STATE OF NEW HAMPSHIRE
Department of Environmental Services
Air Resources Division

Temporary Permit
And
Prevention of Significant Deterioration Permit

Source ID No: **3301590793**
Permit No: **TP-B-0526**
County: **Rockingham**
Date Issued: **December 12, 2006**

This certifies that:

Newington Energy, LLC
Newington Power Facility
200 Shattuck Way, Newington, NH

has been granted a Joint Federal Prevention of Significant Deterioration (PSD) Permit and a State of New Hampshire Temporary Permit **for a 595 MW Combustion Turbine Facility.**

New Hampshire has EPA-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/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 **January 30, 2004** in accordance with RSA 125-C of the New Hampshire Laws. The PSD 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 Permit that modifies the terms and conditions of this permit. The Temporary provisions of this permit are valid until **June 30, 2008**. Request for Temporary Permit provision renewal prior to the expiration of the Temporary provisions of this permit is subject to Division requirements and must be accompanied by the appropriate permit application forms.

This permit is valid provided the devices are operated in accordance with all the legally enforceable conditions specified within this permit:

The Owner or Operator of the devices as specified by this permit shall be subject to all applicable State and Federal air pollution control regulations, including (but not limited to):

A. The New Hampshire Code of Administrative Rules Env-A 100 et seq., ***New Hampshire Rules Governing the Control of Air Pollution***;
B. The Code of Federal Regulations (CFR), 40 CFR Part 60, Subparts Db and Dc, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units;*
C. The Code of Federal Regulations (CFR), 40 CFR Part 60, Subpart GG, *Standards of Performance for Stationary Gas Turbines*; and
D. The Code of Federal Regulations (CFR), 40 CFR Part 75, *Continuous Emissions Monitoring.*

All equipment, facilities and systems installed and used to achieve compliance with the terms and conditions of this permit shall at all times be maintained in good working order and be operated as efficiently as possible to minimize air pollutant emissions.

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 (that would require a modification to this permit) 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 devices or which results in the emission of any regulated air pollutant currently not emitted by such devices. The change shall not take place until a new permit application is submitted and acted upon by the Director pursuant to Env-A 600.

This permit (or a copy) should be appropriately displayed near the device for which it is issued.

COPY

Director, Air Resources Division

ABBREVIATIONS

AP-42	Compilation of Air Pollutant Emission Factors
ARD	Air Resources Division
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
Btu	British Thermal Units
CAA	Clean Air Act
CEMS	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
HAP	Hazardous Air Pollutant
HHV	Higher Heat Value
hr	Hour
lb	Pound
lb/hr	Pounds per hour
LHV	Lower Heat Value
MMBtu	Million British Thermal Units
NAAQS	National Ambient Air Quality Standard
NH_3	Ammonia
NHDES (or DES)	New Hampshire Department of Environmental Services
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standard
NSR	New Source Review
PM_{10}	Particulate Matter less than 10 microns diameter
ppm	part per million
ppmdv	part per million by dry volume
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
RTAP	Regulated Toxic Air Pollutant
scf	Standard cubic feet
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TSP	Total Suspended Particulate Matter
TPY	Tons per Year
USEPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound

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I. Facility Description of Operations

Newington Energy, LLC ("NEL") currently operates a nominal 518 Megawatt ("MW") (at 95° F) (gross electrical output) combined cycle combustion turbine facility in Newington, NH. The NEL facility consists of two combustion turbines with two heat recovery steam generators ("HRSGs") and a single steam turbine, one natural gas-fired auxiliary boiler, six natural gas-fired fuel gas heaters, one diesel-fired emergency generator, and one diesel-fired emergency firewater pump. The NEL facility is classified as a "combined cycle" plant, as it produces electrical power with two gas turbines and a steam turbine. Each combustion turbine is rated at approximately 154 MW (at 95°F). The exhaust gas from each turbine passes through separate HRSGs connected to a single steam turbine producing approximately an additional 224 MW. At lower ambient temperatures (0°F) the turbine output ratings would increase to approximately 195 MW each, producing a plant capacity of 595 MW (195 + 195 + 205).

During limited summer hours, the NEL facility will operate in a supplemental firing mode to boost power output. During the supplemental firing mode, duct burners are fired to increase the exhaust heat to the HRSGs. Auxiliary equipment at the NEL facility includes a wet mechanical draft cooling tower and a water treatment system**.** Air pollution control at the facility includes a NOx reduction system, a combustion control system to minimize CO, and monitors to continuously record CO, NOx, opacity and certain operational parameters.

NEL received Prevention of Significant Deterioration (PSD) permit # PSD 044-121NH10 from the United States Environmental Protection Agency (USEPA) and a Temporary Permit FP-T-0036 on April 26, 1999.

II. Project Description

The purpose of this permit is to incorporate permit modifications requested by NEL as well as modifications required by DES in the original PSD/Temporary Permit. NEL has requested an increase in the amount of fuel oil that can be combusted in Combustion Turbines #1 and #2, from 19,850,000 gallons to 33,120,000 gallons during any 12-consecutive month period. NEL has also requested a less frequent reporting period for ammonia usage at this facility, specifically, reducing the reporting frequency from a monthly to a quarterly basis.

This permit incorporates additional permit conditions related to the periods of startup, shutdown, and fuel transition at this facility. In the original PSD/Temporary Permit, NEL was required to propose (and DES to establish) permit limits for periods of startup, shutdown, and fuel transition. The PSD/Temporary Permit also required NEL to propose (and DES to establish) operational and emissions limitations during periods of startup and shutdown. DES has evaluated the proposed limits and incorporated these limits into this permit.

In addition to the above modifications, this permit streamlines and replaces two existing permits: the original PSD/Temporary Permit (DES Temporary Permit FP-T-0036, EPA PSD Permit 044-121NH10), and Temporary Permit TP-B-0483, which was originally issued for one natural gas-fired Auxiliary Boiler, eight natural gas-fired Fuel Gas Heaters, a diesel-fired Emergency Generator, and a diesel-fired Firewater Pump. This permit also incorporates the replacement of the eight original natural gas-fired Fuel Gas Heaters with six new natural gas-fired Fuel Gas Heaters.

Pollutant emissions will increase as a result of the increase in fuel oil firing in Combustion Turbines #1 and #2, while pollutant emissions will decrease as a result of the replacement of the eight natural gas-fired Fuel Gas Heaters with six new natural gas-fired Fuel Gas Heaters. DES evaluated all of the facility-wide emissions increases and decreases and determined that the modifications do not trigger the thresholds for significant modifications under the PSD and non-attainment New Source Review programs. Table 1 below summarizes the net emissions increases/decreases resulting from the increase in fuel oil firing in Combustion Turbines #1 and #2 and the replacement of the existing fuel gas heaters.

