VERMONT AGENCY OF NATURAL RESOURCES
Department of Environmental Conservation
Air Pollution Control Division

TECHNICAL SUPPORT DOCUMENT FOR

TITLE V AIR POLLUTION CONTROL PERMIT TO CONSTRUCT AND OPERATE AND ACID RAIN PHASE II PERMIT

#AOP-07-020

April 21, 2008

Joseph C. McNeil Electric Generating Station, Burlington, VT

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Air Pollution Control Division

This Technical Support Document details the Agency of Natural Resources, Department of Environmental Conservation, Air Pollution Control Division review for the Air Pollution Control Permit to Construct and is intended to provide additional technical information, discussion and clarification in support of the Permit. It is not intended to provide a comprehensive review of the Facility or permit process or duplicate the information contained in the Permit.

Facility:
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Electric Generating Station
111 Intervale Road
Burlington, VT 05401

Facility / Applicant Contact Person:
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1.0 INTRODUCTION

Burlington Electric Department (hereinafter "The Permittee") owns and operates the Joseph C. McNeil Generating Station (also referred to herein as "Facility") at 111 Intervale Road, Burlington, Vermont. The Permittee has proposed to modify the Facility by installing and operating a selective catalytic reduction system on the main boiler in order to reduce the NO_X emissions so the facility can qualify for the Renewable Energy Credit (REC) market. If necessary, the Permittee may also install a carbon monoxide (CO) catalyst to reduce the CO emissions so they are in line with the requirements for the REC market. This permit is also the renewal of the existing operating permit (AOP-01-057).

The allowable emissions for the Facility are summarized below:

Allowable Air Contaminant Emissions (tons/year)[1]					
PM/PM10	***SO2***	***NOx***	***CO***	***VOC***	***Total HAPs*** [2]
42	44.6	>100	1469	<50	<10/25

[1] PM/PM10 - particulate matter, SO2 - sulfur dioxide, NOx - oxides of nitrogen, CO - carbon monoxide, HAPs - hazardous air pollutants.
[2] Emissions of individual HAPs each < 10 tpy and emissions of total HAPs combined <25 tpy.

2.0 FACILITY DESCRIPTION AND LOCATION

2.1 Facility Locations and Surrounding Area

Burlington Electric Department operates the multi-fuel power plant located at 111 Intervale Road, Burlington, Vermont. The area surrounding the Facility is primarily industrial and commercial, with residences nearby.

2.2 Facility Description

The Facility is a electric power generating station listed under the Standard Industrial Classification ("SIC") Code 4911, Electric Services. The regulated sources of air contaminant emissions at the Facility are the multi-fuel boiler, waste oil furnace and auxiliary boiler.

2.2.1 Description of Existing Equipment

See Table 2-1 for a listing of existing equipment at the Facility.

Table 2-1: Existing Facility Equipment	
Main Boiler: Zurn, 1981 **Total Gas Ports: 6**	Wood: 750 MMBtu/hr (85 ton/hr) Oil Burners (3): 27 gal/min Total Capacity <250MMBtu/hr Natural Gas Burners (6): 660 MMBtu/hr total capacity Low NO_x burners: FGR
Auxilliary Water Tube Boiler: Cleaver Brooks 1983	4 MMBtu/hr (Oil 30 gph, Natural Gas 4,000 scf/hr)
Waste Oil Furnace, 2003	0.28 MMBtu/hr
Distillate Fuel Oil Storage Tank, Fixed Roof, Top Vent, 1983	300,000 gallon capacity
Distillate Fuel Oil Tank	6,000 gallon capacity

Table 2-2: Stack Data	
Main Stack	Height: 257 ft Diameter: 10 ft Max. Flow Rate: 285,000 acfm (wood) 32,000 acfm (oil) 200,000 acfm (natural gas)
Auxiliary Boiler Stack	Height: 128 ft. Diameter: 12 in. Max. Flow Rate: 1,500 acfm

2.2.2 Description of Existing Air Pollution Control Equipment

See Table 2-3 for a listing of existing equipment at the Facility.

