO SO_2 TSP PM10 VOC Opacity	a. Pursuant to Env-A 802, the owner or operator shall conduct initial performance tests for SO_2, NO_x, CO, TSP, PM_{10}, VOC & opacity to demonstrate compliance with the respective emissions limitations in Tables 5 and 6. b. The following test methods or Division approved alternatives shall be used for the pollutants specified: i. Method 1 or 2 to determine exit velocity of stack gases; ii. Method 3 or 3A to determine carbon dioxide, oxygen, excess air, and molecular weight (dry basis) of stack gases; iii. Method 4 to determine moisture content (volume fraction of water vapor) of stack gases;	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility	Env-A 801.02

[13] The minimum required combustion chamber temperature may be reduced if performance testing demonstrates that the emission limits specified in this permit for EU18 will be met at the lower temperature.

[14] VOC performance testing for the Supplemental Combustion Turbine (Solar Mercury 50) is not required at this time.

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			iv. Methods 5, 201A, and 202 for total suspended particulate matter, filterable PM_{10}, and condensable PM_{10}[15]; v. Methods 6 or 6C for sulfur dioxide; vi. Method 7 for NOx; vii. Method 9 for opacity; viii. Method 10 for CO; and ix. Method 25 or 25A for total gaseous non-methane organic compound emissions.		
2.	EU14 EU15 EU18 EU19	NOx CO SO_2 TSP PM10 VOC Opacity	<u>Stack Testing Requirements:</u> a. A compliance stack emissions test shall conform to the following: i. The procedures specified in Env-A 802; ii. The general requirements of 40 CFR 60.8(a), (b), (d), (e), and (f); and iii. The test methods contained in 40 CFR 60, Appendix A, 40 CFR 51, Appendix M, or any other USEPA-promulgated stack test method.	For each required stack test	Env-A 802.02
3.	EU14 EU15 EU19	NOx	<u>Compliance Stack Testing for NOx RACT</u>: a. The owner or operator shall conduct an initial compliance stack test in accordance with Env-A 802 to demonstrate compliance with the NOx RACT emission limits contained in Env-A 1211.06 and Env-A 1211.07. b. The following test methods shall be used as applicable: i. Method 7, 7A, 7C, 7D or 7E as described in 40 CFR 60, Appendix A, to determine NOx concentrations in stack gases; ii. Method 10 as described in 40 CFR	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility. Subsequent testing every 3 years from date of previous NOx compliance stack test[16].	Env-A 803.02

[15] Both the TSP and PM10 emission limits in this permit are based on filterable particulate matter only. The TSP and PM10 limits will be re-evaluated once condensable particulate matter emissions are determined during the initial compliance stack testing.

[16] Performance testing is also required to demonstrate compliance with the NOx emission limit contained in the Code of Federal Regulations, Part 40, Subpart KKKK and Table 8, Item 9 of this permit. Performance testing under Subpart KKKK is required annually or biannually, depending on the results of the previous test. Provided that the tests are conducted in accordance with the requirements of NOx RACT, Subpart KKKK testing will also serve as the NOx RACT Compliance Test.

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			60, Appendix A, to determine carbon monoxide concentrations in stack gases; iii. Methods 1 and 2, 2C, 2F, 2G, or 2H, as described in 40 CFR 60, Appendix A, to determine the exit flow rate of stack gases; iv. Method 3 or 3A as described in 40 CFR 60, Appendix A, to determine carbon dioxide, oxygen, excess air and molecular weight, dry basis, of stack gases; and v. Method 4 as described in 40 CFR 60, Appendix A, to determine the volume fraction of water vapor in stack gases. c. The owner or operator may use Method 20 as described in 40 CFR 60, Appendix A, in lieu of the methods identified in (b) above, to determine NOx concentrations in stationary gas turbine stack gases.		
4. .	EU19	NOx and SO_2	The owner or operator shall conduct an initial performance test in accordance with 40 CFR §60.8 and 40 CFR §60.4400.	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup of such facility.	40 CFR §60.8(a)
5.	EU19	NOx	There are two general methodologies that the owner or operator may use to conduct the performance tests. For each test run: a. Measure the NO_X concentration (in parts per million (ppm)), using USEPA Method 7E or USEPA Method 20 in appendix A of this part. For units complying with the output based standard, concurrently measure the stack gas flow rate, using USEPA Methods 1 and 2 in appendix A of this part, and measure and record the electrical and thermal output from the unit. Then, use the following equation to calculate the NO_X emission rate:	During initial performance test	40 CFR §60.4400(a)(1)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			$E = \frac{1.194 \times 10^{-7} * (NO_X)_c * Q_{std}}{P}$ (Eq. 5) Where: E = NO_X emission rate, in lb/MWh 1.194×10^{-7} = conversion constant, in lb/dscf-ppm $(NO_X)_c$ = average NO_X concentration for the run, in ppm Q_{std} = stack gas volumetric flow rate, in dscf/hr P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to §60.4350(f)(2); or b. Measure the NO_X and diluent gas concentrations, using either USEPA Methods 7E and 3A, or USEPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use USEPA Method 19 in appendix A of this part to calculate the NO_X emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in §60.4350(f) to calculate the NO_X emission rate in lb/MWh.		
6.	EU19	NOx	Sampling traverse points for NOx and (if applicable) diluent gas are to be selected following USEPA Method 20 or USEPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that	During initial performance test	40 CFR § 60.4400(a)(2)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.		
7.	EU19	NOx	Notwithstanding the preceding condition in this table (40 CFR § 60.4400(a)(2)), the owner or operator may test at fewer points than are specified in USEPA Method 1 or USEPA Method 20 in appendix A of this part if the following conditions are met: a. The owner or operator may perform a stratification test for NO_X and diluent pursuant to the procedures specified in section 6.5.6.1(a) through (e) of appendix A of 40 CFR Part 75. b. Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test: i. If each of the individual traverse point NO_X concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent CO_2 (or O_2) from the mean for all traverse points, then the owner or operator may use three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The three points must be located along the measurement line that exhibited the highest average NO_X concentration during the stratification test; or ii. For turbines with a NO_X standard greater than 15 ppm @ 15% O_2, the owner or operator may sample at a single point, located at least 1 meter from the stack wall or at the stack	During initial performance test	40 CFR § 60.4400(a)(3)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			centroid if each of the individual traverse point NO_X concentrations is within ±5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±3ppm or ±0.3 percent CO_2 (or O_2) from the mean for all traverse points; or iii. For turbines with a NO_X standard less than or equal to 15 ppm @ 15% O_2, the owner or operator may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point NO_X concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent CO_2 (or O_2) from the mean for all traverse points.		
8.	EU19	NOx	The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. The owner or operator may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The owner or operator must conduct three separate test runs for the initial performance test. The minimum time per run is 20 minutes. a. If the stationary combustion turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. b. For a combined cycle and CHP turbine systems with supplemental heat (duct burner), the owner or operator must measure the total NO_X emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test. c. If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner	During initial performance test	40 CFR § 60.4400(b)

