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

TECHNICAL SUPPORT DOCUMENT

FOR

PERMIT TO CONSTRUCT

#AP-11-038

Permit Date: April 19, 2013

North Springfield Sustainable Energy Project, LLC
North Springfield, 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:
North Springfield Sustainable Energy Project, LLC
36 Precision Drive
North Springfield, VT 05150

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1.0 INTRODUCTION

North Springfield Sustainable Energy Project, LLC (hereinafter “Permittee”) has proposed to construct/install and operate wood fired electrical generating station, with an electrical generation rate of approximately 37 MW (net), at 36 Precision Drive in North Springfield, Vermont (also referred to herein as “Facility”). The parent corporation for North Springfield Sustainable Energy Project, LLC is Winstanley Enterprises, LLC.

Administrative Milestones:

Table 1-1: Administrative Summary

Administrative Item	Result or Date
Date Application Received:	12/29/2011
Date Administratively Complete:	12/29/2011
Date Draft Decision:	8/9/2012
Date & Location Draft Decision/Comment Period Noticed:	8/9/2012 *Claremont Eagle Times*
Date & Location Public Meeting Noticed:	8/9/2012 *Claremont Eagle Times*
Date & Location of Public Meeting:	8/29/2012 at Springfield High School
Deadline for Public Comments:	9/10/2012
Date Final Decision:	4/19/2013
Classification of Source Under §5-401:	§5-401(3): Electric power generation facilities
Classification of Application:	New Source Review/ Prevention of Significant Deterioration Construction Permit
New Source Review Designation of Source:	Major Stationary Source
Facility SIC Code(s) & Descriptions:	4911 – Electrical Services

The allowable emissions for the Facility are summarized below:

Table 1-2: Estimated Air Contaminant Emissions (tons/year)[1]						
PM/PM$_{10}$/PM$_{2.5}$	***SO_2***	***NO_x***	***CO***	***VOC***	***HAPs*** [2]	***CO_2e*** [3]
38.6	40.6	62.4	153.3	10.2	<10/25	448,714

[1] PM/PM$_{10}$/PM$_{2.5}$ - particulate matter, SO_2 - sulfur dioxide, NO_x - oxides of nitrogen, CO - carbon monoxide, VOC – volatile organic compounds, HAPs - hazardous air pollutants.
[2] Emissions of individual HAPs each < 10 tpy and emissions of total HAPs combined <25 tpy.
[3] CO_2e 'at the stack' – includes emissions from biogenic sources. See section 3.3 for details. This is not a facility limit.

Total PM emissions from the Facility, including both filterable and condensable components, are conservatively assumed to also be categorized as PM$_{2.5}$ and thus also PM$_{10}$. Filterable PM represents the PM that is in solid form in the heated exhaust gas at the point of sampling. Condensable PM represents pollutants that are in gaseous form in the heated exhaust at the point of sampling but will become PM upon cooling and condensing and includes high molecular weight organics.

2.0 FACILITY DESCRIPTION AND LOCATION

2.1 Facility Locations and Surrounding Area

North Springfield Sustainable Energy Project, LLC will be located at 36 Precision Drive in North Springfield, Vermont. The areas surrounding the Facility include mixed industrial, commercial, forested, and suburban residential land uses. The Facility is approximately 0.9 km from the western bank of the Black River. The Jeld-Wen door company is immediately to the west of the Project site. A gravel pit operation is immediately to the north and east of the project site. A non-operating gravel pit and concrete block plant is immediately to the south of the project site. A number of other small industrial firms are located immediately northwest of the Facility. To the north, south, and east of the Facility, the land use is mixed residential, farmland and forested areas. The Facility is located less than 1 km south of the center of North Springfield, and approximately 5 km to the northwest of Springfield, VT.

The Lye Brook Wilderness Area is approximately 41 km to the southwest of the Facility. The nearest Vermont designated sensitive area (elevation at or above 2500 ft elevation): is Mount Ascutney, with an elevation of 3,143 feet, located approximately 14.5 km northeast of the Facility.

2.2 Facility Description

Operations performed at the Facility are classified within the Standard Industrial Classification Code / North American Industrial Classification System Code 4911 - Electrical services (other electrical power generation) / 221119 - Other Electric Power Generation. Regulated sources of air contaminant emissions at the Facility are listed in Table 2-1, and Table 2-2 lists information on air pollution control equipment at the Facility.

TABLE 2-1: Equipment and Stack Information				
Equipment/Make/Model	Capacity/ Size	Fuel or input material	Air Pollution Control Equipment	Stack Height (feet)
Boiler: wood fired advanced fluidized bed boiler	Maximum annual average heat input (45%moisture content wood): 464 MMBtu/hr [1] Maximum short term [6] heat input (55%moisture content wood): 502 MMBtu/hr [1]	Natural Wood	Fabric filter and Selective Catalytic Reduction (SCR)	140
Four (4) auxiliary/start-up burners for the boiler	40 MMBtu/hr (each) 160 MMBtu/hr [1] (total)	ULSD [2]		
One (1): Emergency Diesel Engine Generator	3,000 kW [4]	ULSD [2]	Tier 2 per 40 *CFR* Part 89	-
Diesel Engine Fire Pump	450 bhp [5]		Tier 3 per 40 *CFR* Part 89	-

[1] MMBtu/hr – million British Thermal Units of heat input per hour
[2] ULSD – ultra low sulfur diesel (0.0015% or 15 ppm sulfur content).
[3] gpm – gallons per minute
[4] kW – rated kilowatt output
[5] bhp – rated brake horse power output
[6] Maximum short term heat input has been used to establish pollutant emission rates for review of short term NAAQS (≤24-hr standards).

Table 2-2: Air Pollution Control Equipment	
Boiler – Pulse-jet fabric filter dust collector	Inlet Temperature: 430 ^{o}F Maximum design flue gas rate: 260,000 acfm 6 compartments, each with 340 filter bags Nominal bag dimensions: 6” x 26.33’ (39.77 ft^2/bag) Total cloth filtering area: 81,130 ft^2, Air/Cloth = 3.2 (gross) 22 oz./yd^2 woven fiberglass with Teflon and ePTFE coating Pressure drop – typical range: 4.5 – 6.5” w.c.
Boiler - Selective Catalytic Reduction for NOx.	Inlet Temperature: 425 ^{o}F Details not available at this time. In series, following boiler fabric filter dust collector.

[1] The term fabric filter is synonymous with the term bag house for this document.

2.3 Description of Compliance Monitoring Devices

The Facility will be equipped with continuous emission monitoring systems (CEMS) which measures exhaust flow and the emission rates of NO_x, CO, NH_3, and CO_2 from the Boiler exhaust stack to the ambient air. In addition, the Facility will operate and maintain a continuous opacity monitoring system (COMS) which measures the opacity of the exhaust gas from the Boiler. If required by the Acid Rain Program, an SO_2 CEMS will also be used.

2.4 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 2-3 lists activities at the Facility which were considered trivial, negligible or exempt sources of air contaminant emissions, and therefore were not considered as emission sources as part of the Permit review.

Table 2-3: Negligible Sources of Contaminant Emissions	
Fuel storage tanks:	Diesel fuel storage tanks.
Fly ash storage silo	The Permittee has proposed to utilize a sealed fly ash handling system that conditions the ash with water before discharging the ash from the system as a wetted cake.

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.

2.5 Proposed Limitations

The Permittee has not proposed any operating limits for the Boiler. However, the annual potential to emit calculations are based on an average heat input of 464 MMBtu/hr (vs. the maximum design heat input of 502 MMBtu/hr), for 365 days per year, so the permit will have an annual heat input limit of 4,064,640 MMBtu/yr. Assuming 4,500 Btus per pound of 45% moisture wood, this equates to approximately 451,627 tons/yr of wet wood fuel.