Table 1: Prevention of Significant Deterioration (PSD) and Non-Attainment Applicability Thresholds (All Values in Tons Per Year)

	Pollutant					
	Nitrogen Oxides (NOx)	**Carbon Monoxide (CO)**	**Total Particulate Matter (PM) Particulate Matter Less than 10 Microns (PM-10)**	**Volatile Organic Compounds (VOC)**	**Sulfur Dioxide (SO_2)**	**Sulfuric Acid Mist (H_2SO_4)**
(1) Baseline Annual Emission Rate from All Devices Contained in Temporary Permit FP-T-0036/ EPA PSD Permit 044-121NH10[1]	204.9	484.8	104.8	36.3	125.4	20.9
(2) Baseline Annual Emission Rate from All Devices Contained in Temporary Permit TP-B-0483	6.2	4.8	0.7	0.6	1.1	0.0
Baseline Annual Emission Rate from All Devices Combined (sum of (1) and (2) above)	211.1	489.6	105.5	36.9	126.5	20.9
(3) Emissions Increase/(Decrease) due to Increase in Fuel Oil Firing for Combustion Turbines #1 and #2	18.9	41.9	2.4	2.2	(-70.2)	6.7
(4) Emissions Increase/(Decrease) due to Replacement of Eight Existing Fuel Gas Heaters with Six New Fuel Gas Heaters	(-0.5)	(-1.8)	(-0.1)	(-0.1)	0.1[2]	(-0.0)
(5) Total Emissions Increases/(Decreases) due to Above Modifications (sum of (3) and (4) above)	18.4	40.1	2.3	2.1	(-70.1)	6.7
PSD/Nonattainment Modification Significance Threshold (Compare to (5) above)	40 (PSD) 25 (NA)	100	25/15	25	40	7
PSD/ Non-Attainment Significance Threshold Levels Exceeded (Y/N)	N	N	N	N	N	N

Notwithstanding the above determination, since the facility has requested an increase in the amount of fuel oil

[1] Pursuant to 40 CFR 52.21(b)(21)(iii) and 40 CFR 165.(a)(1)(xii)(C), the reviewing authority may presume that the source-specific allowable emissions (i.e., permitted emission limits) for the unit are equivalent to the actual emissions of the unit. For purposes of this permitting review, NHDES agrees with the source that it is appropriate to consider the actual emissions as the source-specific allowable emissions for the unit, rather than the average annual emissions over the two years preceding the project.

[2] While the total heat input of the new fuel gas heaters will decrease, the SO_2 emissions are shown as an increase due to a revision of the USEPA AP-42 (5th Edition) SO_2 emission factor that occurred after the issuance of Temporary Permit TP-B-0483.

firing, and since the fuel oil firing limit was originally established as a part of the BACT limit for SO_2, DES concluded that the facility must revisit the original BACT determinations for SO2, CO, PM, NOx, and sulfuric acid mist. This conclusion is based on discussions with USEPA Region 1, as well as USEPA guidance found in the USEPA NSR Policy and Guidance database. The BACT review is discussed and supported in the Final Determination and the BACT limits are established in Section VI this permit.

III. Significant Activities Identification

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

Table 2 - Permitted Activities

Device	Manufacturer, Model, Installation Date	Operating Limitations
EU01 - Combustion Turbine #1 (designated as CT #1) with Heat Recovery Steam Generator (HRSG)	General Electric Frame 7FA Date installed: June 2002	1. Combustion Turbines #1 and #2 shall each be limited to 1,905 MMBtu/hr (LHV), equivalent to 2,115 MMBtu/hr (HHV) gross heat input while firing natural gas or 2,092 MMBtu/hr (LHV), equivalent to 2,218 MMBtu/hr (HHV) gross heat input while firing low sulfur distillate fuel oil. 2. Supplemental fuel firing in each HRSG for power augmentation purposes shall be limited to 177.7 MMBtu/hr (HHV) gross heat input. Fuel limited to natural gas only.
EU02 - Combustion Turbine #2 (designated as CT #2) with Heat Recovery Steam Generator (HRSG)	General Electric Frame 7FA Date installed: June 2002	
EU03 - Ten Cooling Towers	Marley Wet Mechanical draft Cooling Tower Date installed: 2002	1. Cooling Tower drift shall be limited to 0.0005 % of the circulating water flow rate.
EU04 – Auxiliary Boiler	Hurst Boiler Model No. S2XID-G-600-2001 Date installed: June 2002	1. The maximum gross heat input of the auxiliary boiler shall be limited to 25.2 MMBtu/hr (HHV). 2. Operating hours for the auxiliary boiler shall be limited to 2,000 hours per consecutive 12-month period. 3. The natural gas burned in the auxiliary boiler shall contain no more than 15 grains of sulfur per 100 cubic feet of gas, calculated as hydrogen sulfide at standard temperature and pressure.
EU05 – Six Fuel Gas Heaters	Laars Model No. 2400 Date installed: August 2004	1. The maximum gross heat input of each of the six fuel gas heaters shall be limited to 2.4 MMBtu/hr (HHV). 2. The natural gas burned in the fuel gas heaters shall contain no more than 15 grains of sulfur per 100 cubic feet of gas, calculated as hydrogen sulfide at standard temperature and pressure.
EU06 – Diesel Emergency Generator	Cummins Model No. QSX15-G9 Installed June 2002	1. The maximum gross heat input of the Diesel Emergency Generator shall be limited to 5.2 MMBtu/hr (HHV). 2. Operating hours for the Diesel Emergency Generator shall be limited to 500 hours during any consecutive 12-month period. 3. The diesel fuel (No. 2 oil) combusted in the Diesel Emergency Generator shall not exceed 0.40 percent sulfur by weight.

Table 2 - Permitted Activities		
Device	**Manufacturer, Model, Installation Date**	**Operating Limitations**
EU07 – Diesel Firewater Pump	John Deere Model No. JDFP-06WR Installed June 2002	1. The maximum gross heat input of the Diesel Firewater Pump shall be limited to 1.9 MMBtu/hr (HHV). 2. Operating hours for the Diesel Firewater Pump shall be limited to 500 hours during any consecutive 12-month period. 3. The diesel fuel (No. 2 oil) combusted in the Diesel Firewater Pump shall not exceed 0.40 percent sulfur by weight.

IV. Stack Criteria

The emission units listed in Table 2 above shall each have an unobstructed, vertical discharge to the atmosphere and meet the following criteria:

Table 3 - Stack Criteria		
Emissions Device	**Minimum Stack Height (Feet)**	**Maximum Stack Diameter (Feet)**
Combustion Turbine #1	150	16.75
Combustion Turbine #2	150	16.75
10 Cooling Tower Exhaust Fans	54.5	33.7
Auxiliary Boiler	35	1.75
Six Fuel Gas Heaters	50	4.0

V. Pollution Control Equipment Identification

The devices identified in Table 4 are considered pollution control equipment or techniques for each identified emission unit:

Table 4 - Pollution Control Equipment Identification			
Pollution Control Equipment Number	**Description of Equipment**	**Purpose**	**Emission Unit Number Controlled**
PCE1	1. Dry low-NOx (DLN) in conjunction with Selective catalytic Reduction (SCR) - for natural gas combustion 2. Water injection system in conjunction with SCR - for distillate oil combustion	For NOx Control	EU01
PCE2	1. Dry low-NOx (DLN) in conjunction with SCR - for natural gas combustion 2. Water injection system in conjunction with SCR - for distillate oil combustion	For NOx Control	EU02