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			or operator chooses to monitor the steam or water to fuel ratio in accordance with 40 CFR §60.4335, then that monitoring system must be operated concurrently with each USEPA Method 20 or USEPA Method 7E run and must be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable 40 CFR §60.4320 NO_X emission limit. d. Compliance with the applicable emission limit in 40 CFR §60.4320 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average NO_X emission rate at each tested level meets the applicable emission limit in 40 CFR §60.4320. e. If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR §60.4405) as part of the initial performance test of the affected unit. f. The ambient temperature must be greater than 0°F during the performance test.		
9.	EU19	NOx	If the owner or operator has chosen to monitor combustion parameters or parameters indicative of proper operation of NOx emission controls in accordance with 40 CFR §60.4340, the appropriate parameters must be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in 40 CFR §60.4355.	During initial performance test	40 CFR § 60.4410
10.	EU19	SO_2	The owner or operator must conduct an initial performance test for SO_2, as required in 40 CFR §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that may be used to conduct the performance tests. a. <u>Method 1</u>: If The owner or operator	During initial performance test	40 CFR §60.4415(a) 40 CFR §60.8

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for gaseous fuels. The fuel analyses of this section may be performed either by the owner/operator, a service contractor retained by the owner/operator, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using (for gaseous fuels) ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17). b. Method 2: Measure the SO_2 concentration (in ppm), using USEPA Methods 6, 6C, 8, or 20 in appendix A of this part. In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 19–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see §60.17) can be used instead of USEPA Methods 6 or 20. For units complying with the output based standard, concurrently measure the stack gas flow rate, using USEPA Methods 1 and 2 in appendix A of 40 CFR Part 60, and measure and record the electrical and thermal output from the unit. Then use the following equation to calculate the SO_2 emission rate: $E = \frac{1.664 \times 10^{-7} * (SO_2)_c * Q_{std}}{P}$ (Eq. 6) Where: E = SO_2 emission rate, in lb/MWh 1.664×10^{-7} = conversion constant, in lb/dscf-ppm		

Table 7 – Initial Performance Testing Requirements					
Item No.	**Applicable Emission Unit(s)**	**Pollutant/ Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			$(SO_2)_c$ = average SO_2 concentration for the run, in ppm Q_{std} = stack gas volumetric flow rate, in dscf/hr P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR §60.4350(f)(2); or c. Method 3: Measure the SO_2 and diluent gas concentrations, using either USEPA Methods 6, 6C, or 8 and 3A, or 20 in appendix A of this part. In addition, you may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR §60.17). Concurrently measure the heat input to the unit, using a fuel flowmeter (or flowmeters), and measure the electrical and thermal output of the unit. Use USEPA Method 19 in appendix A of this part to calculate the SO_2 emission rate in lb/MMBtu. Then, use Equations 1 and, if necessary, 2 and 3 in 40 CFR §60.4350(f) to calculate the SO_2 emission rate in lb/MWh.		

C. **Monitoring/Testing Requirements**

The owner or operator is subject to the monitoring and testing requirements as contained in Table 8.