In their application, the Permittee used 65 hours of operation to estimate the potential emissions from the diesel powered emergency generator and the diesel engine fire pump during routine testing and maintenance. The permit will include 65 hours as a limitation for the routine testing and maintenance of these diesel engines. Actual emergency hours of operation are not limited.

Short term emission limits are determined by MSER and/or HMSER determinations below.

3.0 QUANTIFICATION OF POLLUTANTS

The quantification of emissions from a stationary source is necessary in order to establish the appropriate regulatory review process for the operating permit application and to determine applicability of 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 Emission of Criteria Pollutants from the Proposed Stationary Source

For the Boiler, the calculated allowable annual emissions of SO_2, NO_X, PM, CO and VOCs are based on the established emission limits expressed in lbs/MMBtu and an annual average maximum heat input of 464 MMBtu/hr. Short term emission rates (for air dispersion modeling) will be based on the maximum design heat input of 502 MMBtu/hr. Since firing with ULSD only occurs at startup there are no separate emission limits established specifically for oil firing. The Facility is expected to comply with the long term emission limits (>24 hours) at all times (including startup) regardless of fuel. The short term limits for NOx, CO and VOC do not apply during the startup of the boiler. Start up emission limits for NOx, CO and VOC will be established from operating data, CEMS data as well as stack test data and will be included in the Facility's Title V Operating Permit.

Potential HAP emissions are based on a combination of emission factors from the U.S. EPA document, A Compilation of Air Pollutant Emission Factors (AP-42), emission data from the National Council for Air and Stream Improvement (NCASI) Technical Bulletin No. 858 and stack testing conducted at other biomass boilers in New England; additional details regarding this data is available in Section 3.2 of this document.

Table 3-1: Boiler - Allowable Emissions				
464 MMBtu/hr heat input x 8760 hours = 4,064,640 MMBtu/yr annual heat input				
	Emission Factor			Allowable Emissions tons per year
	Factor	Units [1]	Source	
SO_2	0.020	lb/MMBtu	MSER	40.6
NO_x – Annual	0.03	lb/MMBtu	MSER	61.0
NO_x – hourly	0.06	lb/MMBtu	MSER	-
$PM_{10}/PM_{2.5}/PM$ [2]	0.019	lb/MMBtu	MSER / HMSER	38.6
CO	0.075	lb/MMBtu	MSER / HMSER	152.4
VOC	0.005	lb/MMBtu	HMSER	10.2
HAPs	0.0075	lb/MMBtu	AP-42, Wood Residue Combustion in Boilers, Tables 1.6-3 and 1.6-4 (9/03), NCASI Technical Bulletin No. 858, representative stack tests.	15.3[3]

[1] lb/MMBtu: pounds of pollutant emitted per million British Thermal Units (HHV) of energy input to the boiler.
[2] PM: total PM including filterable and condensable fractions.
[3] No individual HAP exceeds 10 tons per year and combined HAPs are less than 25 tons per year.

Table 3-2: Diesel Generators – Allowable Emissions				
Emission estimate based on 65 hours 3000 kW Tier 2 Engine	**Emission Factor**			**Allowable Emissions, tons/yr**
	Factor	**Units**	**Source**	
SO_2	0.0015	lb/MMBtu	15 ppm sulfur content in fuel	0.0015
PM	0.2	g/kW-hr	EPA Tier 2 Engine	0.04
NO_X	6.4	g/kW-hr	EPA Tier 2 Engine	1.37
CO	3.5	g/kW-hr	EPA Tier 2 Engine	0.75
VOC	-	-	EPA Tier 2 Engine	-

Table 3-3: Fire Pump/Diesel Engine – Estimated Emissions				
Emission estimate based on 65 hours 450 hp Tier 3 Engine 23.5 gph	**Emission Factor**			**Allowable Emissions, tons/yr**
	Factor	**Units**	**Source**	
SO_2	0.0015	lb/MMBtu	15 ppm sulfur content in fuel	0.0002
PM	0.15	g/BHP-hr	EPA Tier 3 Engine	0.005
NO_X	3.0	g/BHP-hr	EPA Tier 3 Engine	0.10
CO	2.6	g/BHP-hr	EPA Tier 3 Engine	0.09
VOC	-	-	EPA Tier 3 Engine	-

Table 3-4: Summary of Allowable Air Contaminant Emissions by Source (tons/year)						
Source	***PM/PM_{10}***	***SO_2***	***NO_X***	***CO***	***VOC***	***Total HAPs***
Boiler	38.6	40.6	61.0	152.4	10.2	15.3
Diesel generators (1@3000kW)	0.04	-	1.37	0.75	-	-
Diesel fire pump	-	-	0.1	0.08	-	-
Facility Totals	**38.64**	**40.6**	**62.4**	**153.3**	**10.2**	**15.3**
Significance Levels	**25/15**	**40**	**40**	**50**	**40**	**-**

As summarized in Table 3-4 above:

- The Facility has allowable emissions of all air contaminants in the aggregate of ten (10) or more tons per year and has allowable emissions of carbon monoxide in excess of 100 tons per year: the Facility is therefore subject to Subchapter X of the Regulations and is designated as a Title V Subject Source. The Facility will be required to file an application for a Title V Permit to Operate within one year of commencing operation.
- The Facility has allowable emissions of NO_X and CO greater than 50 ton/year which classifies the source as a “Major Source” and therefore is subject to the new source review requirements of §5-502 of the *Regulations*. In addition, for a Major Source, the allowable emissions of the other criteria pollutants are reviewed to determine if they exceed their respective ‘significant emission rate.’ PM_{10} and SO_2 exceed their significant emission rates and will also be subject to §-502 of the *Regulations*. See section 5.0 for the review of the Most Stringent Emission Rate for the affected pollutants.
- The Facility is an electrical generating unit which uses fossil fuel (ULSD startup burners) and has a rating of > 25 MW; therefore the Facility is subject to the Acid Rain Program and the Permittee must file an Acid Rain permit application at least 24 months before commencing operation.

3.2 Estimating Emissions of Hazardous Air Contaminants.

The potential emissions of Vermont Hazardous Air Contaminants are estimated based on the maximum operating load for the Boiler and an appropriate emission factor. For this review the emission factors are based on a combination of sources that best represent the expected emissions from the respective sources: U.S. EPA AP-42, the National Council for Air and Stream Improvements (NCASI) and stack testing of similar wood fired boilers located in Vermont and the rest of New England.

Table 3-5 Quantification of HAC Emissions							
Hazardous Air Contaminant	CAS#	Toxic Category	Boiler Emission Factor	Boiler EF Source [1]	Facility Emission Rate	Action Level	Above Action Level?
			(lb/mmbtu)		(lb/8-hrs)	(lb/8-hrs)	
1,1,1-Trichloroethane	71556	II	3.10E-05	AP-42	1.15E-01	8.30E+01	
1,2-Dichloroethane (ethylene dichloride)	107062	I	2.90E-05	AP-42	1.08E-01	3.20E-03	Yes
1,2-Dichloropropane (propylene dichloride)	78875	I	3.30E-05	AP-42	1.22E-01	4.20E-03	Yes
2,4,6-Trichlorophenol	88062	I	2.20E-07	NCASI	8.17E-04	2.70E-02	
Acetaldehyde	75070	I	1.90E-04	NCASI	7.05E-01	3.80E-02	Yes
Acetone	67641	II	2.20E-04	NCASI	8.17E-01	2.61E+01	
Acrolein	107028	II	2.40E-04	AP-42 (LO)	8.91E-01	2.00E-03	Yes
Ammonia		II	6.00E-03	HMSER	2.23E+01	8.30E+00	Yes
Antimony		II	7.90E-06	AP-42	2.93E-02	3.00E-01	
Arsenic		I	4.00E-06	AP-42 (LO)	1.48E-02	1.90E-05	Yes
Barium		II	1.70E-04	AP-42	6.31E-01	4.00E-02	Yes
Benzene	71432	I	8.50E-04	AP-42 (LO)	3.16E+00	1.10E-02	Yes
Benzo(a)pyrene	50328	I	2.67E-06	NCASI	9.91E-03	4.00E-05	Yes
Beryllium		I	1.90E-06	NCASI	7.05E-03	3.50E-05	Yes
Bromodichloromethane	75274	I	3.00E-03	NCASI	1.11E+01	4.60E-03	Yes
Bromomethane (methyl bromide)	74839	II	1.50E-05	AP-42	5.57E-02	4.00E-01	
Cadmium		I	4.10E-06	AP-42	1.52E-02	4.60E-05	Yes
Carbon disulfide	75150	II	1.30E-04	NCASI	4.83E-01	5.45E+01	
Carbon tetrachloride	56235	I	8.90E-07	NCASI	3.30E-03	5.50E-03	
Chlorine	7782505	III	7.90E-04	AP-42	2.93E+00	1.00E-02	Yes
Chlorobenzene	108907	II	3.30E-05	AP-42	1.22E-01	2.00E-01	
Chloroform	67663	I	3.10E-05	NCASI	1.15E-01	3.60E-03	Yes
Chloromethane (methyl chloride)	74873	II	4.00E-05	NCASI	1.48E-01	7.50E+00	
Chromium (total)		II	2.10E-05	AP-42	7.80E-02	1.00E-02	Yes
Chromium, hexavalent		I	2.00E-06	AP-42 (LO)	7.42E-03	6.90E-06	Yes