Table 4 - Pollution Control Equipment Identification			
Pollution Control Equipment Number	**Description of Equipment**	**Purpose**	**Emission Unit Number Controlled**
PCE3	1. Each of the 10 cooling tower cells (i.e., 5 per each cooling tower) is equipped with a single layer of Marley drift eliminator plus a suspended layer of Marley honeycomb cooling tower fill.	To minimize water drift losses and plume visibility	EU03

VI. Operating Conditions and Emissions Limitations

The owner or operator shall be subject to the operational and emission limitations identified in Table 5 below:

Table 5 - Operational and Emission Limitations			
Item #	**Applicable Requirements**	**Applicable Emission Unit**	**Regulatory Cite**
1.	The emissions of any regulated toxic air pollutant (RTAP) shall not cause an exceedance of its associated 24-hour or annual ambient air limit as set forth in Env-A 1450.01, *Table Containing the List Naming All Regulated Toxic Air Pollutants*.	Facility Wide	Env-A 1400
2.	The owner of any device or process that emits a RTAP, shall determine compliance with the ambient air limits by using one of the methods provided in Env-A 1405.02, Env-A 1405.03, Env-A 1405.04, Env-A 1405.05 or Env-A 1405.06.	Facility Wide	Env-A 1405.01
3.	Documentation for the demonstration of compliance shall be retained at the facility, and shall be made available to the DES for inspection.	Facility Wide	Env-A 1403.01(d)
4.	Combustion Turbines #1 and #2 shall each be limited to 1,905 MMBtu/hr (LHV), equivalent to 2,115 MMBtu/hr (HHV) gross heat input while firing natural gas or 2,092 MMBtu/hr (LHV), equivalent to 2,218 MMBtu/hr (HHV) gross heat input while firing low sulfur distillate fuel oil.	EU01 & EU02	PSD Permit 044-121NH10
5.	The combustion of low sulfur distillate fuel oil in Combustion Turbine #1 and #2 combined shall be limited to 33,120,000 gallons during any 12 consecutive month period.	EU01 & EU02	TP-B-0526
6.	Supplemental fuel firing in each HRSG for power augmentation purposes shall be limited to 177.7 MMBtu/hr (HHV) gross heat input.	EU01 & EU02	PSD Permit 044-121NH10
7.	Combustion of supplemental fuel in the HRSGs shall be limited to the combustion of natural gas.	EU01 & EU02	PSD Permit 044-121NH10
8.	Power augmentation shall be limited to periods when ambient temperatures exceed 60°F or periods when the facility is conducting contract-required performance testing or compliance stack testing. Periods of power augmentation shall not exceed 1,800 hours during any 12 consecutive month period.	EU01 & EU02	PSD Permit 044-121NH10
9.	Combustion Turbines #1 and #2 shall not fire natural gas and fuel oil simultaneously except during periods of transition from one fuel to the other. Such transition periods shall, to the extent practical, be minimized.	EU01 & EU02	PSD Permit 044-121NH10

Table 5 - Operational and Emission Limitations			
Item #	**Applicable Requirements**	**Applicable Emission Unit**	**Regulatory Cite**
10.	The natural gas shall contain no more than 2.5 grains of sulfur per 100 cubic feet of gas at standard temperature and pressure. Monitoring of sulfur content and fuel quality of the natural gas shall be conducted in accordance with the provisions of 40 CFR 60.334 (Subpart GG).	EU01 & EU02	PSD Permit 044-121NH10
11.	Beginning on the issuance date of this permit, Newington Energy shall only receive distillate oil that complies with the transportation grade sulfur limit of 0.0015 percent by weight. Newington Energy is permitted to use the remainder of previously purchased distillate oil with a maximum sulfur content of 0.05 percent by weight (approximately 3 million gallons). Monitoring of sulfur content in the fuel oil shall be conducted in accordance with the provisions of 40 CFR 60.334 (Subpart GG).	EU01 & EU02	PSD Permit 044-121NH10
12.	The natural gas shall contain no more than 15 grains of sulfur per 100 cubic feet of gas at standard temperature and pressure.	EU04 EU05	Env-A 1605.01
13.	The diesel fuel (No. 2 fuel oil) burned in the emergency generator and firewater pump shall not exceed 0.40 percent sulfur by weight.	EU06 EU07	Env-A 1604.01
14.	NEL shall maintain a program of best management practices for the minimization of fugitive particulate matter during any period of construction, reconstruction, or operation which may result in fugitive dust.	EU01 & EU02	PSD Permit 044-121NH10
15.	With the exception of startup and shutdown periods, NEL shall operate the SCR systems at all times to reduce NOx emissions.	EU01 & EU02	PSD Permit 044-121NH10
16.	The Cooling Tower shall be equipped with High Efficiency Drift Eliminators to minimize water drift losses and plume visibility. Drift from the Cooling Tower shall be limited to 0.0005% of the circulating water flow rate.	EU03	PSD Permit 044-121NH10

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Table 5 - Operational and Emission Limitations			
Item #	**Applicable Requirements**	**Applicable Emission Unit**	**Regulatory Cite**
17.	The combustion turbines shall comply with the following emission limitations:	EU01 & EU02	PSD Permit 044-121NH10

Table 6 - Emission Limitations			
Pollutant	**Emission Limitation**	**Control Technology**	**Averaging Time**
Sulfur Dioxide (Gas Firing)	0.0036 lb/MM BTU	Low Sulfur Fuels (BACT)	3 hour rolling
Sulfur Dioxide (Oil Firing)	0.0505 lb/MM BTU[3] 0.0015 lb/MM BTU	Low Sulfur Fuels (BACT)	3 hour rolling
Carbon Monoxide (Gas Firing)	15 ppmdv @ 15 %O_2 at all loads	Low NOx Burner with Good Combustion Practices (BACT)	1 hour block average
Carbon Monoxide (Oil Firing)	20 ppmdv @ 15 %O_2 @75 to 100% load 30 ppmdv @ 15 %O_2 @50 to 74% load	Low NOx Burner with Good Combustion Practices (BACT)	1 hour block average
TSP/PM-10 (Gas Firing)	0.015 lb/MMBtu	Low Sulfur Fuels (BACT)	1 hour block average
TSP/PM-10 (Oil Firing)	0.040 lb/MMBtu	Low Sulfur Fuels (BACT)	1 hour block average
Opacity	20 %	Good Combustion Practices	6 minute block average
Nitrogen Oxides (Gas Firing)	2.5 ppmdv @ 15 % O_2	Low NOx Burner with SCR (LAER/BACT)	3 hour block average
Nitrogen Oxides (Oil Firing)	9.0 ppmdv @ 15 % O_2	Low NOx Burner with Water Injection and SCR (LAER/BACT)	1 hour block average
VOCs (Gas Firing)	0.002 lb/MMBtu	Good Combustion Practices	1 hour block average
VOCs (Oil firing)	0.0038 lb/MMBtu	Good Combustion Practices	1 hour block average
Sulfuric Acid Mist (H_2SO_4) (Gas Firing)	0.00083 lb/MMBtu	Low Sulfur Fuels (BACT)	1 hour block average
Sulfuric Acid Mist (H_2SO_4) (Oil Firing)	0.0116 lb/MMBtu	Low Sulfur Fuels (BACT)	1 hour block average
Opacity	20%	Good Combustion Practices	6 minute block average
Ammonia	10 ppmdv @ 15 % O_2	N/A	24 hour block average

* Emission limits for carbon monoxide and nitrogen oxides apply at all times, except start-up and shutdown.

