	PERMIT APPLICATION REVIEW SUMMARY	**New Hampshire Department of Environmental Services** **Air Resources Division** **P.O. Box 95, 29 Hazen Drive** **Concord, NH 03302-0095** **Phone: 603-271-1370 Fax: 603-271-7053**

Facility:	NAEA Newington Energy LLC			**Engineer:**	Padmaja Baru	
Location:	200 Shattuck Way, Newington					
AFS #:	3301590793	**Application #:**	FY03-0331 & FY06-0114	**Date:**	4/13/2010	Page 1 of 12

DATE APPLICATION RECEIVED

- Title V Application # FY03-0331 was received on June 20 2003; Completeness letter was sent on October 9, 2003. Application shield is applicable.

- Acid rain permit renewal application # FY06-0114 was received on October 5, 2006.

PROJECT DESCRIPTION

The main purpose of this permit action is to issue a Title V operating permit. Please note that the Title V permit includes acid rain program related permit conditions. Also, a copy of the acid rain application is attached to the permit.

CHANGES FROM THE PREVIOUS PERMIT

1. Cooling tower (EU03) - Based upon pump specifications, the correct circulation rate of the cooling tower is 150,000 gallons/minute. Additionally, the facility's NPDES permit has been revised to increase the salinity (i.e., TDS concentration) from 56,000 ppmw to 66,000 ppmw.

2. Table 5, Item #16 - Facility-wide emission limit for PM_{10} was adjusted to include 11.2 tpy from cooling tower. PM_{10} limit = 119.1 tpy.

3. The Title V permit clarifies that the H_2SO_4 emission limit of 14.2 lb/hr (for oil firing) will 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 H_2SO_4 oil firing limit of 0.5 lb/hr will apply to emission units EU01 and EU02.

4. In June 2009, Newington Energy LLC (NEL) was notified that the Owner/Operator of the LNG terminal in New Brunswick, Canada may be occasionally injecting LNG into the natural gas (NG) pipeline. NEL contacted DES on June 19, 2009 expressing concern that the injection of LNG may cause higher sulfur concentrations than is allowed by the PSD permit (i.e., 2.5 gr/100 scf). Please note that NEL would have no prior knowledge as to when the LNG would be injected in the natural gas pipeline nor has any control over the quality of the pipeline natural gas. The NG supplier cannot always guarantee that the sulfur content of the natural gas will be less than 2.5 gr/100 scf. Also note that this issue not only affects NEL but any other source in New Hampshire or Maine on the Maritimes & Northeast pipeline. In order to address this issue, Items 10 & 11 of Table 5 in TP-B-0526 were combined into one permit condition (Item #2 of Table 5 in the Title V permit) to read as follows:

   > NEL is permitted to combust natural gas and ultra low sulfur distillate oil in the combustion turbines. The sulfur content of distillate oil shall be limited to 0.0015% by weight. As of December 12, 2006 (which was the issuance date for TP-B-0526), NEL shall only receive distillate oil that complies with the transportation grade sulfur limit of 0.0015 percent by weight. NEL is permitted to use the remainder of previously purchased distillate oil with a maximum sulfur content of 0.05 percent by weight.

5. In the original PSD Permit 044-121NH10, SO_2 emission limits of 0.0036 lb/MMBtu and 6.3 lb/hr for natural gas combustion did not take into account the conversion factor of 2 (i.e., the ratio of lb SO_2/lb S). The correct values for these limits are included in the Title V permit. They are calculated using Equation D-1h (40 CFR 75, App. D) as shown below:

   $$ER = [2/7000] \times [10^6] \times [S_{total}/GCV]$$

   where:

   ER = SO_2 emission rate for natural gas combustion, lb/MMBtu

   S_{total} = Total sulfur content of the natural gas, gr/100 scf *(2.5 grains/100 scf)*

   GCV = Gross calorific value of natural gas, Btu/100 scf *(100,000 Btu/100 scf)*

7000 = Conversion of grains to lbs

2.0 = ratio of lb SO_2/lb S

10^6 = Conversion factor (Btu/MMBtu)

SO_2 emission rate = [2/7000] x [10^6] x [2.5/100,000] = 0.0071 lb/MMBtu

SO_2 emission rate = 0.0072 lb/MMBtu x 2115 MMBtu/hr (HHV for NG) = 15.1 lb/hr

Please note that only the short-term emission limits for SO_2 were revised and no changes were made to annual emission limits in Table 5C (except for PM_{10} as explained in note #1 above) of the Title V permit.