Table 3-5 Quantification of HAC Emissions							
Hazardous Air Contaminant	CAS#	Toxic Category	Boiler Emission Factor	Boiler EF Source [1]	Facility Emission Rate	Action Level	Above Action Level?
			(lb/mmbtu)		(lb/8-hrs)	(lb/8-hrs)	
Cobalt		I	6.50E-06	AP-42	2.41E-02	8.30E-04	Yes
Copper (dusts & mists)		II	4.90E-05	AP-42	1.82E-01	2.00E-02	Yes
Cumene	98828	II	1.80E-05	NCASI	6.68E-02	3.32E+01	
Di-butyl phthalate	84742	II	3.30E-05	NCASI	1.22E-01	2.50E-01	
Dichloromethane (methylene chloride)	75092	I	5.40E-04	NCASI	2.00E+00	1.70E-01	Yes
Dinitrotoluene-2,4	121142	I	9.40E-07	NCASI	3.49E-03	4.20E-04	Yes
Ethanol	64175	II	6.80E-05	NCASI	2.52E-01	3.72E+01	
Ethylbenzene	100414	I	3.10E-05	AP-42	1.15E-01	8.30E+00	
Fluoranthene	206440	II	1.64E-06	NCASI	6.09E-03	1.20E+00	
Formaldehyde	50000	I	1.20E-03	AP-42 (LO)	4.45E+00	6.50E-03	Yes
Hexachlorobenzene	118741	I	1.00E-06	NCASI	3.71E-03	1.80E-04	Yes
Hexane	110543	II	2.90E-04	NCASI	1.08E+00	5.81E+02	
Hydrogen Chloride	7647010	II	8.34E-04	Test	3.10E+00	1.70E+00	Yes
Iron oxides - dusts & fumes		II	9.90E-04	AP-42	3.67E+00	1.00E+00	Yes
Isopropanol	67630	II	3.90E-03	NCASI	1.45E+01	1.84E+02	
Lead compounds		I	4.80E-05	AP-42	1.78E-01	8.30E-04	Yes
Manganese		II	8.60E-05	AP-42 (LO)	3.19E-01	4.00E-03	Yes
Mercury		II	3.50E-06	NCASI	1.30E-02	2.00E-02	
Methanol	67561	II	8.30E-04	NCASI	3.08E+00	9.70E+01	
Methyl ethyl ketone	78933	II	9.10E-06	NCASI	3.38E-02	4.15E+02	
Methyl Isobutyl Ketone	108101	II	2.30E-05	NCASI	8.54E-02	2.49E+02	
Molybdenum compounds (metal & insoluble)		II	2.10E-06	AP-42	7.80E-03	2.00E-01	
Naphthalene	91203	I	1.60E-04	NCASI	5.94E-01	2.00E-02	Yes
Nickel compounds		I	3.30E-05	AP-42	1.22E-01	1.70E-04	Yes
PCDD/PCDF (VT APCD Memo 2/7/2011)	-	I	1.38E-10	NCASI	5.12E-07	1.93E-09	Yes

Table 3-5 Quantification of HAC Emissions							
Hazardous Air Contaminant	**CAS#**	**Toxic Category**	**Boiler Emission Factor**	**Boiler EF Source [1]**	**Facility Emission Rate**	**Action Level**	**Above Action Level?**
			(lb/mmbtu)		**(lb/8-hrs)**	**(lb/8-hrs)**	
Pentachlorophenol	87865	I	5.10E-08	AP-42	1.89E-04	2.40E-03	
Phenanthrene	85018	II	7.21E-06	NCASI	2.68E-02	8.70E+00	
Phenol	108952	II	5.10E-05	AP-42	1.89E-01	5.30E+00	
Pyrene	129000	II	3.79E-06	AP-42	1.41E-02	8.70E-01	
Selenium		II	3.00E-06	NCASI	1.11E-02	1.50E-01	
Silver compounds (metal)		II	1.40E-04	NCASI	5.20E-01	6.60E-01	
Styrene	100425	I	6.40E-04	NCASI	2.38E+00	8.30E+00	
Sulfuric Acid Mist		II	9.19E-04	APCD	3.41E+00	2.70E-02	Yes
Tetrachloroethylene (perchloroethylene)	127184	I	3.82E-05	AP-42	1.42E-01	1.50E-02	Yes
Tin compounds (metal and inorganic)		II	3.90E-05	NCASI	1.45E-01	4.00E-01	
Toluene	108883	II	2.90E-05	NCASI	1.08E-01	2.49E+01	
Trichloroethylene	79016	I	3.00E-05	AP-42	1.11E-01	4.00E-02	Yes
Trichlorofluoromethane	75694	II	4.10E-05	AP-42	1.52E-01	4.66E+01	
Vanadium pentoxide		I	9.80E-07	AP-42	3.64E-03	8.30E-04	Yes
Vinyl Chloride	75014	I	1.80E-05	AP-42	6.68E-02	9.10E-03	Yes
Xylenes (includes o,m,p)	-	II	2.80E-05	NCASI	1.04E-01	8.30E+00	
Zinc oxide		II	4.20E-04	AP-42	1.56E+00	8.30E-02	Yes

[1] Sources of Emission Factors:

AP-42 = U.S. EPA document, A Compilation of Air Pollutant Emission Factors, 5th Edition.
AP-42 (LO) = An adjusted emission factor after auditing AP-42 for outlier data. Refer to the NSSEP permit application, Appendix A, Table A-2 for further details.
NCASI = National Council for Air and Stream Improvement (NCASI) Technical Bulletin No. 858.
Test = stack testing conducted at other biomass boilers in New England.
APCD = Based on Babcock & Wilcox technical paper: A System Approach to SO_3 Mitigation, and Motobec USA technical paper: Reducing SO_2 Emissions at Coal Fired Power Plants.
HMSER = Hazardous Most Stringent Emission Rate – see section 7.4 of this document.

3.3 – Estimating Potential Greenhouse Gas Emissions

The estimate for potential GHG emissions includes the distillate fuel oil that would be used for 4 cold startups of the boiler. Each cold startup is expected to take 11 hours and consume an estimated 9,000 gallons of distillate fuel. The estimate does not 'back-out' the reduced wood fuel usage during these startups, so the estimate for GHG is conservatively high.