Table 2-3: Existing Air Pollution Control Equipment & Techniques	
Multiclone	Manufacturer: General Electric Environmental Services Model 4X6B56CG37 Pressure Drop: 5” water Inlet Temperature: 315^0F Dimensions: 4.6 sq. ft. inlet area per tube, 56” diameter Number of Cyclones: 18
ESP (9 Field)	Manufacturer: GEESI Model: BA.2X52K4443-6.4 Type of Unit:: Plate and weighted wire Cleaning Method: Rapping Inlet Temperature: 300^0F Collecting surface area: 280,800 ft^2 Air Flow Rate: 300,000 cfm Corona Power: 3,000 w/Kacfm

2.3 Description of Compliance Monitoring Devices

The Facility is equipped with continuous emission monitoring devices (CEMS) which measure the emission of NO_x, CO, and either O_2 or CO_2 from the Main Boiler to the ambient air. In addition, the Facility also operates and maintains a continuous opacity monitoring system (COMS) which measures the opacity of the exhaust gas from the Main Boiler.

2.4 Proposed Modifications to Facility

The Permittee has proposed to modify the Facility's main boiler by installing and operating "tail end" selective catalytic reduction NO_X control technology with an (optional) CO catalyst, so the Facility may be eligible for Connecticut and Massachusetts Class 1 Renewable Energy Credits.

The NO_X control system will be retrofitted to the existing plant between the ESP and the stack. To raise and control the exhaust gas temperature entering the control system, supplemental burners will be installed. The maximum heat rate of the burners will not be more than 20 MMBtu/hr. The burners can be fueled with either No. 2 fuel oil or natural gas. Natural gas is expected to be the primary fuel utilized for these supplemental burners.

2.5 Identification of Sources with Insignificant or Negligible Emissions

Although not required for determining applicability with Subchapter X, quantifiable emissions from "insignificant activities" must be included for the purposes of establishing whether or not a source is subject to other air pollution control requirements, including, but not limited to: reasonably available control technology, major source status, and Title V operating permit applicability.

Additionally, guidance provided by the U.S. EPA (entitled "White Paper for Streamlined Development of Part 70 Permit Applications") lists activities which are considered as "trivial" sources of air contaminants, and may be presumptively omitted from operating permit applications.

Table 2-4 lists activities at the Facility which were considered negligible or exempt sources of contaminant emissions, and therefore were not considered as emission sources as part of the Permit.

Table 2-4: Negligible Sources of Contaminant Emissions	
Cooling Tower Emissions	Induced Draft, Counter Flow Design
Distillate Fuel Tank	For 300,000 and 6,000 gallons fuel tanks.

It should be noted that a process or piece of equipment which is considered a "negligible activity" does not relieve the owner or operator from the responsibility of complying with any applicable requirements associated with said process or equipment.

2.6 Proposed Limitations

The Permittee has proposed to limit the emissions of ammonia, due to ammonia slip from the SCR system, to 20 ppmv. The Permittee also proposed that the fuel neutral 39 ton/yr SO_2 limit for the main boiler to include the SO_2 emissions resulting from the use of supplemental fuel required for operating the SCR system.

3.0 QUANTIFICATION OF POLLUTANTS

The quantification of emissions from a stationary source is necessary in order to establish the regulatory review process necessary for the operating permit application and to determine applicability with various air pollution control requirements. These determinations are normally based upon allowable emissions. Allowable emission is defined as the emission rate calculated using the maximum rated capacity of the source and, if applicable, either: (a) the applicable emission standard contained in the *Regulations*, if any, or (b) the emission rate or design, operational or equipment standard specified in any order or agreement issued under the *Regulations* that is state and federally enforceable. An applicant may impose in its application an emission rate or design, or an operational or equipment limitation which may be incorporated in the Permit to restrict operation to a lower level. Such limitations may include fuel restrictions or production limits.

3.1 Estimating Potential Emissions of Criteria Pollutants from the Existing Stationary Source

Table 3-1: MAIN BOILER: Wood Combustion

750 MMBtu/hr 8760 hrs/yr	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	--	--	Proposed Cap (Fuel Neutral)	39
NO_x	493	Tons/year	Fuel Neutral Limit: RACT, VAPCD, 2003	493
PM	9.7	Lbs/hr	1989 Ambient Air Quality Modeling Study	42
CO	335	Lbs/hr		1467
VOC	0.0041	Lbs/MMBtu	Facility emissions testing on July 13, 2005	13.5
HAPs	0.0043	Lbs/MMBtu	AP-42 Wood Residue Combusted in Boilers, Tables 1.6-3 &4(7/01) and Facility emissions testing	14.1 total HAP

Table 3-2: MAIN BOILER: Distillate Oil Combustion				
250 MMBtu/hr 0.30 % S Max. Potential fuel usage: 15.6 x 10^6 gal	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	--		Proposed Cap (Fuel Neutral)	39
NO_x	493	Tons/year	Fuel Neutral Limit RACT, VAPCD, 2003	493
PM	2	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-1(9/98)	15.6
CO	5	Lbs/1000 gal		39
VOC	0.2	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-3(9/98)	1.6
HAPs	0.0622	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Tables 1.3-8,9,10 &11(9/98)	0.5