6. Table 5, Item #22 - NEL requested auxiliary boiler operating hour limit of 2000 hours/yr be revised to an equivalent natural gas throughput limit. The maximum firing rate of 25,200 ft^3/hr for 2,000 hrs/yr yields a maximum annual natural gas consumption rate of 50,400,000 ft^3/yr in the auxiliary boiler. This change will not affect any existing short or long term emission limits.

7. Table 5, Item #31 - Based upon manufacturer's recommendations and field testing of the catalyst, NEL proposed to revise the temperatures that the catalyst bed must achieve prior to injecting ammonia: 430˚F for gas firing and 518˚F for oil firing.

8. Table 7, Item #6b - The original permit for the facility contained ambient temperature conditions for firing of the duct burners. These ambient temperature limits were removed during subsequent permit revisions (TP-B-0526 amended on 11/26/2008) and therefore, maintaining records of ambient conditions during duct firing is no longer necessary to demonstrate compliance. Item #6b of Table 7 was updated accordingly.

PERMIT APPLICATION REVIEW SUMMARY						
Facility:	NAEA Newington Energy			**Engineer:**	Padmaja Baru	
Location:	200 Shattuck Way, Newington, NH					
AFS #:	3301590793	**Application #:**	FY03-0331 & FY06-0114	**Date:**	4/13/2010	Page 3 of 12

FACILITY DESCRIPTION

NAEA Newington Energy, LLC 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.

During limited 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. The following emission units are covered by the permit:

Device	Manufacturer, Model, Installation Date	Control device	Maximum Design Capacity and Fuel Type(s)
EU01 - Combustion Turbine #1 (designated as CT #1) with Heat Recovery Steam Generator	General Electric Frame 7FA Date installed: June 2002	Dry low-NOx (DLN) in conjunction with Selective catalytic Reduction (SCR) - for natural gas combustion Water injection system in conjunction with SCR - for distillate oil combustion Purpose - to control NOx	1. Combustion Turbines #1 and #2 shall each be limited to 2,115 MMBtu/hr (HHV) gross heat input while firing natural gas or 2,218 MMBtu/hr (HHV) gross heat input while firing low sulfur distillate fuel oil. 2. Supplemental fuel firing in each HRSG shall be limited to 177.7 MMBtu/hr (HHV) gross heat input. Fuel is limited to natural gas only.
EU02 - Combustion Turbine #2 (designated as CT #2) with Heat Recovery Steam Generator	General Electric Frame 7FA Date installed: June 2002		
EU03 - 10-cell Wet Mechanical draft cooling tower equipped with high efficiency drift eliminators	Marley Wet Mechanical draft Cooling Tower Date installed: 2002	Each cell is equipped with a single layer of Marley drift eliminator plus a suspended layer of Marley honeycomb cooling tower fill. Purpose - To minimize water drift losses and plume visibility	1. Cooling Tower drift = 0.0005% of the circulating water flow rate. 2. Circulation Rate = 150,000 gallons/minute
EU04 - Auxiliary Boiler	Hurst Boiler Model No. S2XID-G-600-2001 Date installed: June 2002	N/A	25.2 MMBtu/hr Natural gas - equivalent to 25,200 scf/hr (HHV)
EU05 - Six Fuel Gas Heaters	Laars Model No. 2400 Date installed: August 2004	N/A	2.4 MMBtu/hr - each heater Natural gas - equivalent to 2,400 scf/hr (HHV) Each fuel gas heater is equipped with a low-NOx burner.
EU06 - Diesel Emergency Generator	Cummins Model No. QSX15-G9 Installed June 2002	N/A	5.2 MMBtu/hr (HHV) - diesel fuel (No. 2 oil)
EU07 - Diesel Firewater Pump	John Deere Model No. JDFP-06WR Installed June 2002	N/A	1.9 MMBtu/hr (HHV) - diesel fuel (No. 2 oil)