Section 3.3 Estimation of CO_2e Emissions

Source ID	Source Description	Fuel Combusted	Potential/ Allowable Quantity Combusted	Units	Estimated wood usage (raw tons)	Estimated %MC for raw wood fuel
	Main Boiler	Wood Fuel	275,994	tons	451627	45.0%
	Auxilliary burners	Distillate Fuel Oil #2	36,000	gallons	0	0.0%
	Emergency engines	Distillate Fuel Oil #2	15,386	gallons	0	0.0%

The wood fuel emission factors are based on wood with 10% moisture content, so 451,627 tons @ 45% MC is converted to 275,994 tons @ 10% MC

Table 2. Total Company-Wide Stationary Source Fuel Combustion

Fuel Type	Quantity Combusted	Units
Distillate Fuel Oil #2	51,386	gallons
Wood Fuel	275,994	tons

Table 3. Total Company-wide CO_2, CH_4 and N_2O Emissions from Stationary Source Fuel Combustion

Fuel Type	CO_2 (kg)	CO_2 (lb)	CH_4 (kg)	CH_4 (lb)	N_2O (kg)	N_2O (lb)
Distillate Fuel Oil #2	524,465	1,156,246	21.3	46.9	4.3	9.4
Total Fossil Fuel Emissions	524,465	1,156,246	21.3	46.9	4.3	9.4
Wood Fuel	398,161,195	877,794,134	135,833	299,461	17,828	39,304
Total Non-Fossil Fuel Emissions	398,161,195	877,794,134	135,833	299,461	17,828	39,304
Total Emissions for all Fuels	398,685,660	878,950,380	135,855	299,508	17,832	39,314

	CO_2	CH_4	N_2O	CO_2e metric ton	CO_2e short ton
Global Warming Potential	1.0	21.0	310.0		
Total CO_2 Emissions - Equivalent (Fossil CO2e + Biogenic CH4 & N2O)				**8,905**	**9,817**
All CO2e emissions at stack (Fossil CO2e + Biogenic CO2e) - for APCD Permit info				**407,067**	**448,714**

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 point sources of air emissions 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. Based on the application submittal the Permittee is expected to comply with this regulation based on the use of Ultra Low Sulfur Diesel fuel oil certified by the supplier to contain no more 0.0015% (15 ppm) sulfur by weight and natural wood.

§5-231(3) - Prohibition of Particulate Matter; Combustion Contaminants
Based on the application submitted and information available to the Agency, this Facility has applicable fuel burning equipment subject to this regulation. The allowable particulate emissions based on minimum standards of 5-231(3) are shown in Table 4-1, however the Facility is limited to a more stringent emission standard under the MSER requirements of 5-502(3).

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

Equipment ID	*Size/Capacity*	*Emission Standard, lbs/MMBtu*	*Allowable Emissions, lbs/hr*
Boiler	502 MMBtu/hr	0.1	50.2

§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.

§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, the boiler is greater than 250 MMBtu/hr and is subject to this regulation 5-251(1) while burning fossil fuel. However the boiler is being held to a more stringent emission standard under the MSER requirements of 5-502(3). The Facility does not have allowable emissions of NO_X in excess of 100 tons per year and is therefore not subject to subsection 5-251(3).

§5-252 - Control of Sulfur Dioxide Emissions
Based on the application submittal and information available to the Agency, the boiler is greater than 250 MMBtu/hr and is subject to this regulation while burning fossil fuel. However the boiler is being held to a more stringent emission standard under the MSER requirements of 5-502(3).

§5-253.1 – 5-253.20 - Control of Volatile Organic Compounds
Based on the application submittal and information available to the Agency, this Facility currently has no applicable operations subject to this regulation.

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

§5-271 – Control of Air Contaminants from Stationary Reciprocating Internal Combustion Engines
This emission standard applies to all stationary reciprocating internal combustion engines with a brake horsepower output rating of 450 hp or greater. This section applies to the emergency generator and fire pump engine at the Facility.

4.2 Regional Greenhouse Gas Initiative Vermont CO_2 Budget Trading Program -

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative, market-based regulatory CO_2 emission trading program among nine Northeast and Mid-Atlantic states (States). Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. RGGI is intended to stabilize and then reduce emissions of CO_2 from fossil fuel-fired electrical generating systems with a nameplate capacity equal to or greater than 25 MWe. Sources subject to RGGI are required to purchase and hold allowances equivalent to their actual emissions of CO_2 over each three year control period and certify compliance at the end of each respective control period. Emission allowances are primarily auctioned by the States, which, in turn, invest the auction proceeds in energy-related consumer benefit programs.

Compliance with RGGI is defined and administered under the Vermont CO_2 Budget Trading Program Regulations (*Program Regulations*)

A "fossil fuel-fired electrical generating system" is defined under §22-102 of the *Program Regulations* as a unit where "*…the combustion of fossil fuel, alone or in combination with any other fuel, where the fossil fuel combusted comprises, or is projected to comprise, more than 50 percent of the annual heat input on a Btu basis during any year* ".

Although the generation capacity at the Facility has a nameplate rating of greater than 25 MWe, the Facility is not intended or projected to use greater than 50 percent fossil fuel for its annual heat input. As such, it is not subject to the requirements of RGGI or the *Program Regulations*.

4.3 Federal Air Pollution Control Regulations and the Clean Air Act

40 *C.F.R.* Part 60 Subpart Db – *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units*

"The affected facility to which this Subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 19, 1984 and that has a maximum design heat input capacity of greater than 29 megawatts (MW) (100 million BTU per hour).

The Boiler is subject to this regulation. However the boiler is held to more stringent emission standards through MSER.

40 *C.F.R.* Part 60 Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

Applies to CI RICE model year 2007 and newer. This regulation establishes emission rates for affected engines, requires routine engine maintenance and sets maximum sulfur content for the diesel fuel. Beginning October 1, 2010 applicable engines shall only use diesel fuel with a maximum sulfur content of 15 ppm (ULSD).

This regulation applies to the diesel engines that power the emergency generator and the fire pump at the Facility.

40 *C.F.R.* Part 63 Subpart JJJJJJ – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers – area sources.*

This regulation has requirements for emission limits (PM <0.03 lb/MMBtu heat input), work practice standards, operating limits for the PM control device, performance stack testing, and demonstrating continuous compliance (similar to Compliance Assurance Monitoring discussed below).

Since the Facility has HAP emissions less than 10 tons for each individual HAP and less than 25 tons for all HAPs combined it is classified as an area source of HAPs, not a major HAP source, and therefore this regulation applies to the Boiler rather than the major source regulation Subpart DDDDD.

<u>40 *C.F.R*. Part 63 Subpart ZZZZ</u> – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines. Applies to new engines installed after June 12, 2006 at area sources of HAPs. Requires such engines to meet the emission standards of NSPS Subpart IIII and JJJJ, imposes ULSD fuel limitations, and imposes maintenance requirements. Separate provisions of ZZZZ also apply to existing engines installed prior to June 12, 2006.

Subpart ZZZZ applies to the diesel engines that power the emergency generator and the fire pump at the Facility requiring them to meet NSPS Subpart IIII.

<u>Clean Air Act §§114(a)(3), 502(b), and 504(a)-(c); 40 CFR Part 70 §§70.6(a)(3)(i)(B) and 70.6(c)(1); and 40 CFR Part *64*</u> - *Compliance Assurance Monitoring.*

This Facility will be subject to CAM. The emissions of PM and NOx from the Boiler are subject to CAM because:

- the Facility is a Title V Subject Source;
- the uncontrolled emission rates of PM and NOx exceed their respective Title V major source thresholds (100 ton/yr);
- the emissions of PM (NSPS, MSER and HMSER) and NOx (MSER) are subject to an applicable rule;
- the Boiler is equipped with emissions control devices for each of these pollutants. Note that CO is controlled based on the bubbling fluidized bed boiler design which is not considered an emission control device for CAM, so CAM does not apply to CO for this Facility. Considering that the Facility is otherwise required to have a CO CEMS, CAM does not offer any additional significant monitoring benefits for CO.