18.	The emission limits for startup conditions shall apply for fuel transition periods.	EU01 & EU02	PSD Permit 044-121NH10

[3] The SO_2 BACT oil firing limit of 0.0505 lb/MMBTU shall apply until such time that the sulfur content of the distillate fuel oil in the storage tank drops below 0.0015% by weight. At that time, the SO_2 BACT oil firing limit of 0.0015 lb/MMBTU will apply to emission units EU01 and EU02.

Table 5 - Operational and Emission Limitations

Item #	Applicable Requirements	Applicable Emission Unit	Regulatory Cite
19.	Maximum hourly emissions of regulated pollutants from each Combustion Turbine shall be limited as specified in Table 7 below: (see Table 7) The above emission rates are calculated based on heating values of 1,000 Btu/scf for Natural Gas and 140,000 BTU/gallon for low sulfur distillate oil.	EU01 & EU02	PSD Permit 044-121NH10

Table 7 - Maximum Hourly Emission Rates

Pollutant	Maximum Rate lb/hr on Natural Gas @ 100% load and 0° F	Maximum Rate lb/hr on Fuel Oil @ 100% load and 0° F	Averaging Time
NOx	19.48	77.60	3-hour block average
SO_2	6.30	97.60[4] 3.33	3-hour rolling average
CO	71.16	104.98	1-hour block average
TSP/PM-$_{10}$	11.00	20.00	1-hour block average
Sulfuric Acid Mist (H_2SO_4)	0.92	14.2	1-hour block average
VOCs	4.23	8.43	1-hour block average
Ammonia	28.84	31.91	24-hour block average

The above emission rates are calculated based on heating values of 1,000 Btu/scf for Natural Gas and 140,000 BTU/gallon for low sulfur distillate oil.

[4] The SO_2 oil firing limit of 97.6 lb/hr shall apply until such time that the sulfur content of the distillate fuel oil in the storage tank drops below 0.0015% by weight. At that time, the SO_2 oil firing limit of 3.33 lb/hr will apply to emission units EU01 and EU02.

Item #	Applicable Requirements	Applicable Emission Unit	Regulatory Cite
20.	Maximum 12 month rolling emissions of regulated pollutants shall be limited as specified in Table 8 below: (see Table 8 below)	Facility wide	PSD Permit 044-121NH10 & Application #FY04-0157
21.	NEL shall, to the extent practical, minimize emissions from the Combustion Turbines during start-up or shutdown	EU01 & EU02	PSD Permit 044-121NH10

Table 5 - Operational and Emission Limitations

Table 8. Maximum 12 Month Rolling Emissions Limits

Pollutant	Maximum Rate on Natural Gas[a] (for two CTs combined) (tons)	Maximum Rate on Fuel Oil[b] (for two CTs combined) (tons)	Maximum Rate for Two CTs Combined on Both Fuels[c] (tons)	Facility wide Emission Limits (tons)
NOx	151.4	93.1	223.8	229.5
SO_2	55.2	117.1[5] 4.0	164.7[6] 55.2	165.9[7] 56.4
CO	464.3	126.0	526.7	529.7
TSP/PM-10	96.4	24.0	107.2	107.8
Sulfuric Acid Mist (H_2SO_4)	12.3	17.0	27.6	27.6
VOCs	32.9	10.1	38.5	39.0
Ammonia	245.3	38.3	256.4	256.4

a. Assumes that the facility operates up to 8,760 hr/yr on natural gas. Annual emission limits for natural gas combustion are based on hourly emission rates at 100% load and 50°F (average annual ambient temperature).

b. Assumes that the facility operates up to 1,200 hr/yr at 100% load (equal to 33,120,000 gal/yr) of low sulfur distillate fuel oil. Annual emission limits for low sulfur distillate fuel oil combustion are based on hourly emission rates at 100% load and 0°F.

c. For all pollutants except SO_2, assumes that each combustion turbine operates 1,200 hr/yr on fuel oil and 7,560 hr/yr on natural gas at 100% load. For SO_2, assumes operation on natural gas for 8,760 hr/yr at 100% load.

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[5] The SO_2 oil firing limit of 117.1 tons on a 12-month rolling average shall apply until such time that the sulfur content of the distillate fuel oil in the storage tank drops below 0.0015% by weight. At that time, the SO_2 oil firing limit of 4.0 tons on a 12-month rolling average will apply to emission units EU01 and EU02.

[6] The SO_2 emission limit of 164.7 tons on a 12-month rolling average shall apply until such time that the sulfur content of the distillate fuel oil in the storage tank drops below 0.0015% by weight. At that time, the SO_2 emission limit of 55.2 tons on a 12-month rolling average will apply to emission units EU01 and EU02.

[7] The facility-wide SO_2 emission limit of 165.9 tons on a 12-month rolling average shall apply until such time that the sulfur content of the distillate fuel oil in the storage tank drops below 0.0015% by weight. At that time, the facility-wide SO_2 emission limit of 56.4 tons on a 12-month rolling average will apply.

<table>
<tr><th colspan="4">Table 5 - Operational and Emission Limitations</th></tr>
<tr><th>Item #</th><th>Applicable Requirements</th><th>Applicable Emission Unit</th><th>Regulatory Cite</th></tr>
<tr><td>22.</td><td>Combustion Turbine startup shall be defined as the period of time from initiation of turbine firing until steady state operation above 60% load at ambient conditions.</td><td>EU01 & EU02</td><td>NEL Startup/ Shutdown proposal dated 11/14/05</td></tr>
<tr><td>23.</td><td>Combustion Turbine shutdown shall be defined as the period from steady-state operation at or above 60% load at ambient conditions to cessation of fuel combustion in the Turbine.</td><td>EU01 & EU02</td><td>NEL Startup/ Shutdown proposal dated November 14, 2005</td></tr>
<tr><td>24.</td><td>Combustion Turbine fuel transition shall be defined as the period of time from the reduction of load below 60% load on one fuel to the achievement of compliance at steady state operation above 60% load on the other fuel at ambient conditions. Each fuel transition shall be achieved as soon as practical and in no case shall exceed 180 minutes.</td><td>EU01 & EU02</td><td>PSD Permit 044-121NH10</td></tr>
<tr><td>25.</td><td>When firing on natural gas or low sulfur distillate fuel oil, NEL shall comply with the following emission limits per each CT unit for each startup and shutdown event:
<table>
<tr><th colspan="3">Table 9 - Startup and Shutdown Emission Limits
For Each Event</th></tr>
<tr><th></th><th>CO Limit (pounds) Per Turbine</th><th>NOx Limit (pounds) Per Turbine</th></tr>
<tr><td>Startup</td><td>1,800</td><td>750</td></tr>
<tr><td>Shutdown</td><td>780</td><td>170</td></tr>
</table></td><td>EU01 & EU02</td><td>NEL Startup/ Shutdown proposal dated November 14, 2005</td></tr>
<tr><td>26.</td><td>The maximum gross heat input of auxiliary boiler shall be limited to 25.2 million British Thermal Units per hour (MMBtu/hr), HHV.</td><td>EU04</td><td>Temporary Permit TP-B-0483</td></tr>
<tr><td>27.</td><td>Operating hours for the auxiliary boiler shall be limited to 2,000 hours per consecutive 12-month period.</td><td>EU04</td><td>Temporary Permit TP-B-0483</td></tr>
<tr><td>28.</td><td>The maximum gross heat input of each of the six fuel gas heaters shall be limited to 2.4 MMBtu/hr.</td><td>EU05</td><td>Permit Application FY05-0026</td></tr>
<tr><td>29.</td><td>Operating hours for the fuel gas heaters shall not be limited.</td><td>EU05</td><td>Permit Application FY05-0026</td></tr>
<tr><td>30.</td><td>Operating hours for the emergency generator shall be limited to 500 hours during any consecutive 12-month period.</td><td>EU06</td><td>Permit Application FY05-0026</td></tr>
<tr><td>31.</td><td>Operating hours for the firewater pump shall be limited to 500 hours during any consecutive 12-month period.</td><td>EU07</td><td>Permit Application FY05-0026</td></tr>
</table>