PERMITTING HISTORY

1. Temporary Permit TP-B-0526 - issued on December 12, 2006. This permit established permit conditions for startup, shutdown and fuel transition. This permit also increased the fuel oil limit for the combustion turbines. A significant amendment was issued on 11/26/08 to incorporate the changes requested by NEL. Please see the Permit Application Review Summary associated with Application #08-0049 for details.
2. NOx RACT Order ARD-04-001 - issued on June 20, 2007. This NOx RACT Order covered the six fuel gas heaters.
3. Temporary Permit TP-B-0483 - issued on December 4, 2001. This permit covered one Natural Gas-Fired Auxiliary Boiler, Eight Natural Gas-Fired Fuel Gas Heaters[1], one Diesel-Fired Emergency Generator and one Diesel-Fired Firewater Pump.
4. Phase II Acid Rain Permit TV-AR-005 - issued on July 19, 2001.
5. PSD Permit 044-121NH10 & Temporary Permit FP-T-0036 - issued on April 26, 1999.

EMISSION CALCULATIONS

Annual emission limits are summarized in the tables below:

Maximum 12-Month Rolling Emissions Limits				
Pollutant	**Maximum Rate on Natural Gas (for two CTs combined) (tons)**	**Maximum Rate on Fuel Oil (for two CTs combined) (tons)**	**Maximum Rate for Two CTs Combined on Both Fuels (tons)**	**Facility wide Emission Limits[2] (tons)**
NOx	151.4	93.1	223.8	229.5
SO_2	55.2	117.1[3] 4.0	164.7[4] 55.2	165.9[5] 56.4
CO	464.3	126.0	526.7	529.7
PM_{10}	96.4	24.0	107.2	119.1[6]
Sulfuric Acid Mist	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

[1] The eight fuel gas heaters (each 2.0 MMBtu/hr) were replaced by six natural gas fired fuel gas heaters (each 2.4 MMBtu/hr).
[2] Includes emissions from combustion turbines, cooling tower, auxiliary boiler, fuel gas heaters, emergency generator and fire pump combined.
[3] The SO_2 emission 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.
[4] 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.
[5] 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.
[6] Includes 11.2 tpy from cooling tower.

Maximum Hourly and 12-Month Rolling Emission Rates for Auxiliary Boiler, Fuel Gas Heaters, Emergency Generator and Firewater Pump						
Pollutant	**Auxiliary Boiler**		**Six Fuel Gas Heaters Combined**		**Emergency Generator & Firewater Pump**	
	lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
NOx	0.91	0.91	0.17	0.76	16.24	4.06
PM_{10}	0.15	0.15	0.11	0.48	0.18	0.04
SO_2	0.09	0.09	0.11	0.47	2.92	0.73
CO	0.93	0.93	0.32	1.40	2.53	0.63
VOCs	0.15	0.15	0.08	0.35	0.28	0.07

Notes:

1. Annual emissions for the auxiliary boiler are based on 50,400,000 ft^3/yr.
2. Annual emissions for the emergency generator and fire pump are based on 500 hours/yr.

Cooling Tower

The steam that leaves the steam turbine is condensed to water in the condenser. Cooling water to the condenser is supplied by the cooling tower which uses brackish water from the Piscataqua River for the makeup water source. This source is a tidal river and the makeup water is expected to have the saline content approximately that of seawater. The Cooling tower is a 10-cell Wet Mechanical draft cooling tower equipped with high efficiency drift eliminators. Cooling tower drift is limited to 0.0005% of the circulating water flowrate.

Circulation rate of cooling water in the cooling tower = 150,000 gal/min
Total Dissolved Solids (TDS) content of cooling tower water = 66,000 mg/L (NEL's NPDES permit limit)
Fraction of PM_{10} emissions as a percentage of total particulate matter = 10.4% (Source: Title V application)
Drift factor = 0.0005% (permit limit)
PM_{10} emissions = 66,000 mg/L x 150,000 gal/min x 60 min/hr x 3.78 L/gal x 1 lb/453,600 mg x 0.0005% x 10.4%
= 2.57 lb/hr & 11.3 tpy

INSIGNIFICANT ACTIVITIES

1. Twenty one Natural gas fired space heaters; Each heater is rated at less than 1 MMBtu/hr
2. Two small diesel storage tanks (each less than 500 gallons)
3. Lube oil system ventilation
4. Small tanks and drums containing hydrocarbon products
5. Boiler water treatment
6. Boiler cleaning
7. Anhydrous ammonia storage tank
8. 1,000,000 gal distillate fuel oil storage tank[7]

[7] Vapor pressure of fuel oil is less than 1.52 psi and therefore the storage tank is not subject to VOC RACT. Also the vapor pressure is less than 3.5 kPa and therefore the tank is not subject to NSPS subpart Kb.