The CAM Plan for this Facility will be included in the Title V Operating permit. The Facility is required to file an application for a Title V Operating permit within one year of commencing operation. The Facility is expected to establish the parameters of the CAM plan during the initial operating period of the Facility so they can be included in the CAM plan portion of the Title V operating permit application.

<u>40 *C.F.R.* Parts 72-78</u> – Acid Rain Program

The Permittee is required to operate the Facility under a permit that includes the Acid Rain Program requirements. This regulation requires that the Facility be equipped with a CEMS for opacity, exhaust flow, diluents, NO_X and SO_2 emissions, although the Permittee may petition EPA to use a default SO_2 emission factor pursuant to 75.11(e)(1) and (f). This regulation also requires the Permittee meet additional recordkeeping and reporting requirements. Pursuant to §72 the Facility is required to file an application for an Acid Rain permit at least 24 months prior to commencing operation.

<u>40 *C.F.R.* Part 98 – Mandatory Greenhouse Gas Reporting</u>

Pursuant to §98.2(a)(1)(i) the Permittee is required to report the Facility's greenhouse gas emissions from the Boiler.

4.4 Non-Applicable Requirements for Which a Permit Shield Provision Has Been Requested

Pursuant to §5-1015(a)(14) of the Regulations, an owner/operator may request to be shielded from potentially applicable state or federal requirements. The Facility has not requested a permit shield from any specific, potentially applicable requirement. Accordingly, the Agency has not granted any permit shields for the Facility.

5.0 CONTROL TECHNOLOGY REVIEW FOR MAJOR SOURCES AND MAJOR MODIFICATIONS

Pursuant to §5-502 of the Regulations each new major source and major modification must apply control technology adequate to achieve the Most Stringent Emission Rate ("MSER") with respect to those air contaminants for which there would be a major or significant emission increase, respectively. For those unfamiliar with Vermont's term MSER, it can be thought of as a functional equivalent to the federal Best Available Control Technology.

As shown in Tables 3-4 above, the Facility must achieve MSER for $PM/PM_{10}/PM_{2.5}$, SO_2, CO, and NO_x. Note that the emission rate of beryllium using available wood burning emission factor data also is estimated to exceed its significant emission rate of 0.0004 ton/yr. Since beryllium is also a HAC, it will be reviewed under §5-261 of the *Regulations* which establishes the Hazardous Most Stringent Emission Rate for HACs that are expected to be emitted at a rate that exceeds their Action Level.

MSER is established following the procedures identified in the Agency's "Air Pollution Control Permitting Handbook", NESCAUM's "BACT Guideline", and the U.S. EPA's "New Source Review Workshop Manual". The process of determining MSER is to first list all available options for reducing emissions and then rank the alternatives in order of effectiveness from top to bottom (top being the most effective). One of the sources for information on emission limits and control technologies for permitted facilities is the U.S. EPA's "RACT, BACT, LAER Clearinghouse (RLBC)." MSER requires the application of the top option unless it can be demonstrated based upon costs (economic, energy, and environmental) or technical constraints that such an option is not achievable for the proposed project. If the Agency concurs with the applicant that an option is not achievable, then the next most effective option is evaluated. This process may take several iterations before MSER is established.

MSER will be established for the following sources: Boiler and the emergency engines.

Wood Fired Boiler – MSER Determination:

5.1 Boiler - NO_X MSER Review

The NOx control alternatives identified in the permit application for the proposed Boiler, listed in order of effectiveness:

1. Selective catalytic reduction (SCR): Use of a catalyst to reduce NO_x to N_2. There are several approaches to using a catalyst for NOx reduction. One is hot side, conventional SCR, where the exhaust gases pass straight through the catalyst and out the stack. To achieve the necessary inlet temperatures, the SCR is placed immediately after the boiler on the "hot side" of the other emission control devices. In cases where the exhaust gases are too cool for the catalyst to function properly, additional heat is necessary to bring the exhaust gases up in temperature. In these systems, the added heat energy is often recovered by cycling back and forth over heat recovery media beds. This is referred to as a regenerative SCR (RSCR). Conventional SCR systems can achieve very high levels of emission reductions depending on the volume of catalyst and amount of ammonia used. RSCR systems have slightly lower performance due primarily to the cycling back and forth across the heat recovery beds. SCR had not been applied to wood-fired units until about 2004, having been considered technically infeasible due to the adverse impacts of alkaline materials in the wood ash that rapidly deactivate the catalyst. However, vendors of this technology have begun to overcome these issues by physical catalyst configuration, and by placing the catalyst downstream of the particulate removal device, thus avoiding the worst effects of fouling and degradation. This lower temperature zone also required reformulation of the catalyst material to obtain adequate reaction at temperatures 200 to 300^o F lower than the 600-750^o F that was the previous norm for SCR applications.
2. Selective non-catalytic reduction (SNCR): Reducing NO_x to N_2 by injection of ammonia or urea into the boiler exhaust gases at high temperature (1600 to 2100°F). This can achieve NOx reduction levels ranging from 30 – 50%. When combined with combustion controls, the overall NOx reduction can be in the range of 65 – 75%.
3. Combustion controls: Controlling the fuel/air mixing, excess air levels, and other combustion parameters to achieve efficient combustion and to control the stoichiometry in the combustion zone to minimize the formation of thermal NO_x. Combustion controls also include flue gas recirculation to lower combustion temperature and thermal NO_x formation. To varying degrees, these have become integral components in modern boiler design. The bubbling fluidized bed proposed herein varies FGR rates to compensate for variations in fuel moisture content to maintain the bed temperature of 1,300 to 1,600^o F. NOx formation increases exponentially with increased combustion temperature. In this range of bed temperature, very little thermal NOx is formed.

All of the above technologies are technically feasible. The Permittee is proposing to use a combination of 1 & 3 as MSER for NOx control. The catalyst system will be a selective catalytic reaction (SCR) that will reduce NOx emissions. In addition the Permittee is proposing a NOx limit of 0.06 lb/MMBtu based on a one hour block average and a long term NOx emission limit of 0.03 lb/MMBtu for an annual block average.

There are a number of wood fired electrical generating stations both proposed and operating in the northeast that utilize a selective catalytic reduction system for controlling NOx emissions. Some of these SCR systems are located as a "cold side" SCR and they incorporate a regenerative heat exchanger to maintain the proper temperatures some of which use a minimal amount of additional fuel to re-heat the exhaust gases.

Many of the operating facilities are controlling NOx emissions, on a long term basis (typically a 3 month average) to qualify for the Massachusetts or Connecticut renewable energy credit markets. Since the REC markets with the highest value credits allow for a maximum quarterly NOx emission rate of 0.065 and 0.075 lb/MMBtu, this is the typical range of demonstrated emission rate performance for this technology.

Two of the most recently proposed projects in Massachusetts: Palmer Renewable Energy and Pioneer Renewable Energy have proposed to achieve a NOx emission rate of 0.055 lb/MMBtu based on a one hour block average. The Palmer Renewable Energy project has also proposed an annual average NOx emission rate of 0.017 lb/MMBtu. Since neither of these projects has been constructed and these emission rates have not been demonstrated, they are not being considered as a basis to lower the proposed NOx emission rates for the project under review.