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
1.	EU14 EU15 EU16 EU17 EU18	Sulfur content of gaseous fuel (landfill gas)	For the purpose of determining the sulfur content in grains of sulfur per 100 cubic feet of landfill gas, the owner or operator shall use one of the following test methods or Division approved alternatives: a. ASTM D 1072-90; b. ASTM D 4084-94; c. ASTM D 3246-96; d. ASTM D 5504-01; or e. ASTM D 6228-98.	In accordance with the monitoring schedules specified in items (10) and (11) below of this table	Env-A 806.03(a)
2.	EU14 EU15 EU18 EU19	Opacity	Opacity Measurements: a. The owner or operator shall conduct opacity measurements following the procedures set forth in 40 CFR 60 Appendix A, Method 9, *Visual Determination of the Opacity of Emissions from Stationary Sources.* b. The measurements in (a) above shall be taken over 60 minutes during normal operations of the device.	Upon request by DES or USEPA or as determined necessary by the owner or operator	Env-A 807.02
3.	EU16 EU17	Opacity	Opacity Measurements: a. The owner or operator shall conduct measurements of the amount of time that any visible fugitive emissions occur during an observation period by following 40 CFR 60, Appendix A, Method 22 – *Visual Determination of Fugitive Emissions from Material Sources and Smoke Emissions from Flares*. b. The observation period for (a) above is 2 hours and shall be used according to Method 22	Upon request by DES or USEPA or as determined necessary by the owner or operator	Env-A 807.05
4.	Facility wide	Approval of alternate methods or require-ments	Approval of Alternate Methods or Requirements: For any testing or monitoring procedure that is an alternative to a method or requirement specified by these rules, the following procedure shall apply: a. The owner or operator of a source seeking approval of an alternative shall submit to the director the following information: i. A description of the proposed alternate method or requirement;	Upon request by owner or operator	Env-A 809.01

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			ii. The identity of the compound that is to be tested or controlled or the equipment that is to be maintained by the alternate method or requirement; iii. The identity and description of the source at which the alternate method or requirement will be implemented; and iv. Technical data and information demonstrating that the purpose of the specified method or requirement will be achieved by the alternate method or requirement and that the alternative produces results that are no less precise and accurate than those produced by the specified method or requirement; and b. Within 60 days of receipt of a complete application that meets the requirements of (a) above, the director shall: i. Review the application; ii. Issue a written decision: A. Approving the application if the department determines that the alternate method or requirement: 1. Achieves the purpose of the specified method or requirement; and 2. Produces results that are no less precise and accurate than those produced by the specified method or requirement; or B. Denying the application and specifying the reason(s) for the denial; and iii. Notify the applicant and USEPA of the decision.		
5.	Facility wide	Approval of alternate methods or requirement for federal standards	<u>Alternate Methods for Federal Standards:</u> Alternate test methods for compliance with federal standards, such as those specified in 40 CFR 60, 61, and 63, shall be submitted by the owner or operator of the source to USEPA for approval.	Upon request by owner or operator	Env-A 809.02
6.	PC1/EU18	Thermal Oxidizer Combustion	a. The owner or operator shall monitor and record the temperature in the combustion chamber.	Continuous	Env-A 906

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
		Chamber Tempera-ture	b. If the temperature reading is less than the minimum specified in Table 6, Item 11.a, then inspect the unit and take corrective action to raise the temperature	As noted	
7.	PC1/EU18	Thermal Oxidizer Inspection	Conduct a visual external integrity inspection of the thermal oxidizer. a. The inspection shall include an evaluation of whether all emissions are being vented through the dedicated stack exit. b. The inspection shall be conducted by plant personnel familiar with the operation of the oxidizer and associated equipment.	Annually and as conditions indicate it inspection is warranted	RSA 125-C:6, XI
8.	EU14 EU15 EU19	Electrical Power Generation	Determine electrical power generation by either of the following methods: a. By calculating actual electrical power generation in MW-hr by multiplying the heat input in MMBtu obtained from fuel use records by 0.10 MW-hr/MMBtu; or b. By monitoring electrical power generation in kW-hr using one of the monitors specified in Env-A 3705.01(b)(1).	Continuous	Env-A 3705.01
9.	EU19	NOx	a. The owner or operator must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NOx emission result from the performance test is less than or equal to 75 percent of the NOx emission limit for the turbine (the limit is 96 ppm @15% O_2), the owner or operator may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NOx emission limit for the turbine, the owner or operator must resume annual performance tests. b. As an alternative to (a) above, the owner or operator may install, calibrate, maintain and operate one of the following continuous monitoring systems: i. Continuous emission monitoring as described in 40 CFR §60.4335(b) and 40 CFR §60.4345, or ii. Continuous parameter monitoring as follows:	Continuous	40 CFR § 60.4340

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			A. For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, the owner or operator must define parameters indicative of the unit's NOx formation characteristics, and you must monitor these parameters continuously. B. For any lean premix stationary combustion turbine, the owner or operator must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NOx mode.		
10.	EU19	Sulfur content of turbine fuel	<u>Determining the total sulfur content of the turbine combustion fuel</u> a. The owner or operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in (b) below. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR §60.17), which measure the major sulfur compounds, may be used. b. The owner or operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input. The following source of information must be used to make the required demonstration: i. Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 0.060 lb SO_2/MMBtu heat input. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.	As specified within regulation	40 CFR §60.4360 40 CFR §60.4365 40 CFR