Table 3-3: MAIN BOILER: Natural Gas Combustion				
660 MMBtu/hr Max. Potential Fuel Usage*: 5256 x 10^6 scf/yr	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons//year
SO_2	0.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	1.6
NO_x	0.13	Lb/MMBtu	MSER, VAPCD 9/15/89	375
PM	7.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	20
CO	84	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	220
VOC	5.5	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	14
HAPs	1.93	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-3(9/98)	5

* 660 MMBtu/hr x scf/0.0011 MMBtu x 8760 hr/yr = 5256 x 10^6 scf
Worst Case (Wood, Distillate and Natural Gas Fuels)

Table 3-4: Main Boiler Allowable Emissions, tons per year – Worst Case Allowable Emissions for Main Boiler					
SO_2	NO_x	PM	CO	VOC	HAPs
39	493	42	1467	<50	<10/25

Table 3-5: AUXILIARY BOILER: Distillate Oil				
4 MMBtu/hr @ 0.14 MMBtu/gal for 8760 hr/yr, 250,285 gal/yr) Sulfur Content: 0.3%max.	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	142S	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-1(9/98)	5.3
NO_x	20	Lbs/1000 gal		2.5
PM	2	Lbs/1000 gal		0.25
CO	5	Lbs/1000 gal		0.63
VOC	0.2	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-3(9/98)	0.03
HAPs	0.0622	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Tables 1.3-8,9,10 &11(9/98)	0.008

Table 3-6: AUXILIARY BOILER: Natural Gas				
4 MMBtu/hr @ 0.0011 MMBtu/scf, 8760 hr/yr, Max usage: 31.8 x 10^6 scf/yr)	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	0.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	0.01
NO_x	100	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	1.6
PM	7.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	0.12
CO	84	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	1.3
VOC	5.5	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	0.08

Table 3-7: Auxiliary Boiler Allowable Emissions, tons per year Worst Case Emissions: Auxiliary Boiler: Distillate Fuel Oil and Natural Gas					
SO_2	NO_x	PM	CO	VOC	HAPs
5.3	2.5	0.25	1.3	0.03	0.008

Table 3-8: Waste Oil Furnace				
0.28 MMBtu/hr @0.15 MMBtu/hr, for 8760 hr/yr, Max. fuel usage: 16,350 gal/yr Max. Sulfur: 0.3%	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	142S	Lb/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-1(9/98)	0.34
NO_x	20	Lb/1000 gal		0.16
PM	2	Lb/1000 gal		0.016
CO	5	Lb/1000 gal		0.04
VOC	0.34	Lb/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-3(9/98)	0.003
HAPs	0.0622	Lb/1000 gal	AP-42, Fuel Oil Combustion, Tables 1.3-8,9,10 & 11(9/98)	0.0005

Table 3-9: Total Facility Allowable Emissions, tons per year						
	SO_2	NO_x	PM	CO	VOC	HAPs
Main Boiler	39	493	42	1467	<50	<10/25
Auxiliary Boiler	5.3	2.5	0.25	1.3	0.03	0.008
Waste Oil Furnace	0.34	0.16	0.016	0.4	0.003	0.0005
Total	44.6	495.6	42	1469	<50	<10/25

As summarized in Table 3-9 above, the Facility has allowable emissions of all air contaminants in the aggregate of ten (10) or more tons per year. The Facility is therefore subject to Subchapter X of the Regulations and is designated as a Subchapter X Major Source. The Facility also has allowable emissions of at least one contaminant of fifty (50) or more tons per year which classifies the source as a "Title V Subject Source" and therefore is subject to the federal operating permit requirements of 40 C.F.R. Part 70 or 71.

3.2 Estimating Actual Emissions of Hazardous Air Contaminants from the Existing Stationary Source.

The wood boiler (constructed prior to January 1, 1993) and combustion of natural gas and virgin fuel oil are exempt from this regulation per 5-261(1)(b)(2). So, emissions of HACs from the combustion of wood, fuel oil or natural gas in the main boiler have not been estimated.

The proposed SCR system is anticipated to have emissions of ammonia due to ammonia slip. The SCR system will be required to not exceed 20 ppmv of ammonia. The following is an estimate of the maximum potential ammonia emissions due to the operation of the SCR system; the actual emissions should be less.