Table 5-1: NO_X Emission Limits and Performance

Facility	Nominal Rating	Permit Date	NO_X Controls	NO_X Limit (lb/MMBtu)	NO_X Emission Performance
Pioneer Renewable Energy, Greenfield, MA	47 MW	Application pending	MPCR	0.055 (1 hr block) 0.022 (12 month block)	Plant has not been built.
Beaver Wood Energy – Fair Haven	34 MW	2/10/2012	MPCR	0.060 (1-hr block) 0.030 (12-month avg)	Plant has not been built.
Palmer Renewable Energy, Springfield, MA	38 MW	6/30/2011	Combustion control, OFA, HRSCR [1]	0.055 (1 hr block) 0.017 (12 month avg))	Plant has not been built.
Warren Co. Biomass – GA	100 MW	12/17/2010	SNCR	0.10 (30 day rolling avg)	Plant has not been built.
Clean Power Berlin, Berlin, NH	29 MW	9/25/2009	Staged combustion & SCR	0.065 (30 day avg)	Plant has not been built.
Laidlaw Berlin BioPower, Berlin, NH	70 MW	7/26/10	SCR	0.060 (30 day rolling avg)	Under construction.
Montville Power, Uncasville, CT	42 MW	4/6/10	RSCR	0.06 (24 hr block)	Plant has not been built.
Boise White Paper - AL	435 MMBtu/hr	3/23/2010	LNB	0.30	Plant has not been built.
Lindale Renewable Energy – TX	50 MW	1/8/2010	SNCR	0.15	Plant has not been built.
Lufkin Generating Plant - Lufkin, TX	45 MW	10/26/09	SCR	0.075 (30 day avg)	Started August 2011
Concord Power & Steam Concord, NH	19.5 MW	8/12/2011	SCR	0.065 (30 day avg)	Plant has not been built.
McNeil Generating Station - Burlington, VT	50 MW	2/2/09	RSCR	0.075 (Quarterly block)	2010 Quarterly averages: 0.067, 0.072, 0.072, 0.069.
Russell Biomass, Russell, MA	50 MW	12/30/08	RSCR	0.060 (12 month rolling avg)	Plant has not been built.
Yellow Pine Energy Company Fort Gaines, GA	115 MW	5/15/09	SNCR	0.10 (30 day rolling avg)	Plant has not been built.
Koda Energy – MN (120,000 lb/hr steam plus 17.8 MW)	308 MMBtu/hr	8/23/2007	SNCR	0.25 (30 day rolling avg)	Started operation in 2009
Simpson Tacoma Kraft – WA (Power Boiler #7)	340,000 lb/hr steam	12/12/2011	Combustion Controls w/ over-fire air (OFA)	0.20 (30 day avg) Changing to 0.30 (30 day avg)	Operating. OFA design unable to meet the 0.20 NOx limit.
PSNH - Schiller Station (Unit SR5) Portsmouth, NH	50 MW	3/7/06	SNCR	0.075 (24 hr avg)	Based on CEMS, 1st qtr 2011 estimated at 0.064 lb/MMBtu

[1] HRSCR – high efficiency regenerative selective catalytic reduction system. The proposed system at this facility includes an oxidative catalyst as well for reducing CO and VOC emissions.

Based on review of the proposed alternatives, the Agency concurs that MSER for NOx is the use of combustion controls with a SCR and the following NOx emission rates: Hourly average of 0.060 lb/MMBtu of heat input and a 12 month rolling average of 0.030 lb/MMBtu of heat input.

5.2 Boiler – Particulate Matter ("PM/PM_{10}") MSER Review

The alternatives identified in the permit application for the proposed wood fired Boiler- listed in order of effectiveness:

1. Electrostatic Precipitator (ESP) or fabric filter
2. Wet scrubber
3. Dry Scrubber
4. Multi-clone

Either a fabric filter or ESP can achieve 99.9+% PM removal. Although ESPs have been historically favored for wood-fired units, primarily over fire-related concerns with fabric filters, a few fabric filters have been placed in operation in the past few years and have demonstrated their viability. Fabric filters are generally considered equal to ESPs for overall PM control but to have slightly superior fine particle control. Furthermore, fabric filters tend to be installed in lower flue gas temperature zones which promotes condensation of various compounds onto the solid material that is then efficiently removed by the filters, rather than, in a conventional unit, condensing in the atmosphere to form PM_{10}/$PM_{2.5}$.

A wet scrubber can achieve removal efficiencies in the high 90s percent range, though the sludge and wastewater handling and processing is much more involved and costly than dry ash handling. Wet processed ash tends also to be less marketable as a reusable by-product. Wet scrubbers tend to be utilized only when there is a specific acid gas removal issue that needs to be addressed in addition to PM control.

Dry scrubbers, when utilized, precede a fabric filter and are generally limited to projects wherein acid gas removal is a concern. Similarly, sorbent injection may be used to resolve a site-specific issue.

Multi-clones sometimes precede the high-efficiency particulate removal device as a means to substantially decrease the loading of that device so that it can be designed and operated more efficiently. Multi-clones are virtually never used alone any more as they remove much less than 90% of the PM. Although they are listed last above, they are sometimes a part of any modern PM collection system.

All of the above technologies are technically feasible.

The Permittee is proposing the use of a fabric filter as MSER for PM/PM_{10} control. In addition, the Permittee is proposing a filterable PM emission limit of 0.010 lb/MMBtu and a total PM (filterable + condensable PM) limit of 0.019 lb/MMBtu.

The Agency asked the Permittee about the potential use of multi-cyclones up stream of the fabric filters in order to help minimize the potential for damaging (burning) the filter bags due to char/cinder carry over. The vendor, Babcock and Wilcox (B&W), replied as follows: While the use of multi-cyclones (mechanical dust collectors – “MDC”) are common practice for wood fired stoker/grate fired settings, bubbling fluid bed combustors have inherently better combustion characteristics that result in reduced char carry over, unburned carbon loss, and lower carbon monoxide emissions. With prudent fuel management and operating practice, B&W’s experience is that an MDC is not necessary with a properly designed BFB combustion system. B&W’s design philosophy incorporates low velocity plenums and drop-out hoppers prior to the fabric filter. While an MDC could offer an additional margin of protection against cinder carry over, this would come at a higher capital and operational cost.

In the Table 5-2 is a summary of the PM emission limits of several recently permitted wood fired boiler EGUs, as well as the two wood fired EGUs currently operating in Vermont.

The Agency has not found enough PM emission data on large boilers to adequately characterize the contribution of the condensable portion of the PM, so we are not requiring a lower emission rate for total PM. The condensable PM data that has been gathered suggests that the emission rate of 0.008 lb/MMBtu for Seneca Sustainable Energy for total PM is not expected to be consistently achievable.

Based on review of the proposed alternatives, the Agency concurs that the best available control technology for PM/PM_{10} emissions from the Boiler is the use of a fabric filter and a filter PM emission rate of 0.010 lb/MMBtu in addition to a total PM emission rate of 0.019 lb/MMBtu.