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			c. If the owner or operator elects not to demonstrate sulfur content using the option in (b) above (40 CFR §60.4365), and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.		§60.4370
11.	EU19	Sulfur content of turbine fuel	<u>Custom schedules for determination of the total sulfur content of gaseous fuels</u> a. Notwithstanding the requirement of item (10)(c) above of this table, the owner or operator may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (b)(i) and (b)(ii) below of this permit condition, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in 40 CFR §60.4330. b. The two custom sulfur monitoring schedules set forth in paragraphs (i) through (iv) and in paragraph (c) below are acceptable without prior Administrative approval: i. The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (b)(ii), (iii), or (iv) below, as applicable. ii. If none of the 30 daily measurements of the fuel's total sulfur content exceeds half the applicable standard, subsequent sulfur content monitoring may be performed at 12-month intervals. If any of the samples taken at 12-month intervals has a total sulfur content greater than half but less than the applicable limit, follow the procedures	As specified within regulation	40 CFR §60.4370

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			in paragraph (b)(iii) below. If any measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. iii. If at least one of the 30 daily measurements of the fuel's total sulfur content is greater than half but less than the applicable limit, but none exceeds the applicable limit, then: A. Collect and analyze a sample every 30 days for 3 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. Otherwise, follow the procedures in paragraph (b)(iii)(B) below. B. Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. Otherwise, follow the procedures in paragraph (b)(iii)(C) below. C. Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds the applicable limit, follow the procedures in paragraph (b)(iv) below. Otherwise, continue to monitor at this frequency. iv. If a sulfur content measurement exceeds the applicable limit, immediately begin daily monitoring according to paragraph (b)(i) above. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than the applicable limit, are obtained. At that point, the applicable procedures of paragraph (b)(ii) or (iii) above shall be followed. c. The owner or operator may use the data collected from the 720-hour sulfur sampling		

Table 8 – Monitoring and Testing Requirements					
Item No.	**Applicable Emission Unit**	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Regulatory Cite**
			demonstration described in section 2.3.6 of Appendix D to 40 CFR Part 75 to determine a custom sulfur sampling schedule, as follows: i. If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf, no additional monitoring of the sulfur content of the gas is required, for the purposes of 40 CFR Part 60 compliance. ii. If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds half the applicable limit, then the minimum required sampling frequency shall be one sample at 12 month intervals. iii. If any sample result exceeds half the applicable limit, but none exceeds the applicable limit, follow the provisions of paragraph (b)(iii) above. iv. If the sulfur content of any of the 720 hourly samples exceeds the applicable limit, follow the provisions of paragraph (b)(iv) above.		

D. **Recordkeeping Requirements**

The owner or operator is subject to the Recordkeeping requirements as contained in Table 9 below:

Table 9 – Applicable Recordkeeping Requirements

Item No.	Recordkeeping Requirement	Frequency of Recordkeeping	Applicable Emission Unit	Regulatory Cite
1.	Record Retention and Availability: The owner or operator shall keep all records required by this permit on file for a minimum of 5 years.	Keep all records for a minimum of 5 years	Facility Wide	Env-A 902.01(a)
2.	Regulated Toxic Air Pollutant Records: The owner or operator shall maintain records in accordance with the applicable method used to demonstrate compliance pursuant to Env-A 1406.	Maintain at facility at all times	All devices subject to RSA 125-I and Env-A 1400	Env-A 902.01(c)
3.	Subject to Env-A 103, all data submitted to the division, including emission data and applicable emission limitations, shall be available to the public.	As specified in this permit	Facility Wide	Env-A 902.01(d)
4.	General Recordkeeping Requirements for Combustion Devices: The owner or operator of a combustion device shall maintain monthly records of fuel characteristics and utilization, including primary, secondary, tertiary and auxiliary fuels in accordance with the following: a. Fuel consumption; b. Sulfur content as percent sulfur by weight of fuel or in grains per 100 cubic feet of fuel; and c. BTU content per cubic foot of fuel. d. Sources operating one or more combustion devices shall record the hours of operation of each combustion device so that the distribution of fuel among each combustion device can be estimated. e. Items (a) through (d) above must be kept on a daily basis for each day the duct burner (EU08) is operated.	Monthly unless otherwise specified	EU07 EU08 EU14 EU15 EU16 EU17 EU18 EU19	Env-A 903.03
5.	General Recordkeeping Requirements for NOx-emitting Generation Sources: Maintain the following records: a. Actual NOx emissions in accordance with the methods set forth in Env-A 616; b. Fuel usage; c. Hours of operation; d. Power generation as monitored pursuant to Table 8, item 8 of this permit; e. Hours of downtime of the power generation monitoring system, if applicable, during the time period when the generating unit is in operation; and f. Frequency and results of calibrations performed on the power generation monitoring system, as applicable.	Monthly	EU14 EU15 EU19	Env-A 903.06 Env-A 3706.01(b)