MODELING

NEL is in compliance with NAAQS and Env-A 1400. Please see modeling memos dated March 13, 2006 and April 19, 2006, and also the *Final Determination* document dated April 26, 1999 associated with the PSD permit.

In April/May 2009, NEL installed a rain sleeve on auxiliary boiler stack. In September 2008, DES ran AERMOD to determine if the change in auxiliary boiler stack configuration at Newington Energy would result in an increase in ambient air concentrations. The model predicted a slight reduction in predicted ambient air concentrations compared to the previous stack configuration. Therefore, additional modeling is not required.

On September 25, 2009, NEL submitted comments on the draft Title V permit and noted corrections to the circulation rate of the cooling tower and the salinity of the cooling water. These revisions resulted in a slightly different PM_{10} emission rate for the cooling tower than the rate that was modeled at the time of original Title V application. Results of air dispersion modeling conducted by DES showed that the facility is in compliance with NAAQS. Please see modeling memo dated January 5, 2010 for more details.

EMISSION TESTING

1. Compliance stack tests conducted in September, October & December 2002 showed compliance with PSD permit limits for PM_{10}, SO_2, NOx, CO, Opacity, VOCs and NH_3.
2. Compliance stack test for Sulfuric acid mist was conducted in April 2005. Stack test results showed compliance with the permit limit of 0.0116 lb/MMBtu for H_2SO_4 (i.e., 22.35 lb/hr).
3. Cooling Tower drift tests were conducted on September 5-8, 2003. The tests showed compliance with the permit limit of 0.0005% drift rate.
4. Annual RATA tests for CEM systems were conducted in May 2009. These tests showed CEM systems meet the accuracy criteria set forth in Env-A 808, 40 CFR 60 and 40 CFR 75.

MONITORING REQUIREMENTS

1. NOx - Continuous emissions monitoring system (CEMS) is required under 40 CFR 75
2. CO CEMS - required by PSD permit
3. Ammonia CEMS - required by PSD permit
4. SO_2 - Use 40 CFR 75, Appendix D to calculate the emissions
5. CO_2 - Use 40 CFR 75, Appendix G to calculate the emissions
6. Fuel flow - Monitor continuously in accordance with 40 CFR 75, Appendix D, Section 2.1
7. O_2 - Monitor continuously (40 CFR 75)
8. Opacity - NEL operates a continuous opacity monitoring system as required by the original PSD permit. As per 40 CFR 75, gas-fired units are not required to operate COMS.

Note: As of the issuance date of this permit, both the combustion turbines at NEL are classified as "Gas-fired units" as per 40 CFR 72, Section 72.2 *Definitions*. Whenever the unit previously categorized as gas-fired unit is recategorized as another type of unit by changing its fuel mix, the Owner or Operator shall install, operate and certify a continuous opacity monitoring system by December 31 of the following calendar year.

9. Conduct quarterly audits and annual RATA for the CEMS in accordance with Env-A 808, 40 CFR 60 and 40 CFR 75.
10. The latest CEM QA/QC plan (Monitoring plan) was submitted by NEL on 2/18/2009.

COMPLIANCE STATUS

Site visits/Inspections

Date	Description
March 19, 2009	On-site full compliance evaluation was conducted by Alan Moulton. Reporting issues were noted.
August 25, 2008	Site visit was conducted by Padmaja Baru and Muriel Lajoie.
February 12, 2007	Off-site full compliance evaluation was conducted by Ray Walters. Minor problems regarding the late submission of quarterly reports were noted in the inspection report.

Reports

- Annual emissions report for 2009 was submitted on March 29, 2010.
- Annual compliance certification report (for 2009) was submitted on February 1, 2010.
- Semi-annual permit deviation report (for July 1, 2009 - December 31, 2009) was submitted on January 29, 2010.

Fees

Annual emission reports and fees for the facility are current through 2009.