Basis:
Flue gas flow rate: 240,000 scfmw (wet)
Flue gas moisture content: 21%
Ammonia concentration: 20 ppmvd (dry)
Hours of operation: 8760 hrs/yr

(240,000 scfmw) * ((100%-21%)/100%) * (20 scf NH_3/1,000,000 scf exhaust) * (14.7 psia/((10.73 psia-scf/lbmole-^oR)*(528 ^oR)) * (17 lbs NH_3/lbmole NH_3) * 60 min/hr) * (8 hours)

= 80.2 lb/8-hr of ammonia emissions.

Table 3-10 summarizes the estimated emissions of HACs:

Table 3-10 Quantification of HAC Emissions

Hazardous Air Contaminant	CAS#	Toxic Category	Emission Rate (lb/8-hrs)	Action Level (lb/8-hrs)
Ammonia	7664-41-7	2	80.2	8.3

3.3 Designation of Proposed Modification for the Permit to Construct

The designation of the proposed modification is determined by the designation of the existing Facility and the allowable emissions associated with the proposed modification. The existing Facility, before construction or installation of the proposed modification, is designated as a major stationary source of air contaminants, as defined in §5-101 of the Regulations, is designated as a major modification and is subject to review under §5-502 of the Regulations. The modification's allowable emissions are calculated according to the following procedure.

Step a: Calculate the allowable emissions for each new piece of equipment or process being added.

The SCR will be equipped with supplemental burners with a total maximum rate heat input of 20 MMBtu/hr. The burners will be permitted to burn either natural gas or No. 2 fuel oil.

Maximum annual natural gas usage:
(20 MMBtu/hr) / (0.0011 MMBtu/scf) * (1 MMscf/10^6 scf) * (8760 hr/yr) = 159.3

Maximum annual oil usage:
(20 MMBtu/hr) * (0.14 MMBtu/gallon) * (8760 hr/yr) = 1,251,429 gallons

Table 3-11: SCR Supplemental Burners: Natural Gas				
159.3 MMCF/yr	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	0.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	0.05
NO_x	100	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	8.0
PM	7.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	0.6
CO	84	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	6.7
VOC	5.5	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	0.4

Table 3-12: SCR Supplemental Burners: Distillate Oil				
1,251,429 gallon/yr	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	142S	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-1(9/98)	26.7
NO_x	20	Lbs/1000 gal		12.5
PM	2	Lbs/1000 gal		1.3
CO	5	Lbs/1000 gal		3.1
VOC	0.2	Lbs/1000 gal	AP-42, Fuel Oil Combustion, Table 1.3-3(9/98)	0.1

The SCR is also expected to have emissions due to ammonia slip. Based on the emission rate shown in Table 3-10 the following in the maximum annual emissions of ammonia:

(80.2 lb/8-hr) * (8760 hr/yr) * (1 ton/2000 lbs) = 43.9 ton/yr ammonia

Step b: Calculate the allowable emissions for all existing processes that are affected by the modification.

The operation of the SCR will not affect the allowable emissions of any of the existing processes at the facility.

Step c: Calculate the actual emissions from all existing processes that are affected by the modification (i.e., that were included in Step b) that were installed prior to 1979 or have already been reviewed as being major under §5-502 of the Regulations.

Not applicable

Step d: Calculate the allowable emissions from all other equipment or processes at the facility modified since 1979 that have not been reviewed as being major in the past.

Permit #AP-89-010a issued on June 9, 1995 approved the installation of an experimental wood gasifier as a minor modification. With the issuance of Permit AOP-07-020, this experimental gasifier is no longer permitted to operate and its allowable emissions do not need to be considered here.

Permit #AP-98-010 issued on September 15, 1989 approved the installation of natural gas burners. With an annual natural gas fuel limit of 1.2 billion cubic feet/year this was reviewed as a major modification for NO_X, CO and PM. So the allowable emissions for VOCs and SO_2 need to be included in the review of the SCR installation.