Table 9 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
6.	General VOC Recordkeeping Requirements: The owner or operator shall record and maintain the following information at the facility: a. Identification of each VOC-emitting process or device, except processes or devices associated exclusively with non-core activities, as defined in Env-A 1204.03(bp); b. The operating schedule during the high ozone season for each VOC-emitting process or device identified in (a), above, including: i. Hours of operation per calendar month; and ii. Days of operation per calendar month; c. The following VOC emission data: i. Actual VOC emissions from each VOC-emitting process or device identified in (a), above for: A. Each calendar year, in tons; and B. A high ozone season day during that calendar year, in pounds per day; and ii. The emission factors and the origin of the emission factors used to calculate the VOC emissions.	Annually and as applicable	Facility Wide	Env-A 904.02
7.	General NOx Recordkeeping Requirements: The owner or operator shall record and maintain the following information: a. Identification of each combustion device; b. Operating schedule during the high ozone season for each combustion device identified in (a), above, including for each device: i. The typical hours of operation per day; ii. The typical days of operation per calendar month; iii. Number of weeks of operation; iv. Type and amount of each fuel burned; v. Heat input rate in million BTUs per hour or, for incinerators, in tons per hour; and vi. The following NO_x emission data: A. Actual calendar year NOx emissions; B. The typical high ozone season day NOx emissions, in pounds per day; and C. The emission factors and the origin of the emission factors used to calculate the NOx emissions.	Annually and as applicable	Facility Wide	Env-A 905.02

Table 9 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
8.	Additional Recordkeeping Requirements: The Owner or Operator shall maintain a 12-month running total record of emissions of NOx, SO2, CO, TSP, PM10, and VOC for the purpose of demonstrating that emissions of these pollutants are below the facility wide caps in Table 5 of this permit.	Monthly calculation of 12-month rolling average	EU07 EU08 EU14 EU15 EU16 EU17 EU18 EU19	Env-A 906
9.	Thermal Oxidizer Records: The owner or operator shall maintain records of all air pollution control equipment activities required in items 6 and 7 of Table 8, including: a. The monthly hours of operation; b. Records of thermal oxidizer combustion temperature monitoring; c. A log of repairs made to the thermal oxidizer. The log shall include the following: i. The date a problem was observed; ii. The date of the repair; iii. A description of the problem; and iv. The corrective actions taken.	As specified in items 6 and 7 of Table 8 of this permit	PC1/EU18	Env-A 906
10.	NSPS Startup, Shutdown, Malfunction Records: The owner or operator shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; any malfunction of the air pollution control equipment; or any periods during which a CEMS or monitoring device is inoperative.	For each startup, shutdown, malfunction or period where CEMS or monitoring device is inoperative	EU07 EU08 EU19	40 CFR 60.7 (b)
11.	Retention of NSPS Records: a. The owner or operator shall maintain all measurements, including continuous monitoring systems, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR 60 Subpart KKKK recorded in a permanent form suitable for inspection. b. The file in (a) above shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows: i. This paragraph applies to owners or operators required to install a continuous emissions monitoring system (CEMS) where the CEMS	All NSPS records to be maintained for 2 years unless otherwise specified	EU07 EU08 EU19	40 CFR 60.7 (f)

Table 9 – Applicable Recordkeeping Requirements				
Item No.	**Recordkeeping Requirement**	**Frequency of Recordkeeping**	**Applicable Emission Unit**	**Regulatory Cite**
	installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required under item (a) above, the owner or operator shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. ii. This paragraph applies to owners or operators required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under (a) above, the owner or operator shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. iii. The Administrator or DES, upon notification to the source, may require the owner or operator to maintain all measurements as required by (a) above, if the Administrator or DES determines these records are required to more accurately assess the compliance status of the affected source.			

E. **Reporting Requirements**

The owner or operator is subject to the federally enforceable reporting requirements identified in Table 10.

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
1.	General Reporting Requirements: a. The owner or operator of any stationary source, area source or device subject to Env-A 600 shall submit an annual emissions report. b. The annual emissions report pursuant to (a) above, shall include the following information: i. The actual emissions of the stationary source, area source or device and the methods used in calculating such emissions in accordance with Env-A 705.02; ii. For process operations, all information in accordance with Env-A 903.02; iii. For combustion devices, all information in accordance with Env-A 903.03; and iv. The actual annual emissions speciated by individual regulated air pollutants, including a breakdown of VOC emissions by compound. c. The annual emissions report pursuant to (a) above, shall be submitted to the division on or before April 15 of the following year. For example, for calendar year 2008, the annual emissions report shall be submitted to the division on or before April 15, 2009.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 907.01
2.	Reporting Requirements for Sources Subject to the Acid Deposition Control Program. The owner or operator shall submit an annual report by April 15 of the following year containing the following information required pursuant to Env-A 903.03: a. Fuel consumption; b. Sulfur content as percent sulfur by weight of fuel or in grains per 100 cubic feet of fuel; and c. BTU content per cubic foot of fuel.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 907.02
3.	General Reporting Requirements for NOx-emitting Generation Sources. As provided in Env-A 3701.02, the owner or operator of a NOx-emitting generation source, as that term is defined in Env-A 3702, shall report annually by April 15 of the following calendar year, the data required pursuant to Env-A 903.06.	Annually (no later than April 15th of the following year)	EU14 EU15 EU19	Env-A 907.03
4.	VOC Emission Statements Reporting Requirements: a. If the actual facility-wide annual VOC emissions are greater than or equal to 10 tons, the owner or	Annually (no later than April 15th of the	Facility Wide	Env-A 908.02