<table>
<tr><th colspan="4">Table 5 - Operational and Emission Limitations</th></tr>
<tr><th>Item #</th><th>Applicable Requirements</th><th>Applicable Emission Unit</th><th>Regulatory Cite</th></tr>
<tr><td>32.</td><td>Opacity shall not exceed 20 percent opacity for any continuous 6-minute period.</td><td>EU04 through EU07</td><td>Env-A 2002.02</td></tr>
<tr><td>33.</td><td>For the auxiliary boiler, no more than one of the following 2 opacity exemptions shall be taken:
a. During periods of startup, shutdown and malfunction, average opacity shall be allowed to be in excess of 20 percent for one period of 6 continuous minutes in any 60 minute period; or
b. During periods of normal operation, soot blowing, grate cleaning, and cleaning of fires, average opacity shall be allowed to be in excess of 20 percent but not more than 27 percent for one period of 6 continuous minutes in any 60 minute period.</td><td>EU04</td><td>Env-A 2002.04</td></tr>
<tr><td>34.</td><td>The auxiliary boiler, fuel gas heaters, and emergency generators shall not emit particulate emissions at a rate greater than 0.30 lb/MMBTU.</td><td>EU04 through EU07</td><td>Env-A 2003.08</td></tr>
<tr><td>35.</td><td>Emissions from the auxiliary boiler, fuel gas heaters, and emergency generators shall be limited to the values listed in Table 10 below:
<table>
<tr><th colspan="7">Table 10: Maximum Hourly and 12-Month Rolling Emission Rates for Auxiliary Boiler, Fuel Gas Heaters, Emergency Generator, and Firewater Pump</th></tr>
<tr><th>Pollutant</th><th colspan="2">Auxiliary Boiler</th><th colspan="2">Six Fuel Gas Heaters Combined</th><th colspan="2">Emergency Generator & Firewater Pump</th></tr>
<tr><th></th><th>lb/hr</th><th>tpy</th><th>lb/hr</th><th>tpy</th><th>lb/hr</th><th>tpy</th></tr>
<tr><td>Nitrogen Oxides (NOx)</td><td>0.91</td><td>0.91</td><td>0.17</td><td>0.76</td><td>16.24</td><td>4.06</td></tr>
<tr><td>Particulate Matter Less than 10 Microns (PM10)</td><td>0.15</td><td>0.15</td><td>0.11</td><td>0.48</td><td>0.18</td><td>0.04</td></tr>
<tr><td>Sulfur Dioxide (SO_2)</td><td>0.09</td><td>0.09</td><td>0.11</td><td>0.47</td><td>2.92</td><td>0.73</td></tr>
<tr><td>Carbon Monoxide (CO)</td><td>0.93</td><td>0.93</td><td>0.32</td><td>1.40</td><td>2.53</td><td>0.63</td></tr>
<tr><td>Volatile Organic Compounds (NEVOCs)</td><td>0.15</td><td>0.15</td><td>0.08</td><td>0.35</td><td>0.28</td><td>0.07</td></tr>
</table>
</td><td>EU04, EU05, EU06, EU07</td><td>Temporary Permit TP-B-0483 (EU04, EU06, EU07)

Temporary Permit TP-B-0483 and NOx RACT Order (EU05)</td></tr>
<tr><td>36.</td><td>NOx emissions from each HRSG shall not exceed 0.20 lb/MMBtu as determined on a 30-day rolling average basis. The NOx emissions rate at the outlet from the HRSGs shall constitute the NOx emissions rate from the duct burner of the combined cycle system.</td><td>EU01 & EU02</td><td>40 CFR 60 Subpart Db § 60.44b(a)</td></tr>
<tr><td>37.</td><td>Ammonia injection into the catalyst bed shall be initiated only when the bed temperature meets 450°F for Natural Gas firing and 550°F for distillate oil firing.</td><td>EU01 & EU02</td><td>PSD Permit 044-121NH10</td></tr>
</table>

Table 5 - Operational and Emission Limitations			
Item #	**Applicable Requirements**	**Applicable Emission Unit**	**Regulatory Cite**
38.	Accidental Release Program Requirements (40 CFR Part 68) a. Newington Energy shall comply with all applicable requirements of 40 CFR Part 68.	Facility Wide	40 CFR 68 CAAA §112(r)(1)

VII. NOx Reasonably Available Control Technology (RACT) Requirements

A. Pursuant to Env-A 1211.12, *Emission Standards for Auxiliary Boilers*, the auxiliary boiler shall be limited to no greater than 0.20 lbs NOx per MMBtu based on a 24-hour calendar day average.

B. The fuel gas heaters shall meet the NOx RACT requirements of Env-A 1211.14, *Emission Standards and Control Options for Miscellaneous Stationary Sources.*

C. If the operating hours for an emergency generator are equal to or greater than 500 hours or if the combined NOx emissions from all emergency generators are equal to or greater than 25 tons per consecutive 12-month period, NEL shall meet the requirements of Env-A 1211.11, *Emission Standards and Control Options for Emergency Generators*.

VIII. Emission Offset Requirements

A. NEL shall prior to commencing operation 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.

B. NOx Budget Allowances obtained in accordance with Condition IX of this permit may be used as Emission Offsets at a 1.0 to 1.0 ratio (i.e. one ton of NOx allowances shall equal one ton of NOx emission offset), however the overall emission offset ratio must remain at 1.2 to 1.0 in accordance with A. above.

IX. NOx Budget Allowances

A. NEL shall comply with the applicable requirements of Chapter Env-A 3200 *NOx Budget Trading Program*.

B. NEL shall obtain sufficient NOx Budget Allowances to cover all ozone season (May 1 through September 30 of each calendar year) NOx emissions.