Application Fees

Not applicable

REVIEW OF REGULATIONS

State Regulations

Env-A 300 AAQS; Facility is in compliance

Env-A 600, *Permitting*

- 607.01(a) - Applicable to EU01, EU02 & EU04
- 607.01(d) - Applicable to EU06 & EU07
- 607.01(q) - Applicable - Combustion turbines are subject to NSPS subpart GG; Duct burners are subject to NSPS subpart Db; Auxiliary boiler is subject to NSPS subpart Dc
- 607.01(z) - Applicable; EU01 & EU02 are designated as phase II affected units (Acid rain program under Title IV of the Clean Air Act)
- Env-A 618 *Additional Requirements in Non-Attainment Areas and the New Hampshire Portion of the Northeast Transport Region* - Applicable; Pursuant to PSD Permit# 044-121NH10, NEL was required to obtain NOx emission offsets in the ratio of 1.2:1
- Env-A 619 Prevention of Significant Deterioration - Applicable; PSD Permit# 044-121NH10 was issued on April 26, 1999. NEL is a major source for carbon monoxide (> 250 tpy)

Env-A 609 Title V Operating Permits - Applicable

Env-A 700 *Permit Fee System* - Applicable; NEL has paid emission-based fees through 2009.

Env-A 800 *Testing & Monitoring Procedures* - Applicable

Env-A 802 *Compliance Stack Test Testing Requirements* - applicable
Env-A 803.02 *Compliance Stack Testing for NOx* - Since the facility operates a certified CEMS to measure NOx emissions, periodic stack testing is not required.
Env-A 803.04 *Gaseous Concentration Measurements for Small Boilers and Emergency Generators* - Applicable to Auxiliary boiler.
Env-A 806 *Sulfur Content Testing of gaseous fuels* - Applicable
Env-A 808 *Continuous Emission Monitoring* - Applicable

Env-A 900 *Owner/Operator Obligations* - Applicable

Env-A 1211 *NOx RACT* - Applicable

Env-A 1211.06 *Emissions Standards for Combustion Turbines* - Applicable to the combustion turbines; PSD limit of 2.5 ppmdv (for natural gas) is more stringent than the NOx RACT limit of 25 ppmdv

Env-A 1211.12 *Emission Standards for Auxiliary Boilers* - Applicable to the auxiliary boiler.

The auxiliary boiler was originally permitted under TP-B-0483 which was issued on December 4, 2001. This T/P included a NOx limit of 0.2 lb/MMBtu as per the NOx RACT rule that was effective at that time. Env-A 1211 was amended on October 31, 2002. The current rule (Env-A 1211.12(b) & Env-A 1211.05(b)) requires the Owner/Operator to perform annual efficiency test and adjust the combustion process of the boiler. Please note that as per the current rule Env-A 1211.12, NOx RACT limit of 0.2 lbs/MMBtu is applicable to auxiliary boilers with a heat input rate of at least 50 MMBtu/hr. The auxiliary

boiler at NEL is rated at 25.2 MMBtu/hr.

Env-A 1400 *Regulated Toxic Air Pollutants* - Applicable; Facility is in compliance[8].

Env-A 1600 *Fuel specifications* - Applicable

Env-A 2000 *Fuel burning devices* - Applicable

Env-A 3000 *Emissions Reduction Credits Trading Program* - Not applicable

Env-A 3100 *Discrete Emissions Reductions Trading Program* - Applicable;

Env-A 3200 *NOx Budget Trading Program* - Applicable

Env-A 3700 *NOx Emissions Reduction Fund for NOx-Emitting Generation Sources* - This rule is not applicable to sources which meet the definition of a NOx budget source.

Env-A 4600 *Carbon Dioxide Budget Trading Program* - Applicable

Federal Regulations

New Source Performance Standards

❖ NSPS Subpart GG *Standards of Performance for Stationary Gas Turbines* is applicable to the combustion turbines;

§60.333 *Standard for NOx* - NOx limit for the gas turbines (EU01 & EU02) is calculated using the following equation:

$$STD = 0.0075\ (14.4/Y) + F$$

where:

STD = allowable ISO corrected NOx emission concentration (% by volume at 15% oxygen and dry basis)

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of 40 CFR 60.332.

Please note that Subpart GG limit is applicable to the turbines at all times. This is calculated on a 4-hr rolling average. PSD limits (Table 5, Item #13 of the Title V permit) apply at all times except during startup, shutdown and combustion turbine tuning. PSD limits are more stringent during normal operation. NEL uses CEMS to show compliance with the NOx emission limits.