Table 5-2: PM/PM_{10} Emission Limits and Performance

Facility	Nominal Rating	Permit Date	PM Controls	PM/PM_{10} Limit (lb/MMBtu)	PM Emission Performance
Pioneer Renewable Energy, Greenfield, MA	47 MW	Application pending	Multi-clone, ESP	Filterable PM: 0.012 Total PM: 0.019	Plant has not been built.
Beaver Wood Energy – Fair Haven	34 MW	2/10/2012	Multi-clone, ESP	Filterable PM: 0.010 Total PM: 0.019	Plant has not been built.
Palmer Renewable Energy, Springfield, MA	38 MW	6/30/2011	Dry scrubber, fabric filter	Filterable PM: 0.008 Total PM: 0.015	Plant has not been built.
Ryegate Power Station East Ryegate, VT	20 MW	5/16/2011	Multi-clone, ESP	Filterable PM: 0.007 gr/dscf (0.016 lb/MMBtu)	Average of 9 stack tests since 1993: 0.0013 lb/MMBtu (filterable PM)
Warren Co. Biomass Energy facility – GA	100 MW	12/17/2010	Sorbent injection and fabric filter	Filterable PM_{10} 0.010 Filterable $PM_{2.5}$ 0.018	Plant has not been built.
Laidlaw Berlin BioPower, Berlin, NH	70 MW	7/26/10	Fabric filter	Filterable PM: 0.01	Under construction
Montville Power, Uncasville, CT	42 MW	4/6/10	Multi-clone, ESP	Filterable PM: 0.012 Total PM: 0.026	Plant has not been built.
Lindale Renewable Energy, TX	50 MW	1/8/2010	Good combustion practices & ESP	Filterable PM: 0.02 (30-day avg)	Plant has not been built.
Lufkin Generating Plant, Lufkin, TX	45 MW	10/26/09	ESP	Filterable PM: 0.012 Total PM: 0.025 Both 30 day rolling avg	Started August, 2011
Seneca Sustainable Energy, Eugene, OR	18.8 MW	10/9/09	Multi-clone, ESP	Total PM: 0.008	Stack tests completed.
Seneca Sustainable Energy: There are ongoing issues with demonstrating compliance on a long term basis that include complications from the condensable PM test method which had problems with test artifacts causing false high PM emissions.					
Russell Biomass, Russell, MA	50 MW	12/30/08	Multi-clone, ESP or fabric filter	Filterable PM: 0.012 Total PM: 0.026	Plant has not been built.
Yellow Pine Energy Company - Fort Gaines, GA	115 MW	5/15/09	Fabric filter	Filterable PM: 0.010 Total PM: 0.018	Plant has not been built.
Koda Energy – MN 120,000 lb/hr steam + 17.8 MW	308 MMBtu/hr	8/23/2007	Cyclone & ESP	Total PM: 0.03 Filterable PM_{10}: 0.037 (3 hr avg)	Started operation in 2009
Simpson Tacoma Kraft – WA (Power Boiler #7)	340,000 lb/hr steam	12/12/2011	Existing ESP	Filterable PM_{10}: 0.02 0.01 gr/dscf @ 7% O2	Operating

Table 5-2: PM/PM_{10} Emission Limits and Performance

Facility	Nominal Rating	Permit Date	PM Controls	PM/PM_{10} Limit (lb/MMBtu)	PM Emission Performance
PSNH - Schiller Station (Unit SR5) Portsmouth, NH	50 MW	3/7/06	Fabric filter	Filterable PM: 0.025 (at all times) 0.01 (24-hour avg)	Stack tests (filterable PM) 5/6/10: 0.001 lb/MMBtu 5/13/09: 0.001 lb/MMBtu Stack test 11/17 & 11/28/06: 0.0007 lb/MMBtu filterable PM 0.0117 lb/MMBtu condensable PM 0.0124 lb/MMBtu total PM
McNeil Generating Station, Burlington, VT	50 MW	2/2/09	ESP	Filterable PM: 0.007 gr/dscf (0.016 lb/MMBtu)	Stack tests (filterable PM) 7/14/04: 0.00060 lb/MMBtu 10/26/10: 0.00015 lb/MMBtu

5.3 Boiler – Carbon Monoxide (CO) MSER Review

The alternatives identified in the permit application for the proposed wood fired Boiler- listed in order of effectiveness:

1. Oxidative catalyst.
2. Good combustion design and combustion practices.

Oxidation catalysts have not historically been successfully applied to wood fired units. Until recently, they were considered technically infeasible for reasons similar to the fouling and degradation experienced with SCR catalysts. Recent designs have moved them to the clean side and, hence, cooler operating zone. Although an oxidation catalyst is more efficient at higher temperatures, such temperatures occur only on the high-ash side of the particulate removal system where fouling and catalyst degradation are a problem. Thus cold-side installations have lower CO removal efficiencies than those, for example, used in gas-fired combustion turbine-based combined cycle power plants.

Combustion controls incorporated in any modern boiler design reduce CO emissions to well below those of older boilers. The BFB boiler can achieve CO emissions rates comparable to a stoker unit equipped with an oxidation catalyst.

Table 5-3 contains a summary of CO emissions levels for permits recently issued to facilities with wood fired boilers. The most stringent short term emission limits are 0.07 (4 hr avg) to 0.075 lb/MMBtu (24 hr avg) for recently permitted units incorporating oxidation catalysts. The most stringent annual average CO emission rate is proposed for Pioneer Renewable and included in the air permit for Palmer Renewable in Massachusetts. Neither facility has been built or operated, so neither this annual average, nor the 0.07 lb/MMBTU (4-hr avg) have been demonstrated and should not be considered as a basis for lower CO emission limits.

All of the above technologies are technically feasible. The Permittee is proposing to use a bubbling fluidized bed boiler to achieve an emission of 0.075 lb/MMBtu (24-hr average) as MSER for CO control.

Based on review of the proposed alternatives, the Agency concurs that MSER for CO is the use of a bubbling fluidized bed boiler and a limit of 0.075 lb/MMBtu of heat input as a 24 hour rolling average.

In response to comments regarding CO BACT in the draft permit, the Agency instructed the Permittee to conduct additional analysis to determine the cost effectiveness of using a an oxidation catalyst for their boiler to achieve 0.0365 lb/MMBtu. The addition of an oxidative catalyst to achieve a reduction in CO from 0.075 lb/MMBtu to 0.0365 lb/MMBtu would result in a potential reduction in annual CO emissions of 74 tons. The estimated cost to add a CO catalyst is $16,800/ton of CO controlled (includes cost to install and an estimated catalyst life of 3 years, which requires an estimated cost of $1,200,000 to replace the catalyst). Based on these costs, which can be considered in an MSER determination, the Agency determined that 0.075 lb/mmbtu still constitutes MSER for CO.

Some pollutants, such as CO may be elevated during startup conditions, either due to less than optimum combustion during these periods, or in the case of NOx due to the SCR not functioning until normal operating temperatures are reached. The Permittee has requested that emission limits for startup be established with the Boiler Operation and Maintenance Plan to include proposed startup and shutdown emission limitations for NOx, CO and VOC, developed from operational emission data from stack tests and/or CEMs data collected during startup and shutdown periods. The Agency concurs with this request.

Table 5-3: CO Emission Limits and Performance

Facility	Nominal Rating	Permit Date	CO Controls	CO Limit (lb/MMBtu)	CO Emission Performance
Pioneer Renewable Energy, Greenfield, MA	47 MW	Application pending	Combustion Control and CO catalyst	0.114 (1 hr block) 0.07 (4 hr block) 0.0365 (12 month rolling avg)	Plant has not been built.
Beaver Wood Energy – Fair Haven	34 MW	2/10/2012	Combustion Control and CO catalyst	0.075 (24-hr avg)	Plant has not been built.
Palmer Renewable Energy, Springfield, MA	38 MW	6/30/2011	Combustion Control and CO catalyst	0.114 (1 hr block) 0.07 (4 hr block) 0.0365 (12 month rolling avg)	Plant has not been built.
Warren Co. Biomass Energy facility – GA	100 MW	12/17/2010	Good design and operating practices	0.08 (30 day rolling avg)	Plant has not been built.
Laidlaw Berlin BioPower, Berlin, NH	70 MW	7/26/10	BFB boiler & FGR	0.075 (calendar day)	Under construction.
Montville Power, Uncasville, CT	42 MW	4/6/10	CO catalyst	0.10 (8 hr block)	Plant has not been built.
Lindale Renewable Energy, TX	50 MW	1/8/2010	Combustion control	0.31 (30 day avg)	Plant has not been built.
Lufkin Generating Plant, Lufkin, TX	45 MW	10/26/09	Combustion control	0.075	Started August, 2011
Russell Biomass, Russell, MA	50 MW	12/30/08	Combustion Control and CO catalyst	0.075	Plant has not been built.
Yellow Pine Energy Company - Fort Gaines, GA	115 MW	5/15/09	BFB	0.149 (30 day avg)	Plant has not been built.
Koda Energy – MN 120,000 lb/hr steam + 17.8 MW	308 MMBtu/hr	8/23/2007	Combustion Control	0.35 (30 day avg)	Started operation in 2009
Simpson Tacoma Kraft – WA (Power Boiler #7)	340,000 lb/hr steam	12/12/2011	Combustion Controls w/ over-fire air (OFA)	0.35 (30 day avg) 600 ppm @ 7% O2, 30 day rolling average	Operating
PSNH - Schiller Station (Unit SR5) Portsmouth, NH	50 MW	3/7/06	Good combustion w/ fluidized bed	0.10 (24 hr avg)	Plant operating and using CEMS to monitor CO emissions.