C. NEL may utilize NOx Budget allowances to satisfy the Emission Offset Requirements of Condition VIII above.

X. Federal Acid Rain Requirements

A. In accordance with 40 CFR 72, *Federal Acid Rain Requirements*, NEL been designated as a Phase II New Affected Unit. NEL submitted a Phase II Acid Rain Application on July 2, 1998 and was issued Acid Rain Permit # TV-AR-005 on July 19, 2001.

X. Federal Acid Rain Requirements (continued)

B. NEL shall acquire SO_2 allowances in the amount of one allowance for each ton of SO2 emitted in accordance with 40 CFR 72.

C. NEL shall maintain and operate continuous emission monitoring systems that meet the applicable requirements of 40 CFR 75.

D. NEL shall comply with all applicable requirements of 40 CFR 72, 73, 75, 77 and 78.

XI. Monitoring and Testing Requirements

The Permittee is subject to the monitoring and testing requirements as specified below:

Table 11 - Monitoring/Testing Requirements

Item #	Parameter	Method of Compliance	Frequency of Method	Device	Regulatory Cite
1.	Sulfur content of Natural Gas	a. The owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbines if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u) provided the facility uses **<u>one</u>** of the following sources of information to make the required compliance demonstration: i. The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20 grains/100 scf or less; or ii. Representative fuel sampling data which shows that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D of 40 CFR 75 is required. b. Pursuant to 40 CFR 75, Appendix D, Section 2.3, the owner or operator may demonstrate compliance with the 0.5 gr/100 scf sulfur limit set for Acid Rain Program sources combusting pipeline quality natural gas (as defined in 40 CFR 72.2) by annually sampling the natural gas for sulfur content or by obtaining a valid contract or tariff sheet to verify that the total sulfur content of the natural gas is less than or equal to 0.5 gr/100 scf. The above procedures will also satisfy the requirements of Env-A 806.03 *Test Methods for Gaseous Fuels* provided that the annual sampling is done in accordance with one of the following test methods:	As specified	EU01 & EU02	40 CFR 60.334(h)(3) Env-A 806.03 & 40 CFR 75, Appendix D, Section 2.3

Table 11 - Monitoring/Testing Requirements					
Item #	Parameter	Method of Compliance	Frequency of Method	Device	Regulatory Cite
		i. ASTM D 1072-90; ii. ASTM D 4084-94; iii. ASTM D 3246-96; iv. ASTM D 5504-01; or v. ASTM D 6228-98.			
2.	Sulfur content of fuel oil	While firing fuel oil, the owner or operator shall use vendor analyses to satisfy the sulfur monitoring requirements of 40 CFR 60, Subpart GG. The sulfur content of all the fuel oil supplied to the owner or operator must be accounted for through vendor analysis and must meet the applicable limits. The analysis conducted by the vendor must have been conducted using the methods specified in Env-A 806.02, Table 8.1, Test Methods for Liquid Fuels.	As specified	EU01 & EU02	40CFR60.334 and Env-A 806.02
3.	CO	CEMS	Continuously	EU01 & EU02	PSD Permit 044-121NH10
4.	NOx	CEMS	Continuously	EU01 & EU02	PSD Permit 044-121NH10
5.	PM10, VOC, H2SO4	Stack Test	Upon request by DES	EU01 & EU02	Env-A 801.02
6.	Oxygen	The oxygen (O_2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emission rates to 15% O_2.	Continuously	EU01 & EU02	PSD Permit 044-121NH10
7.	Fuel flow	NEL shall measure and record the fuel flow rate of fuel combusted by each combustion turbine. The fuel flow rate shall be measured with an in-line fuel flow meter and automatically recorded with a data acquisition and handling system.	Continuously	EU01 & EU02	40 CFR 75, Appendix D, Section 2.1
8.	Ammonia slip	CEMS	Continuously	EU01 & EU02	PSD Permit 044-121NH10
9.	Calibration of Ammonia CEM	NEL shall calibrate the Ammonia CEM on both the CT units on a quarterly basis with a certified bottle of Ammonia calibration gas and adjust the CEM readings accordingly. The results of this quarterly audit shall be submitted in the quarterly excess emission reports required by Env-A 808.11.	Quarterly	EU01 & EU02	DES approval letter dated October 2, 2002
10.	QA/QC Plan Requirements	The Owner or Operator of a source required to operate or maintain an opacity or gaseous CEM system shall: a. Maintain a quality assurance/quality control (QA/QC) plan, which shall contain written procedures for	Annually	EU01 & EU02	Env-A 808.06

Table 11 - Monitoring/Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Device**	**Regulatory Cite**
		implementation of its QA/QC program for each CEM system; b. Review the QA/QC plan and all data generated by its implementation at least once each year; c. Revise or update the QA/QC plan, as necessary, based on the results of the annual review, by documenting any changes made to the CEM or changes to any information provided in the monitoring plan; d. Make the revised QA/QC plan available for on-site review by the Division at any time; and e. Within 30 days of completion of the annual QA/QC plan review, certify in writing that the Owner or Operator will continue to implement the source's existing QA/QC plan or submit in writing any changes to the plan and the reasons for the change.			
11.	General Audit Requirements	a. Required quarterly audits shall be done anytime during each calendar quarter, but successive quarterly audits shall occur no more than 4 months apart; b. Within 30 calendar days following the end of each quarter, the owner or operator of the source shall submit to the Division a written summary report of the results of all required audits that were performed in that quarter, in accordance with the following: i. For gaseous CEM audits, the report format shall conform to that presented in 40 CFR 60, Appendix F, Procedure 1, section 7; ii. For opacity CEM audits, the report format shall conform to that presented in EPA-600/8-87-025, April 1992, "Technical Assistance Document: Performance Audit Procedures for Opacity Monitors" and c. The Owner or Operator shall notify the Division at least 30 days prior to the performance of a Relative Accuracy Test Audit (RATA).	Quarterly	EU01 & EU02	Env-A 808.07
12.	Gaseous CEM Audit Requirements	a. Audit requirements for gaseous CEM systems shall be performed in accordance with procedures described in 40 CFR 60, Appendix F and Env-A 808.08. b. For a time-shared gaseous CEM system, the owner or operator shall perform the following audits: i. An annual RATA to check the analyzer at any sampling point; and ii. Cylinder Gas Audits or Relative Accuracy Audits at all sampling points for each of the	As Specified	EU01 & EU02	Env-A 808.08