§60.333 *Standard for SO_2* - Sulfur content of the fuel is limited to 0.8% by weight (8000 ppmw);

Please see DES' letter dated January 13, 2003 approving NEL's Custom Fuel Monitoring Schedule:

i. While firing pipeline natural gas, NEL is not required to monitor fuel nitrogen so long as the CEMS is used to monitor NOx emissions. In addition, NEL is not required to monitor the water-to fuel ratio during distillate fuel oil firing.

ii. NEL may use purchase contract, tariff sheet or transportation contract to show compliance with the gaseous fuel sulfur limit.

iii. NEL may use vendor analyses to satisfy the fuel oil sulfur monitoring requirements of subpart GG.

The above fuel sulfur monitoring requirements are included in Items 1 & 2 of Table 6 of the Title V permit.

- Since NEL uses Part 75 certified NOx CEMS to monitor NOx emissions, NEL is not required to monitor water-to-fuel ratio during distillate oil firing.
- Fuel sulfur content - PSD permit limit of 0.0015%[9] (by weight) is more stringent than the Subpart GG limit of 0.8% (by weight)

[8] Ammonia is emitted from the combustion turbines (i.e., Ammonia which does not react with NOx in the SCR). Please see modeling memo dated April 19, 2006. Dispersion modeling method was used to verify compliance with Env-A 1400.

[9] TP-B-0526 -- The sulfur content of distillate oil combusted in the combustion turbines shall be limited to 0.0015% by weight. As of December 12, 2006 (which is the issuance date for TP-B-0526), NEL shall only receive distillate oil that complies with the transportation grade sulfur limit of 0.0015 percent by weight. NEL 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).

- NSPS Subpart Db *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (> 100 MMBtu/hr)* is applicable to the duct burners. The only applicable standard is a NOx limit of 0.2 lb/MMBtu. Compliance with this limit was demonstrated during the stack conducted in September 2002.
- NSPS Subpart Dc *Standards of Performance for Stationary Gas Turbines Industrial-Commercial-Institutional Steam Generating Units (< 100 MMBtu/hr)* is applicable to the auxiliary boiler.
- NSPS Subpart Kb *New Source Performance Standards for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984* is **not** applicable to 1,000,000 gallon fuel oil storage tank. Vapor pressure of the fuel oil is less than 3.5 kPa.

National Emission Standards for Hazardous Air Pollutants

NESHAP Not applicable;

NEL is a major source for HAPs based on the potential to emit formaldehyde. This emission rate[10] is based on AP-42 Chapter 3.1 *Combustion Turbines*, Table 3.1-3 *Emission Factors for HAPs from Natural Gas-fired Stationary Gas Turbines*.

- 40 CFR 63, Subpart Q for *Industrial Process Cooling Towers* is not applicable to NEL because the facility does not use any chromium based water treatment chemicals.
- 40 CFR 63, Subpart YYYY for *Stationary Combustion Turbines* is not applicable to the facility. As per 40 CFR 63.6090(a)(1), turbines at this facility are existing, *i.e*., construction commenced on or before January 14, 2003, and in accordance with 40 CFR 63.6090(b)(4), these turbines do not have to meet the requirements of this subpart and of subpart A. No initial notification is necessary either.
- 40 CFR 63, Subpart ZZZZ, *National Emission Standards for Stationary Reciprocating Internal Combustion Engines* - N/A

New Source Review

When the facility was originally built, it was subject to New Source Review. PSD permit 044-121NH10 was issued on April 26, 1999. This permit established limits for PM_{10}, SO_2, NOx, CO, VOCs, Opacity and Ammonia. This permit also established maximum sulfur content limits for natural gas and oil which are more stringent than Env-A 1600 and NSPS Subpart GG. The PSD permit also required NEL to obtain offsets for NOx emissions in the ratio of 1.2 to 1.0. NEL meets its New Source Review offset requirement each year by surrendering a combination of Discrete Emissions Reductions (DERs) under regulation Env-A 3100 and seasonal NOx Budget allowances under Env-A 3200.