Table 3-13: Main Boiler: Natural Gas

1,200 MMCF/yr	Emission Factor			Allowable Emissions
	Factor	Units	Source	Tons/year
SO_2	0.6	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-1(9/98)	0.36
VOC	5.5	Lb/10^6 scf	AP-42, Natural Gas Combustion, Table 1.4-2(9/98)	3.3

Step e: Calculate the size of the modification on a pollutant-by-pollutant basis using the following formula:

Results of [step a + step b – step c + step d] = size of modification

Table 3-14: Allowable Emissions from Modifications (tons/year)

	PM/PM_{10}	**SO_2**	**NO_x**	**CO**	**VOCs**
Step a (the higher of oil or natural gas)	1.3	26.7	12.5	3.1	0.1
Step b	--	--	--	--	--
Step c	--	--	--	--	--
Step d	--	0.4	--	--	3.3
Step e: (a+b-c+d)	1.3	27.1	12.5	3.1	3.4
Significance Level	25/15	40	40	50	50

The proposed modification's allowable emissions are summarized in Table 3-14. The proposed modification's allowable emissions are estimated to result in an emissions

increase less than major levels for each air contaminant. Therefore, the proposed modification is designated as a non-major modification.

4.0 DISCUSSION OF SELECT APPLICABLE AND NON-APPLICABLE REQUIREMENTS

The Agency will assess compliance with these regulations during any inspections of the Facility. The inspections will include confirmation of the proper operation and maintenance of equipment and air pollution control devices, visual observations of emission points, and review of any records required by the Permit.

4.1 Vermont Air Pollution Control Regulations and Statutes

§5-201 and §5-202 - Open Burning Prohibited and Permissible Opening Burning
Open burning of materials is prohibited except in conformance with the requirements of this section.

§5-211(2) - Prohibition of Visible Air Contaminants - Installations constructed subsequent to April 30, 1970
This emission standard applies to all stacks and vents at the facility.

§5-221(1) - Prohibition of Potentially Polluting Materials in Fuel; Sulfur Limitation in Fuel
This prohibition applies to all stationary fuel burning equipment used on-site including the Main Boiler, Auxiliary Boiler and Waste Oil Furnace. Based on the application submittal, the applicant is expected to comply with this regulation based on the use of natural gas and distillate oil. Natural gas and distillate oil, by their official fuel specification definition, comply with this requirement.

§5-221(2) - Prohibition of Potentially Polluting Materials in Fuel; Waste Oil
The use of waste oil as a fuel is prohibited except in conformance with the requirements of this section. Based on the application submittal and information available to the Agency, the Facility does burn waste oil in a 0.28 MMBtu/hr waste oil furnace and is therefore currently subject to this regulation.

§5-231(3)(a) - Prohibition of Particulate Matter; Combustion Contaminants
Based on the application submitted and information available to the Agency, this Facility currently has applicable fuel burning equipment subject to this regulation. The allowable particulate emissions from the subject equipment are shown in Table 4-1.

Table 4-1: Equipment Subject to §5-231(3)

Equipment ID	*Size/Capacity MMBtu/hr*	*Emission Standard, lbs/MMBtu*	*Allowable Emissions, lbs/hr*
Auxiliary Boiler	4	0.5	2.0
Waste Oil Furnace	0.28	0.5	0.14

§5-231(3)(b) - Prohibition of Particulate Matter; Combustion Contaminants
Based on the application submitted and information available to the Agency, this Facility currently has applicable fuel burning equipment subject to this regulation. However, the combustion of wood chips in the Main Boiler is subject to the more stringent MSER emission rate of 0.007 gr/dscf corrected t o12% CO_2.

§5-231(4) - Prohibition of Particulate Matter; Fugitive Particulate Matter
This section requires the use of fugitive PM control equipment on all process operations and the application of reasonable precautions to prevent PM from becoming airborne during the handling, transportation, and storage of materials, or use of roads. This requirement applies to the entire Facility, and the Facility is therefore expected to comply with the fugitive emission limitations of this section.

§5-241(1) & (2) - Prohibition of Nuisance and Odor
This requirement applies to the entire Facility and prohibits the discharge of air contaminants that would be a nuisance to the public or the discharge of objectionable odors beyond the property-line of the Facility.

§5-251 - Control of Nitrogen Oxide Emissions
Based on the application submittal and information available to the Agency, this Facility is subject to this regulation. However the MSER emission rate is more stringent.

§5-252 - Control of Sulfur Dioxide Emissions. Based on the application submittal and information available to the Agency, this Facility currently has no applicable fuel burning equipment subject to this regulation.

§5-261 - Control of Hazardous Air Contaminants
See Section 7.0 below.

§5-502(3) - Most Stringent Emission Rate. As part of obtaining approval for the original installation of the main boiler and the major modification involving the addition of natural gas burners in 1989, the Agency required the Permittee to achieve the MSER pursuant to §5-502(3) of the Regulations.