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	operator shall submit all information pursuant to Env-A 908.03 as applicable, by April 15 of the following calendar year. b. For sources subject to (a) above, updated information specified in items 5 and 6 below of this table shall be submitted to the division for each subsequent calendar year in which actual emissions equal or exceed 10 tons.	following year)		
5.	The owner or operator shall submit the following information to DES in accordance with the schedule set-forth in item 4 of this table, above: a. Facility information, including: i. Source name; ii. Standard Industrial Classification (SIC) code; iii. Physical address; and iv. Mailing address; b. Identification of each VOC-emitting process or device operating at the source identified in (a), above; c. Operating schedule during the high ozone season for each VOC-emitting process or device identified in (b), above, including: i. Hours of operation per calendar day; and ii. Days of operation per calendar week; d. Total quantities of actual VOC emissions for the entire facility and for each process or device identified in (b), above, including: i. Annual VOC emissions, in tons; and ii. Typical high ozone season day VOC emissions, in pounds per day.	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 908.03(a)
6.	The owner or operator shall submit the following information to DES in accordance with the schedule set-forth in item 4 above of this table: a. Identification of each VOC-emitting process or device, except processes or devices associated exclusively with non-core activities, as defined in Env-A 1204.03(bp); b. The operating schedule during the high ozone season for each VOC-emitting process or device identified in (a), above, including: i. Hours of operation per calendar month; and ii. Days of operation per calendar month; c. The following VOC emission data: i. Actual VOC emissions from each VOC-emitting process or device identified in (a),	Annually (no later than April 15th of the following year)	Facility Wide	Env-A 908.03(f)

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	above for: A. Each calendar year, in tons; and B. A high ozone season day during that calendar year, in pounds per day; and ii. The emission factors and the origin of the emission factors used to calculate the VOC emissions.			
7.	NOx Reporting Requirements: The owner or operator shall submit reports of the NOx records kept pursuant to Table 9, Item 7 of this permit (this is the same information specified in Env-A 905.02).	Annually (no later than April 15th of the following year)	EU07 EU08 EU14 EU15 EU16 EU17 EU18 EU19	Env-A 909.02 Env-A 909.03
8.	Prompt Reporting of Permit Deviations: The owner or operator shall promptly report deviations from permit requirements by phone, fax or e-mail in accordance with Section XIX of this permit.	Within 24 hours of discovery of occurrence	Facility Wide	Env-A 911
9.	The owner or operator shall furnish the USEPA Administrator written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows: a. A notification of the date construction (or reconstruction as defined under 40 CFR §60.15) of an affected facility is commenced postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities which are purchased in completed form. b. A notification of the actual date of initial startup of an affected facility postmarked within 15 days after such date. c. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR §60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice. d. A notification of the date upon which demonstration	As specified within regulation	EU19	40 CFR §60.7(a)

Table 10: Applicable Reporting Requirements				
Item No.	**Reporting Requirement**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	of the continuous monitoring system performance commences in accordance with 40 CFR §60.13(c). Notification shall be postmarked not less than 30 days prior to such date. e. The address for USEPA Region 1 is: USEPA Region 1 Attn: Air Compliance Clerk 1 Congress Street Suite 1100 Mail Code SEA Boston, MA 02114-2023			

General Temporary Permit and PSD Permit Conditions

IX. Temporary Permit Renewal Procedures

Pursuant to Env-A 607.02(b), for the reissuance of a temporary permit, an application shall be considered timely if it is received by the department at least 90 days prior to the designated expiration date of the temporary permit.

X. Application Shield

A. Pursuant to Env-A 607.10(a), if an applicant submits a timely application that has been deemed complete by the department for the reissuance of a temporary permit or the issuance of an initial state permit to operate, the failure to have a current and valid temporary permit shall not be considered a violation of RSA 125-C:11,I or Env-A 607.01 unless and until the department takes final action on the application by denying the requested reissuance of a temporary permit or issuance of a state permit to operate.

B. Pursuant to Env-A 607.10(b), if the department deems an application complete, but requests additional information pursuant to Env-A 607.06(b), the protection granted in Env-A 607.10(a) shall cease to apply when the applicant fails to submit in writing such additional requested information by the deadline specified in the request.

XI. Permit Shield

Pursuant to Env-A 607.08(c), the expiration of a temporary permit shall terminate the owner or operator's right to construct or operate a new or modified source or device pursuant to the permit, unless a timely and complete application for a state permit to operate, title V operating permit, or an amendment thereto, has been received by the department. Upon the submittal of a timely and complete application for any of the foregoing permits, the right to construct shall continue, under the terms and conditions of the expired temporary permit, pending the department's decision on the application.

XII. Administrative Permit Amendments

A. An administrative permit amendment includes the following:

1. Corrects typographical errors;
2. Requires more frequent monitoring or reporting; or
3. Allows for a change in ownership or operational control of a source provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Division.