Table 11 - Monitoring/Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Device**	**Regulatory Cite**
		remaining 3 quarterly audits.			
13.	Opacity CEM Audit Requirements	Audit requirements for opacity CEM systems shall be performed in accordance with procedures described in 40 CFR 60, Appendix B, Specification 1 and Env-A 808.09.	Quarterly	EU01 & EU02	Env-A 808.09
14.	Data Availability Requirements	a. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 90% on a calendar quarter basis. b. The percentage CEM data availability for opacity and all gaseous concentration monitors shall be maintained at a minimum of 75% for any calendar month.	N/A	EU01 & EU02	Env-A 808.10
15.	Data availability Calculations	NEL shall use the following equation for calculating percentage data availability: $$PercentageDataAvailability = \frac{(VH + CalDT)x100}{(OH - AH)}$$ Where: VH = Number of valid hours of CEM data in a given time period for which the data availability is being calculated when the plant is in operation; CalDT = Number of hours, not to exceed one hour per day, during facility operation when the CEM is not operating due to the performance of the daily CEM calibrations as required in 40 CFR 60, Appendix F or 40 CFR 75, Appendix B, section 2.1; OH = Number of facility operating hours during a given time period for which the data availability is being calculated; and AH = Number of hours during facility operation when the performance of quarterly audits as required by those procedures specified in Env-A 808.08 or Env-A 808.09, as applicable, require that the CEM be taken out of service in order to conduct the audit.	As specified	EU01 & EU02	Env-A 808.10
16.		<u>Concentration Measurements for Auxiliary Boiler and Emergency Generators:</u> Following the performance of tune up activities as specified in Env-A 1211 (NOx RACT), the owner or operator of a small boiler or an emergency generator as specified in Env-A 803.03 shall perform applicable gaseous concentration measurements for nitrogen oxides (NOx), carbon monoxide (CO), and oxygen (O_2) on the Auxiliary Boiler, Diesel Emergency Generator, and Diesel Emergency Fire Pump as specified below: a. Any of the following monitors shall be acceptable for	As specified in regulation	EU04, EU06, & EU07	Env-A 803.04

Table 11 - Monitoring/Testing Requirements					
Item #	**Parameter**	**Method of Compliance**	**Frequency of Method**	**Device**	**Regulatory Cite**
		making the gaseous concentration measurements: i. All analyzers meeting the specifications set forth in the applicable sections of 40 CFR 60, Appendix B, Performance Specifications 2 through 4; ii. Portable extractive monitors using an electrochemical sensor for performing the gas concentration measurement; and iii. Alternative monitors, if written technical information is provided to the division demonstrating that the analyzer in the alternative monitor is at least as accurate as the analyzer using the electrochemical sensor; b. A concentration monitor shall be operated following the operating procedures specified by the manufacturer; c. Measurements shall be taken at one minute intervals at each representative operation condition over a minimum of a 15-minute period following achievement of stable operation; d. All measurements shall be documented and averaged over the period of testing; e. Prior to and following measurement, the owner or operator shall perform, following the manufacturer's recommended procedures, 2 calibrations as follows: i. A calibration with a gas containing between 0% and 20% of the expected concentration of the gas being measured, based on manufacturer’s data or EPA-published emission factors for the device; and ii. A calibration with a gas containing between 80% and 150% of the expected concentration of the gas being measured, based on manufacturer’s data or EPA-published emission factors for the device; f. All calibration data shall be recorded and kept on-site; g. Concentration measurements shall be reported on a dry basis; and h. If a direct measurement is on a wet basis, the basis for the percentage moisture used and the correction calculation to dry basis shall be documented.			

XII. Recordkeeping Requirements

The Permittee shall be subject to the recordkeeping requirements identified in Table 12 below:

Table 12 - Applicable Recordkeeping Requirements

Item #	Applicable Recordkeeping Requirement	Records Retention/ Frequency	Applicable Emission Unit	Regulatory Cite
1.	NEL shall retain records of all required monitoring data, recordkeeping and reporting requirements, and support information for a period of at least 5 years from the date of origination.	Retain for a minimum of 5 years	Facility Wide	Env-A 902
2.	NEL shall maintain records of the following information by device on a calendar day basis: a. Hours of operation, including any startup, shutdown, or malfunction. b. Time frames and ambient conditions when duct burner supplemental fuel firing is utilized. c. The total daily fuel consumption by device (in cubic feet for natural gas and in gallons for fuel oil). d. The total daily amount of ammonia, in pounds, used in the SCR Systems. e. The running totals of c. and d. above for the previous thirty-day period.	Maintain on a continuous basis	EU01 & EU02	PSD Permit 044-121NH10
3.	NEL shall maintain the following records: a. Records of stack testing for PM, SO_2, NOx, CO, VOCs, NH_3, and H2SO4; and b. Records of each start-up and shutdown event.	Maintain on a continuous basis	EU01 & EU02	Env-A 906.01
4.	<u>General Recordkeeping Requirements for Combustion Devices</u> a. Amount of fuel consumed; b. Type of fuel consumed; c. Sulfur content as percent sulfur by weight of fuel or in grains per 100 cubic feet of fuel; and d. Hours of operation of each combustion device so that the distribution of fuel among each combustion device can be estimated.	Monthly	EU01 EU02 EU04 EU05 EU06 EU07	Env-A 903.03
5.	<u>General Recordkeeping Requirements for Sources with Continuous Emissions Monitoring Systems</u> NEL shall maintain records for the continuous emission monitoring systems in accordance with Env-A 800 and all applicable federal regulations.	Maintain on a continuous basis	EU01 & EU02	Env-A 903.04

Table 12 - Applicable Recordkeeping Requirements				
Item #	**Applicable Recordkeeping Requirement**	**Records Retention/ Frequency**	**Applicable Emission Unit**	**Regulatory Cite**
6.	General NO_x Recordkeeping NEL shall record the following information and maintain such records at the facility: a. Identification of each combustion device; b. Operating schedule during the *high ozone season* (May 1 to September 30, inclusive) for each combustion device identified in Item #6.a above, including: i. Hours of operation per calendar month; ii. Days of operation per calendar month; iii. Number of weeks of operation; iv. Type and amount of fuel burned for each combustion device; v. Heat input rate in million BTUs per hour; vi. The actual NO_x emissions from each combustion device for the calendar year in tons and a high ozone day in pounds per day during that calendar year; and vii. The emission factors and the origin of the emission factors used to calculate the NO_x emissions.	On a continuous basis	Facility wide	Env-A 905.02
7.	Additional Recordkeeping Requirements [Env-A 906]. NEL shall maintain the following records, as necessary, to demonstrate compliance with all state and federal statutes, rules, regulations, and permits: a. The operating hours of the auxiliary boiler to determine compliance with Condition III of this permit (item 2 of table 2 for EU04); b. The operating hours of the emergency generator to determine compliance with Condition III of this permit (item 2 of table 2 for EU06); c. The operating hours of the firewater pump to determine compliance with Condition III of this permit (item 2 of table 2 for EU07); d. The amount of fuel combusted in the auxiliary boiler during **each day** [40 CFR 60.48c]; e. The occurrence and duration of any startup, shutdown, or malfunction in the operation of the auxiliary boiler or any periods during which a monitoring device is inoperative [40 CFR 60.7(b)].	Monthly, unless specified otherwise	EU04 EU06 EU07	Env-A 906 40 CFR 60 Subpart Dc (EU04)
8.	Recordkeeping for Sources or Devices with Add-on NOx Air Pollution Control Equipment NEL shall record and maintain the following information for the add-on NOx air pollution control equipment: a. The air pollution control device identification number, type, model number, and manufacturer; b. Installation date;	On a continuous basis	EU01 & EU02	Env-A 905.03