4.2 Federal Air Pollution Control Regulations and the Clean Air Act

<u>40 C.F.R. Part 60 Subpart Da</u> – Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978

"The affected facility to which this Subpart applies is each electric utility steam generating unit that is capable of combusting more than 73 megawatts (250 MMBtu/hr) heat input of fossil fuel either alone or in combination with any other fuel for which construction or modification is commenced after September 18, 1978."

This regulation applies to combustion of oil and natural gas in the Main Boiler.

The regulation limits emissions of particulate matter, sulfur dioxide, nitrogen oxides and opacity, requires the installation and operation of continuous emission monitoring systems (CEMS) and imposes reporting and compliance determination procedures. See the Equivalency Determinations in the Permit for specific emission limits.

The McNeil Generating Station was not subject to this regulation as constructed because the fossil fuel burning capacity was less than 250 MMBtu/hr. The Main Boiler at the Facility become subject to this subpart following installation of natural gas burners in 1989. Additionally, the Facility is also subject to General Provisions of 40 CFR Part 60 Subpart A.

***40 C.F.R. Part 64* – Compliance Assurance Monitoring (CAM)**

CAM applies to the particulate emissions from the Main Boiler as the precontrol emissions exceed the major source threshold, the unit is subject to an emission limit or standard and a control device is used to achieve compliance.

***40 C.F.R. Part 60 Subpart Kb* – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984**

"(a) Except as provided in paragraph (b) of this section, the affected facility to which this subpart applies is each storage vessel with a capacity greater than or equal to 75 cubic meters (m3) (19,805 gallons) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984.
(b) This subpart does not apply to storage vessels with a capacity greater than or equal to 151 m3 storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equa to 75 m3 but less than 151 m3 storing a liquid with a maximum true vapor pressure less than 15.0 kPa."

The Permittee operates one storage tank with a capacity greater than 19,805 gallons, however the tank was installed prior to July 23, 1984 and the maximum true vapor pressure of No.2 fuel oil is less than 3.9 kPa. Consequently, the Permittee is not subject to this regulation at this time.

***40 C.F.R. Parts 72-78* – Acid Rain Program**

The Permittee is required to operate the Facility under a permit that includes the Acid Rain Program requirements. This section also requires that the Facility be equipped with a CEMS and meet additional recordkeeping and reporting requirements.

Section 112 of the Clean Air Act - National Emission Standards for Hazardous Air Pollutants (NESHAPs). NESHAPs are promulgated under 40 C.F.R. Part 61 and 63.

No promulgated NESHAPs in 40 *CFR* Part 61 or 63 currently are applicable to the Facility at this time. The Facility is not considered to be a major source of hazardous air pollutants.

5.0 CONTROL TECHNOLOGY REVIEW FOR MAJOR SOURCES AND MAJOR MODIFICATIONS

The Facility is not undergoing changes subject to new source review; therefore this section is not applicable.

6.0 AMBIENT AIR QUALITY IMPACT EVALUATION

For permit AP-89-010, issued September 15, 1989, an ambient air quality impact evaluation was performed. The objective of the dispersion modeling was to demonstrate compliance with the Vermont and National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. Since the facility change in 1989 was a Major Modification, the Facility was allowed only 25% of the remaining annual PSD increment.

MODEL RESULTS - Refined Modeling: Ambient Air Quality Standards - The applicant used ISCST to estimate the impact of SO_2, NO_2, and PM due to the proposed project. The results of the air quality impact evaluation are shown in Table 6-1. Model results show that emissions from the modifications will not exceed National Ambient Air Quality Standard.

Table 6-1: ISCST Maximum Concentration Results Compared to AAQS

Pollutant	Averaging Time	Modeled Emission Rate (g/s)[1]	Maximum Concentration ($\mu g/m^3$) [2]	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	Annual	1.9	0.5	17	17	80
	24- hour	12.6	63.1	68	131	365
	3-hour		141.9	141	283	1,300
CO	8-hour	42.2	184.1	6,954	7,138	10,000
	1-hour		263	13,566	13,829	40,000
NO_2	Annual	17.2	4.5	36	41	100
	1-hour	18.2	113.4	141	254	320

Table 6-1: ISCST Maximum Concentration Results Compared to AAQS						
Pollutant	**Averaging Time**	**Modeled Emission Rate (g/s)[1]**	**Maximum Concentration ($\mu g/m^3$) [2]**	**Background Concentration ($\mu g/m^3$)**	**Total Concentration ($\mu g/m^3$)**	**Standard ($\mu g/m^3$)**
PM_{10}	Annual	1.2	0.3	30	30	50
	24- hour		3.0	52	55	150
PM (TSP)	Annual		0.3	67	67	75
	24- hour		3.0 [3]	161	182	150

[1] g/s: emission rate of the pollutant in terms of grams of pollutant per second.
[2] $\mu g/m^3$: micrograms of pollutant per cubic meter of air.
[3] At the time this modeling was conducted, the existing 24-hour TSP background level of 161 $\mu g/m^3$ exceeded the secondary standard of 150 $\mu g/m^3$. The maximum impact from the Facility of 3.0 $\mu g/m^3$ (24-hour) was less than the significant impact level of 5.0 $\mu g/m^3$ (24-hour).