B. The owner or operator may implement the changes addressed in the request for an administrative amendment immediately upon submittal of the request.

XIII. Minor Permit Amendments

A. The owner or operator shall submit to the Division a request for a minor permit amendment for any proposed change to any of the conditions contained in this permit which will not result in an increase in the amount of a specific air pollutant currently emitted by the devices listed in Condition VI.A and will not result in the emission of any air pollutant not emitted by the source or device.

B. The request for a minor permit amendment shall be in the form of a letter to the Division and shall include the following:
   1. A description of the proposed change; and
   2. A description of any new applicable requirements that will apply if the change occurs.

C. The Owner or Operator may implement the proposed change immediately upon filling a request for the minor permit amendment.

XIV. Significant Permit Amendments

A. The Owner or Operator shall submit a written request for a permit amendment to the Division at least 90 days prior to the implementation of any proposed change to the physical structure or operation of the devices covered by this permit which increases the amount of a specific air pollutant currently emitted by such device or which results in the emission of any regulated air pollutant currently not emitted by such device.

B. A request for a significant permit amendment shall include the following:
   1. A complete application form, as described in Env-A 1703 through Env-A 1708, as applicable;
   2. A description of:
      a. The proposed change;
      b. The emissions resulting from the change;
      c. Any new applicable requirements that will apply if the change occurs; and
      d. Where air pollution dispersion modeling is required for a device pursuant to Env-A 606.02, the information required pursuant to Env-A 606.03.

C. The owner or operator shall not implement the proposed change until the Division issues the amended permit.

XV. Temporary Permit/PSD Permit Suspension, Revocation or Nullification

A. Pursuant to RSA 125-C:13, the Director may suspend or revoke any final permit issued hereunder if, following a hearing, the Director determines that:

   1. The owner or operator has committed a violation of any applicable statute or state requirement found in the New Hampshire Rules Governing the Control of Air Pollution, order or permit condition in force and applicable to it; or

   2. The emissions from any device to which this permit applies, alone or in conjunction with other sources of the same pollutants, presents an immediate danger to the public health.

B. The Director shall nullify any permit, if following a hearing in accordance with RSA 541-A:30, II, a finding is made that the permit was issued in whole or in part based upon any information proven to be intentionally false or misleading.

XVI. Inspection and Entry

USEPA and DES personnel shall be granted access to the facility covered by this permit, in accordance with RSA 125-C:6,VII, for the purposes of: inspecting the proposed or permitted site; investigating a complaint; and assuring compliance with any applicable requirement or state requirement found in the NH Rules Governing the Control of Air Pollution and/or conditions of any permit issued pursuant to Chapter Env-A 600.

XVII. Reports

All reports submitted to DES (except those submitted as emission based fees as outlined in Section XVIII of this Permit) shall be submitted to the following address:

New Hampshire Department of Environmental Services
Air Resources Division
29 Hazen Drive, P.O. Box 95
Concord, NH 03302-0095
ATTN: Section Supervisor, Compliance Bureau

All reports submitted to USEPA shall be submitted to the following address:

US EPA, Region I
Attn: Compliance Clerk (mailcode: SEA)
One Congress St., Suite 1100
Boston, MA 02114

XVIII. Emission-Based Fee Requirements

A. Env-A 705.01, *Emission-based Fees*: The Owner or Operator shall pay to the Division each year an emission-based fee for emissions from the devices listed in Condition VI.A of this permit.

B. Env-A 705.02, *Determination of Actual Emissions for use in Calculating of Emission-based Fees*: The Owner or Operator shall determine the total actual annual emissions from the devices listed in Condition VI.A for each calendar year in accordance with the methods specified in Env-A 616, Determination of Actual Emissions. If the emissions are determined to be less than one ton, the emission-based fee shall be calculated using an emission-based multiplier of one ton.

C. Env-A 705.03, *Calculation of Emission-based Fees*: The Owner or Operator shall calculate the annual emission-based fee for each calendar year in accordance with the procedures specified in Env-A 705.03 and the following equation:

$$FEE = E * DPT$$

where:

FEE = The annual emission-based fee for each calendar year as specified in Env-A 705;
E = Total actual emissions as determined pursuant to Condition XVIII.B; and
DPT = The dollar per ton fee the Division has specified in Env-A 705.03(e).

D. Env-A 3704.01, *Calculation of NOx Emissions for One or More NOx Emitting Generation Sources Located at a Single Stationary Source*: The Owner or Operator shall calculate average monthly emissions from the generators using the following equation:

$$E_{total} = \left(A_{generator\,285} + A_{generator\,270}\right) - \frac{7 * \left(B_{generator\,285} + B_{generator\,270}\right)}{2000}$$

where:

E_{total} = The total NOx emissions in tons per month;
A = The actual NOx emissions in tons per month for each generator; and
B = The actual power generation for each generator in megawatt-hours of electricity produced per month.