Table 12 - Applicable Recordkeeping Requirements				
Item #	Applicable Recordkeeping Requirement	Records Retention/ Frequency	Applicable Emission Unit	Regulatory Cite
	c. Unit(s) controlled; d. Type and location of the capture system, capture efficiency percent, and method of determination; e. Information as to whether or not the air pollution control device is always in operation when the fuel burning device it is serving is in operation; and f. The destruction or removal efficiency of the add-on air pollution control equipment, including the following information: i. Destruction or removal efficiency, in percent; ii. Current primary and secondary equipment control information codes; iii. Date tested; and iv. The method of determining destruction or removal efficiency, if not tested.			
9.	<u>Air Pollution Control Device Operational Records</u> The Owner or Operator shall maintain records of all malfunctions, routine maintenance, and other downtimes of any air pollution control equipment in whole or part. These records must be available for review by DES/EPA upon request.	At each occurrence	PCE1, PCE2 & PCE3	Env-A 906.01
10.	<u>Recordkeeping Requirements for Permit Deviations [Env-A 911].</u> The recordkeeping requirements for permit deviations can be found in Condition XIV. of this permit.	At each occurrence	Facility wide	Env-A 911

XIII. Reporting Requirements

The Permittee shall be subject to the reporting requirements identified in Table 13 below:

Table 13 - Applicable Reporting Requirements				
Item #	Reporting Requirements	Frequency of Reporting	Applicable Emission Unit	Regulatory Cite
1.	The Owner or Operator shall submit an annual emissions report to the Division on or before April 15^{th} of the following year. For example, the annual emissions report for calendar year 2006 shall be submitted on or before April 15, 2007.	Annually (no later than April 15^{th} of the following year)	Facility Wide	Env-A 907.01
2.	The annual emissions report required by Item #1 above shall include the following information: a. The actual emissions of the facility and the methods used in calculating such emissions in accordance with Env-A 705.02; b. For combustion devices, all information required by Item 4 of	Annually (no later than April 15^{th} of the following year)	Facility Wide	Env-A 907.01

Table 13 - Applicable Reporting Requirements				
Item #	**Reporting Requirements**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	Table 12 above; and c. Actual emissions speciated by individual regulated air pollutant**,** including a breakdown of VOC emissions by compound.			
3.	NEL shall submit a quarterly report containing all information required by item #2 of Table 12. Such quarterly reports shall be submitted to DES no later than 30 days following the end of each calendar quarter.	Quarterly	EU01 & EU02	PSD Permit 044-121NH10
4.	<u>NO_x Reporting Requirements</u> The Owner or Operator shall submit to the Director, annually (no later than April 15th of the following year), a report of data required by Item #5 of Table 12.	Annually (no later than April 15th of the following year)	Facility wide	Env-A 909
5.	<u>Quarterly Reports</u> The Owner or Operator shall submit quarterly emission reports containing the following information: a. Excess emission data recorded by the CEM system, including: i. The date and time of the beginning and ending of each period of excess emission; ii. The magnitude of each excess emission; iii. The specific cause of the excess emission; and iv. The corrective action taken. b. If no excess emissions have occurred, a statement to that effect; c. For gaseous measuring CEM systems, the daily averages of the measurements made and emission rates calculated; d. A statement as to whether the CEM system was inoperative, repaired, or adjusted during the reporting period; e. If the CEM system was inoperative, repaired, or adjusted during the reporting period, the following information: i. The date and time of the beginning and ending of each period when the CEM was inoperative; ii. The reason why the CEM was inoperative; iii. The corrective action taken; and iv. The percent data availability calculated in accordance with Env-A 808.10 for each flow, diluent, or pollutant analyzer in the CEM system. f. For all “out of control periods” the following information;	Quarterly (no later than 30 days following the end of each quarterly reporting period)	EU01 & EU02	Env-A 808.11 & Env-A 808.13

Table 13 - Applicable Reporting Requirements				
Item #	**Reporting Requirements**	**Frequency of Reporting**	**Applicable Emission Unit**	**Regulatory Cite**
	i. The times beginning and ending the out of control period; ii. The reason for the out of control period; and iii. The corrective action taken. g. The date and time beginning and ending each period when the source of emissions which the CEM system is monitoring was not operating. h. The span value, as defined in Env-A 101.255, of each analyzer in the CEM system and units of measurement for each instrument; and i. When calibration gas is used, the following information: i. The calibration gas concentration; ii. If a gas bottle was changed during the quarter: A. The date of the calibration gas bottle change; B. The gas bottle concentration before the change; C. The gas bottle concentration after the change; and D. The expiration date for all calibration gas bottles used.			
6.	NEL shall report the CO & NOx emissions from each unit for each startup or shutdown event.	Quarterly	EU01 & EU02	Env-A 910
7.	NEL shall notify DES in writing of the date when the average sulfur content of the low sulfur distillate fuel oil in the storage tank drops below 0.0015% by weight (i.e., date when new SO_2 emission limits for EU01 and EU02 become effective).	Within 30 days after sulfur content of distillate fuel oil in storage tank drops below 0.0015% by weight	EU01 & EU02	Env-A 910

<u>THIS SECTION LEFT BLANK INTENTIONALLY</u>

XIV. Permit Deviation Recordkeeping and Reporting Requirements

A. Env-A 101, *Definitions*:

1. A *permit deviation* is any occurrence that results in an excursion from any emission

limitation, operating condition, or work practice standard as specified in either a Title V permit, state permit to operate, or temporary permit issued by the Division.

2. An *excess emission* is an air emission rate which exceeds any applicable emission limitation.

B. Env-A 911.03, *Recordkeeping Requirements*: 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 of the occurrence;
e. The specific device that contributed to the permit deviation; and
f. Any corrective or preventative measures taken.

C. Env-A 911.04(a), *Reporting Requirements*: If the permit deviation referenced in Condition XIV.B <u>does not</u> cause excess emissions, but continues for a period greater than 9 consecutive days, the Owner or Operator shall notify the Division by telephone (603 271-1370), fax (603 271-7053), or e-mail (pdeviations@des.state.nh.us) 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 taken.

D. Env-A 911.04(b): If the permit deviation referenced in Condition XIV.B does cause excess emissions, the Owner or Operator shall:

1. Notify the Division of the permit deviation and excess emissions by telephone, fax, or e-mail within 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

2. Submit a written report to the Division within 10 days of discovery of the permit deviation reported in Condition XIV.D.1, above, which 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;

D. 2. i. Corrective action taken to date;
j. Preventative measures taken to prevent future occurrences;
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 procedure used to quantify the excess emissions.

E. 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:

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

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

F. The Owner or Operator shall report to the Division, annually by April 15th, the following information:

1. A summary of all permit deviations reported to the Division pursuant to Conditions XIV.C and/or XIV.D, for the reporting period; and

2. A list of all permit deviations recorded during the previous year pursuant to Condition XIV.B.2.

XV. 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 facility.

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 facility 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 XV.B.
DPT = The dollar per ton fee calculated by the Division as specified in Env-A 705.03(e).

XV. Emission-Based Fee Requirements (continued)

D. Env-A 705.04, *Payment of Emission-based Fee*: The Owner or Operator shall submit, to the Division, payment of the emission-based fee by April 15th for emissions during the previous calendar year. For example, the emission-based fee for calendar year 2006 shall be submitted on or before April 15, 2007.