Prevention of Significant Deterioration - The results of the air quality impact evaluation performed using ISCST are shown in Tables 6-9. Model results demonstrated compliance with the PSD increments.

Table 6-2: ISCST Predicted PSD Increment Consumption April, 1989		
Pollutant	**PSD Increment Consumed ($\mu g/m^3$)**	**PSD Increment Available ($\mu g/m^3$)**
SO_2	0.3	5.0
NO_2	3.5	6.3
PM	0.2	4.7

7.0 HAZARDOUS AIR CONTAMINANTS & HAZARDOUS AIR POLLUTANTS

The emissions of hazardous air contaminants ("HACs") are regulated under to §5-261 of the Regulations. The Owner/Operator of a source must quantify its emissions of HACs regulated by this rule. Any Facility whose emission rate of a HAC exceeds its respective Action Level ("AL") is subject to the rule for the HAC, and the Owner/Operator must then demonstrate that the emissions of the HAC are minimized to the greatest extent practicable by achieving the Hazardous Most Stringent Emission Rate ("HMSER") for that HAC. If the emission rate of any HAC after achieving HMSER is still estimated to exceed its action level after achieving HMSER, an air quality impact evaluation may be required to further assess the ambient impacts for compliance with the Hazardous Ambient Air Standard ("HAAS") or Stationary Source Hazardous Air Impact Standard ("SSHAIS").

This facility has a permit condition limiting the emissions of HAPs to 10 ton/year of any single HAP and 25 tons/year of all HAPS combined, therefore the facility is not subject to the federal HAP standards. Note that ammonia is a Vermont HAC, but is not listed as a HAP by the US EPA.

As shown in Section 3, if the SCR system is installed and operated then the facility is expected to exceed the action level of ammonia and is therefore subject to §5-261.

7.1 HMSER Selection

If the emission of any HAC from all regulated sources at the Facility is estimated to exceed its AL, then the Facility is subject to the rule and the emissions must be reduced to achieve HMSER for that HAC.

HMSER has been determined to be an ammonia emission limit of 20 ppmdv @ 6% O_2 based on an 8-hr rolling average and the operation of an ammonia continuous emission monitor (CEM).

The annual potential emission of ammonia for this facility, as noted in Section 3.3 above, is 43.9 tons/year. As part of the Permittee's Act 248j petition, the Permittee assessed the potential concentration of ammonia in the ambient air. The US EPA's SCREEN3 model was used as well as scaling prior refined modeling results that were conducted for the facility. The modeling results projected the maximum impact concentration of ammonia to be two orders of magnitude lower than the Hazardous Ambient Air Standard. The Agency did not review this modeling analysis.

8.0 REASONABLY AVAILABLE CONTROL TECHNOLOGY

§5-1010 of the Regulations requires sources to install, maintain and use Reasonably Available Control Technology (RACT). RACT is defined in the Regulations as "devices, systems, process modifications or other apparatus or techniques designed to prevent or control emissions that are reasonably available, taking into account the social, environmental and economic impact of such controls, and alternative means of emission control". A RACT analysis typically reviews a range of emission reduction options, from the greatest reduction to the least (Top Down). RACT exists within a hierarchy of emission reduction acronyms. In descending order of emission reduction, these are: LAER, MSER, BACT, NSPS, RACT.

<u>Past RACT Review:</u>

On September 6, 2002 the Permittee submitted an Operating Permit RACT analysis for the pollutants NO_x and CO per Agency request. The RACT Analysis addressed the feasibility of various combustion modifications, cofiring and post combustions control techniques in achieving NO_x reductions during wood, oil and natural gas combustion in the Main Boiler. The report also examined the feasibility of oxidation catalysts for CO emission reductions. The report concluded that none of the various emission reduction techniques examined were appropriate RACT at that time.