40 CFR 64 Compliance Assurance Monitoring[11] - Not applicable

- Compliance Assurance Monitoring (CAM) rule applies to Title V sources that operate emission units with pre-controlled potential emissions at or above the major source thresholds that rely on control devices to comply with applicable requirements. The purpose of CAM is to provide a reasonable assurance of compliance with the applicable requirements and emission standards. CAM rule establishes criteria for monitoring, record keeping and reporting that should be conducted by the facility to provide a reasonable assurance of compliance with the emission limits and standards.
- Pre-controlled emissions of NOx from each combustion turbine are greater than 100 tpy. Selective catalytic reduction system is used to control NOx emissions[12].from each CT. NOx emissions are continuously monitored by a certified monitor. CAM rule is not applicable to the NOx emissions from the combustion turbines based on the exemption provided in 40 CFR 64.2(b)(1)(vi).
- CO, SO_2 and PM_{10} emissions from the combustion turbines are also greater than 100 tpy. NEL does not operate any pollution control device to control the emissions of CO, PM_{10} and SO_2. CAM is not applicable to these three pollutants.

40 CFR 70, Title V - Applicable; NEL is major for PM_{10}, SO_2, NOx and CO

40 CFR 72 Acid Rain Program - Applicable; both the combustion turbines at NEL are designated as Phase II affected units

40 CFR 73 SO_2 Allowance System - Applicable

[10] Formaldehyde emission rate = 7.1e-04 lb/MMBtu x 2115 MMBtu/hr (LHV) x 2 turbines = 3 lb/hr & 13.15 tpy.

[11] CAM applicability criteria is specified in 40 CFR 64.2(a)

[12] Water injection system in conjunction with SCR - for distillate oil combustion

40 CFR 74 SO_2 Opt-ins - Not applicable

40 CFR 75 Continuous Emission Monitoring - Applicable

40 CFR 76 Acid Rain NOx Emission Reduction Program - Not applicable because NEL does not operate any coal-fired utility units

40 CFR 77 Excess Emissions - Applicable

40 CFR 78 Appeal Procedures for Acid Rain Program - Applicable

Section 112(r) Accidental Release Program - Applicable to the facility
NEL stores anhydrous ammonia in quantities above the level specified in 40 CFR 68, Section 112(r). NEL is required to operate the facility in accordance with the risk management plan.

4/13/10

As per NEL's request dated April 9, 2010, Table 5, Item #20 of the Title V Permit was amended to reflect Newington Energy's ability to switch fuels in the combustion turbines (EU01 & EU02) above 60% load.

Amended condition:

20.	Combustion turbine fuel transitions shall be defined as the period of time from the reduction of load below 60% load on one fuel , or the introduction of the other fuel, whichever occurs first, 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.	EU01 & EU02	TP-B-0526

ATTACHMENT A

ACID RAIN PROGRAM

In accordance with 40 CFR 72, both the combustion turbines are designated as Phase II affected units. Phase II means the acid rain program beginning January 1, 2000 and continuing into the future thereafter. Phase II affected unit means any affected unit that is subject to an acid rain emissions reduction requirement or an acid rain emissions limitation. Acid rain emissions limitation (for the purpose of SO_2) means the basic Phase II allowance allocations authorized to be allocated to an affected unit for use in a calendar year. DES issued Acid Rain permit TV-AR-005 on July 19, 2001. Under this permit, NEL was allocated zero allowances for SO_2. That means, NEL is required to acquire SO_2 allowances in the amount of one allowance for each ton of SO_2 emitted in accordance with 40 CFR 72.

40 CFR 75, *Continuous Emission Monitoring* is applicable to each affected unit subject to Acid Rain emission limitations for SO_2 or NOx[13]. Part 75 established requirements for monitoring, recordkeeping and reporting of SO_2, NOx and CO_2 emissions, volumetric flow and opacity data from the affected units.