E. Env-A 3704.02, *Calculation of NO_x Emissions for Replacement Sources With Increased Generation Capacity*: The Owner or Operator shall calculate the total NOx emissions attributable to the increase in the amount of generating capacity using the following equation:

$$E = \frac{\left(MW_{new} - MW_{old}\right)}{MW_{old}} * E_{total}$$

where:

E = The total NO_x emissions subject to fees in tons per month;
E_{total} = The total NO_x emissions as calculated in Condition XI.D;
MW_{new}= The total generation capacity from EU02 and EU03 after the replacement; and
MW_{old}= The total generation capacity from EU02 and EU03 before the replacement.

F. Env-A 3707.03, *Calculation of NO_x Emissions Reduction Fund Fees*: The NO_x emissions reduction fund fee shall be equal to the total tons of NO_x emissions calculated in accordance with Condition XVIII.D multiplied by the NO_x emissions reduction fund fee in dollars per ton as listed in Table 11:

Table 11 - NO_x Emissions Reduction Fund Fee

Time Period	NO_x Emissions Reduction Fund Fee (Dollars Per Ton)
January 1 to April 30	500
May 1 to September 30	1000
October 1 to December 31	500

G. Env-A 705.04, *Payment of Emission-based Fee*: The Owner or Operator shall submit, to the Division, payment of the emission-based fee and the NO_x emissions reduction fund fee by April 15th for emissions during the previous calendar year. For example, the fees for calendar year 2007 shall be submitted on or before April 15, 2008.

XIX. Permit Deviation

A. In the event of a permit deviation, The owner or operator shall:

1. Investigate and take corrective action immediately upon discovery of the permit deviation to restore the affected device, process, or air pollution control equipment to within allowable permit levels; and

2. Record the following information:

   a. The permit deviation;
   b. The probable cause of the permit deviation;
   c. The date of the occurrence;
   d. The duration;
   e. The specific device that contributed to the permit deviation; and
   f. Any corrective or preventative measures taken.

3. If the permit deviation does not cause excess emissions, but continues for a period greater than 9 consecutive days, the source shall notify the division by telephone or fax on the tenth day of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday, of the subsequent corrective actions to be taken.

4. In the event of a permit deviation that causes excess emissions, The owner or operator of the affected device, process, or air pollution control equipment shall:

   a. Notify the division of the permit deviation and excess emissions by telephone or fax, within twenty-four (24) hours of discovery of the permit deviation, unless it is a Saturday, Sunday, or state or federal legal holiday, in which event, the division shall be notified on the next day which is not a Saturday, Sunday, or state or federal legal holiday; and

   b. Submit a written report, in accordance with (A)(6) below, to the division within ten (10) days of discovery of the permit deviation reported in (A)(4)(a), above.

5. In the event of a permit deviation caused by a failure to comply with the data availability requirements of Env-A 800, The owner or operator of the source shall:

   a. Notify the division of the permit deviation by telephone or fax, within 10 days of discovery of the permit deviation; and

   b. Report the permit deviation to the division, as part of the excess emissions report submitted in accordance with Env-A 800.

6. The written report, pursuant to (A)(4)(b) above, shall include the following information:

   a. Facility name;
   b. Facility address;
   c. Name of the responsible official employed at the facility;
   d. Facility telephone number;

e. Date(s) of the occurrence;
f. Time of the occurrence;
g. Description of the permit deviation;
h. The probable cause of the permit deviation;
i. Corrective action taken to date;
j. Preventative measures taken to prevent future occurrences; and
k. Date and time that the device, process, or air pollution control equipment returned to operation in compliance with an enforceable emission limitation, or operating condition;
l. The specific device, process or air pollution control equipment that contributed to the permit deviation;
m. The type and quantity of excess emissions emitted to the atmosphere due to the permit deviation; and
n. The calculation or estimation used to quantify the excess emissions.

B. In accordance with 40 CFR Part 70.6(a)(3)(iii)(A), sources subject to Env-A 609 that have been issued a title V permit, shall report to the division, at a reporting frequency no less stringent than semi-annually, the following information:

1. A summary of all permit deviations previously reported to the division pursuant to Env-A 911.04(a) and (b), for the reporting period;

2. A list of all permit deviations recorded pursuant to Env-A 911.03(b).

C. Sources subject to Env-A 607, Env-A 608, or Env-A 609 that have not been issued a title V permit, but have been issued a state permit to operate or a temporary permit, shall report to the division, at least annually by April 15, all information pursuant to (B) above.

XX. Emission Reduction Credits (ERC) Trading Program (Env-A 3000)

In accordance with Env-A 3000, *Emissions Reduction Credits Trading Program* and the *Certificates of Emissions Reduction Credits Generation*, ERC Certificates 97NUNH02C and 04NHCHEM01C, UNH shall be allowed to use a total of 57 ERCs to offset NOx emissions for the purpose of complying with the requirements of New Source Review (Env-A 618). Of the total 57 ERCs, 24 ERCs are certified as ozone season ERCs and 33 are certified as non-ozone season ERCs.

XXI. Emissions Offset Requirements (Env-A 618.04)

Prior to commencing operation for this project, UNH shall demonstrate that NOx offsets have been obtained in a ratio of 1.2 to 1.0. Such emission offsets shall be real, surplus, quantifiable, permanent and federally enforceable and shall be certified by DES in accordance with all applicable state and federal regulations, including Env-A 3000.