For permit #AOP-01-057, issued on August 28, 2003, the Agency determined that RACT for NO_x to be performance of a pilot study to examine the impact of cofiring natural gas with wood on the NO_x emission rate in addition to more stringent NO_x emission rates for wood and oil combustion. The short term NO_x emission rate for wood and oil combustion was reduced from 0.249 lb/MMBtu to 0.23 lb/MMBtu. The Agency lowered the short term emission rate for wood and oil to more closely reflect the NO_x baseline emission rates presented in the RACT report. The Agency has also required the Permittee to report all NO_x emission that exceed 0.21 lbs/MMBtu on a quarterly basis. The limit was based on optimized operation of the boiler in its current configuration.

The long term NO_x emission rate was also modified to more closely reflect the baseline emissions of the facility. The RACT report states that the Main Boiler at the facility has been achieving an annual average NO_x emission rate of 0.15 lb/MMBtu. The Agency extrapolated the baseline emission rate of 0.15 lb/MMBtu for the Main Boiler heat input rating of 750 MMBtu/hr for 8760 hours per year resulting in a NO_x emission limit of 493 tons per rolling twelve month.

RACT for CO was reviewed and continued to be good combustion practices and a CO limit of 1500 ppmv (1 hour average).

During 2004, the Permittee investigated NO_X reduction by cofiring natural gas with wood. The correct term is ‘reburning’ and it involves the injection of unburned natural gas at appropriate exhaust temperatures to induce a chemical reaction between the methane and NO in an oxygen deficient environment. It was determined that the Facility’s existing equipment, configuration and controls are not appropriate for a reburning test.

<u>RACT Review for Permit #AOP-07-020:</u>

Since the time that the September 6, 2002 RACT analysis was prepared, there has been a development in post combustion technology for NO_X reduction for biomass boilers. The advancement utilizes heat exchangers to raise the temperature of the exhaust gas after the particulate matter control device so less additional fuel energy is necessary to raise the exhaust temperature necessary for selective catalytic reduction (SCR). This technology improves the economics of a traditional SCR by reducing the amount of fuel that is required to heat the exhaust gases to the proper reaction temperature for the SCR process.

One of the designs is called: Regenerative Selective Catalytic Reduction (RSCR). The RSCR technology is expected to achieve 70 to 80 % reduction in NO_X emissions which is better control when compared to SNCR. The supplier of the RSCR process, Babcock Power Environmental, Inc., has estimated the cost efficiency of their RSCR system for a typical 50 MW biomass plant at $5,030 per ton of NO_X removed. This cost reflects both the initial capital cost as well as the operating and maintenance costs.

Without additional economic incentives, the installation and operation of an SCR system is not RACT.

This improvement in NO_X reduction efficiency makes it possible for biomass fueled boilers to meet the low NO_X emission limits required for the Renewable Energy Credit (REC) markets in Massachusetts and Connecticut. A strong REC market impacts the economics of NO_X RACT. A compelling reason for an existing biomass fueled electric generating facility to install a NO_X reduction system is to qualify the electrical output of the facility for the REC market and to sell renewable energy credits. In the Petition of Burlington Electric Light Department for amending their certificate of public good (pursuant to Act 248j), they note that the costs associated with installing and operating a SCR system on their main boiler will be covered if they are able to sell generated Class 1 RECs for $20/REC for the first three years and $4/REC thereafter.

Permittee is proposing to install an SCR system at the Facility so they can qualify for the Class 1 Renewable Energy Credit market in Connecticut and possibly Massachusetts. Upon qualifying for any of the REC markets, RACT for the main boiler at the Facility will be the operation of the NO_X SCR system and a NO_X emission limit of 0.075 lb/MMBtu based on a quarterly average.

If the Permittee successfully qualifies for the REC market but then elects to no longer participate in the REC market, they may file an amendment application for reconsideration of this NO_X RACT determination. The Permittee will need to demonstrate that the continued operation and maintenance cost, but not the initial capital costs are excessive for RACT.

Should the Permittee decide not to install the SCR system, then NO_X RACT for the Facility, without the NO_X SCR system, will continue to be good combustion control with the same limits from permit #AOP-01-057.

If a SCR system is installed, the Permittee anticipates a reduction in the CO emissions because they will be able to optimize the boiler's combustion for more complete combustion rather than for low NO_X emissions. At this time it is not known how effective this optimization will be for reducing CO emissions, so no changes to the CO RACT is recommended at this time.

CO RACT with or without a NO_X SCR system will continue to be good combustion control with the same limits from permit #AOP-01-057.

These RACT determinations shall be reviewed in 5 years when this operating permit is due for its renewal.