40 CFR 75 - Continuous Emission Monitoring for Acid Rain Sources		
40 CFR 75, Subpart B - Monitoring Provisions	1. Requires Owner or Operator to measure Opacity, SO_2, NOx and CO_2 emissions.	40 CFR 75.10(a), (b), (c), (d), (f) & (g).
	2. SO_2 - Either install a CEMS or use App. D of Part 75 to calculate SO_2 emissions. NEL uses App. D to calculate SO_2 emissions.	40 CFR 75.11(d)
	3. NOx - Install CEMS to measure NOx. GRE operates a CEMS to measure NOx emissions.	40 CFR 75.12(c)
	4. CO_2 - Either install a CEMS or use App. G of Part 75 to estimate CO_2 emissions. NEL uses App. G to calculate CO_2 emissions.	40 CFR 75.13(b)
	5. Opacity - Continuous opacity monitoring system is not required for gas-fired units[14] pursuant to 40 CFR 75. Based on actual fuel oil usage during the last three years (2005-2007), both the combustion turbines qualify as gas fired units. Pursuant to 40 CFR 75.14(c) *Specific Provisions for Monitoring Opacity*, whenever a unit previously categorized as a gas-fired unit is recategorized as another type of unit by changing its fuel mix, the Owner or Operator shall install, operate and certify a COMS by December 31 of the following calendar year.	40 CFR 75.14(c)
	6. Heat input rate - The Owner or Operator is required to determine the heat input rate (in MMBtu/hr) for every hour following the procedures in Appendix F.	40 CFR 75.10(c)
40 CFR 75, Subpart C - Operation & Maintenance Requirements	Specifies procedures for: 1. Initial certification and recertification of CEMS.	40 CFR 75.20(a), (b), (c) & 75.22
	2. Quality assurance and quality control requirements for CEMS.	40 CFR 75.21(a), (c), (d) & (e)
	3. Out-of-control periods.	40 CFR 75.21(e)(2) & 75.24
40 CFR 75, Subpart D - Missing Data Substitution Procedures	This subpart provides missing data substitution procedures that should be followed whenever valid data is not collected by NOx CEMS	40 CFR 75.30, 75.31, 75.32, 75.33, 75.34, 75.36

[13] Since the turbines at NEL are not coal fired, there are no applicable acid rain NOx emission limits.

[14] Gas fired unit is defined in 40 CFR 72.2 as follows: Gas fired means the combustion of natural gas or other gaseous fuel (including coal-derived gaseous fuel) for at least 90% of the unit's average annual heat input during the previous three calendar years and for at least 85% of the annual heat input in each of those calendar years; and fuel oil, for the remaining heat input, if any.

40 CFR 75 - Continuous Emission Monitoring for Acid Rain Sources		
40 CFR 75, Subpart E - Alternative Monitoring Systems	Not applicable to NEL	
40 CFR 75, Subpart F - Recordkeeping Requirements	This subpart specifies the following recordkeeping requirements: 1. Monitoring plans - Electronic and hardcopy	40 CFR 75.53(a), (e) & (f)
	2. General recordkeeping requirements for operating parameters, emission rates and missing data.	40 CFR 75.57(a), (b), (c), (d), (e) & (h) & 75.58
	3. Certification & QA/QC records	40 CFR 75.59
40 CFR 75, Subpart G - Reporting Requirements	This subpart specifies reporting requirements. The designated representative shall submit:	40 CFR 75.60
	1. Notifications	40 CFR 75.61
	2. CEMS initial certification and recertification reports	40 CFR 75.63
	3. Monitoring plans	40 CFR 75.62
	4. Electronic quarterly reports	40 CFR 75.64
	5. Annual RATA reports	40 CFR 75.60(a)(6)
40 CFR 75, Subpart H - NOx Mass Emission Provision	Requirements for units that are subject to State NOx mass reduction program (i.e., Env-A 3700)	40 CFR 75.70, 75.71(c), 75.72, 75.73, 75.74 & 75.75
40 CFR 75, Subpart I - Mercury Mass Emission Provisions	Not applicable	
40 CFR 75, Appendix A - Specifications and Test Procedures	Applicable	
40 CFR 75, Appendix B - QA/QC Procedures	Applicable	
40 CFR 75, Appendix C - Missing Data Estimation Procedures	Section 2 is applicable to NOx lb/MMBtu missing data substitution.	
40 CFR 75, Appendix D - Optional SO_2 Emissions Data Protocol for Gas-fired Units	Applicable; NEL uses these procedures to calculate SO_2 emissions since it does not operate a CEMS for SO_2. NEL uses an emission factor of 0.0006 lb/MMBtu from Table D-5 of Appendix D to calculate SO_2.	
40 CFR 75, Appendix E - Optional NOx Emissions Estimation Protocol for Gas-fired Peaking Units	Not applicable because the gas fired units at NEL are not considered “peaking” units. Please see the definition of a peaking unit in 40 CFR 72.2.	
40 CFR 75, Appendix F - Conversion Procedures	Applicable	
40 CFR 75, Appendix G - Determination of CO_2 Emissions	Applicable	