5.4 Boiler - Sulfur Dioxide (SO_2) MSER Review:

The alternatives identified in the permit application for the proposed wood fired Boiler- listed in order of effectiveness:

1. Wet scrubber
2. Spray dryer.
3. Dry sorbent injection.
4. Use of low sulfur content fuel:

Wet scrubbers inject a water-based solution of sodium hydroxide or calcium-based reagent into the flue gas. The water absorbs the SO_2 and the reagent reacts with it to form sodium or calcium sulfate, which can be precipitated from the spent solution and disposed of as a solid waste. Wet scrubbers are generally the technology of choice when dealing with flue gas from high- or medium-sulfur coal firing. They are very efficient at removing SO_2 when the initial driving force for the reactions is a high SO_2 concentration, such as when the fuel is high-sulfur coal or oil. Wet scrubbers are technically challenged and not cost effective when starting at a very low SO_2 concentration in the flue gas and so have not been applied to wood-fired plants, where the fuel sulfur content is much lower than coal or residual oil. A wet scrubber is not considered to be practical or cost-effective for the NSSEP project, and would have other environmental impacts.

A spray dryer injects a reagent-water solution that reacts with the SO_2. The water then evaporates in the heat of the flue gas, leaving behind dry particles to be removed, typically in a fabric filter. Spray dryer-absorber systems like wet scrubbers, are not cost-effective unless applied to relatively high concentration flue gas streams. Spray dryers (dry scrubber) are generally applied to low- and medium-sulfur coal and oil-fire facilities and are not considered to be technically feasible for the NSSEP unit.

Table 5-4 contains a summary of SO_2 emissions levels for permits recently issued to facilities with wood fired boilers. A few projects have proposed scrubber technology, including Palmer Renewable in MA, with the same short term emission rate as proposed for NSSEP (0.02 lb/MMBtu). Palmer has not been built and had originally been proposed as a C&D wood boiler which included the dry scrubber.

Dry sorbent injection (DSI) systems add trona or sodium bicarbonate as dry particles into the flue gas. Reaction with SO_2 takes place on the surface of the particle, binding the sulfur, and the particles are removed in a downstream fabric filter. DSI is less costly than wet systems as well as being better suited to lower SO_2 concentrations in the flue gas. For this project, the estimated cost of control for a DSI system using trona in 1-ton flexible intermediate bulk containers (supersacks) is $14,700/ton of SO_2 controlled. If a full bulk storage and handling system is required, the cost of control nearly doubles. DSI has been used on a few wood-fired plants when the fuel supply was found to have higher-than-expected sulfur content or as a precaution to accommodate fuels of varying sulfur content. Variations in the sulfur content of wood do occur both locally and regionally depending on sulfur uptake rates from the soil in which the tree is grown. Monitoring of SO_2 emission at the two operating wood fired EGUs in Vermont indicates that there are very low emission rates of SO_2 from the combustion of wood in this region.

The Permittee is proposing that wood as a low sulfur fuel represents MSER for SO_2 control. In addition, the Permittee is proposing a SO_2 limit of 0.02 lb/MMBtu. The averaging period will depend on whether a CEMS is required by the EPA Acid Rain program.

Based on review of the proposed alternatives, the Agency concurs that the MSER for SO_2 is the use of wood as a low sulfur content fuel and a limit of 0.02 lb/MMBtu of heat input based on an hourly average.

Table 5-4: SO_2 Emission Limits and Performance					
Facility	**Nominal Rating**	**Permit Date**	**SO_2 Controls**	**SO_2 Limit (lb/MMBtu)**	**SO_2 Emission Performance**
Warren Co. Biomass Energy facility – GA	100 MW	12/17/2010	Sorbent injection	0.010 (30 day rolling avg)	Plant has not been built.
Laidlaw Berlin BioPower, Berlin, NH	70 MW	7/26/10	Sorbent injection (as needed)	0.012 (stack test)	Under construction
Yellow Pine Energy Company - Fort Gaines, GA	115 MW	5/15/09	Dry scrubber system	0.014 (30 day avg)	Plant has not been built.
Beaver Wood Energy – Fair Haven	34 MW	2/10/2012	None	0.020	Plant has not been built.
Lufkin Generating Plant, Lufkin, TX	45 MW	10/26/09	None	0.025 (30 day avg)	Started August, 2011
Lindale Renewable Energy, TX	50 MW	1/8/2010	Low sulfur fuels	0.025 (30 day avg)	Plant has not been built.
Seneca Sustainable Energy, Eugene, OR	18.8 MW	10/9/09	None	0.025	Stack test completed; results were not available at this time
Montville Power, Uncasville, CT	42 MW	4/6/10	Low sulfur fuels	0.025 (3-hr block avg)	Plant has not been built.
Pioneer Renewable Energy, Greenfield, MA	47 MW	Application pending	Low sulfur fuels	0.025	Plant has not been built.
Palmer Renewable Energy, Springfield, MA	38 MW	6/30/2011	Sorbent injection, Turbosorp scrubber	0.02 (1-hr avg) 0.012 (annual avg)	Plant has not been built.
PSNH - Schiller Station (Unit SR5) Portsmouth, NH	50 MW	3/7/06	Dry sorbent injection [1]	0.02	Plant operating and using CEMS to monitor SO_2 emissions.

[1] Schiller Station is also permitted to burn coal in Unit SR5.

Diesel Engines MSER Determination:

The Facility will include a 3 MW diesel engine to provide power through emergency generators and a 450 hp diesel-driven fire water pump. These engines are sources of NO_X, CO, PM, and SO_2.

MSER for the engines will be met through the use of new engines that are Tier certified in accordance with 40 *CFR* Part 60 Subpart IIII, and a limit of 65 hours/year for maintenance and exercising of the engines.

Facility Greenhouse Gas Emissions MSER Review:

The science and technical issues regarding the effect of a bioenergy facility on carbon stocks and overall carbon emissions is complex and evolving. On June 3, 2010, EPA finalized new thresholds for greenhouse gas emissions that define when Clean Air Act permits are required (also known as the "Tailoring Rule"). In January 2011, Vermont adopted the Tailoring Rule thresholds for greenhouse gas emissions in the Vermont Air Pollution Control Regulations. In July 2011, EPA deferred for a period of three years the application of permitting requirements to biogenic carbon dioxide (CO_2) emissions and committed to conducting a detailed examination of the science and technical issues associated with accounting for emission of biogenic CO_2 emissions.

Vermont has not amended its regulations to defer the applicability of permitting requirements for biogenic CO_2 emission sources such as NSSEP. However, because a carbon accounting method has not yet been developed to accurately adjust a bioenergy facility's actual stack emissions up or down based on the induced changes in carbon stocks on land (in soils, plants and forests), such sources are currently subject to air permitting requirements in Vermont based solely on direct CO_2 emissions from the stationary sources. In other words, at this time, air permitting for biogenic stationary sources is not taking into account possible supplemental emissions such as from depleted soils after harvesting or any future carbon sequestration that could result from the use of biogenic feedstocks. Likewise, the Agency is not establishing wood procurement requirements in its air permits for biogenic sources at this time. This may change in the future, for example when an accounting method for biogenic CO_2 emissions from the stationary sources is finalized.

The Agency reserves its right to raise any issues related to the management of forest resources, and the potential impact of this or any other facility, in the context of other proceedings such as Act 250, Section 248, or other permitting regimes.

5.5 Boiler Greenhouse Gas MSER Review:

One of the central questions to determining BACT for GHGs for this project is whether alternative fuels as a control option would fundamentally redefine the proposed facility or whether alternative fuels should be included as a control option in determining BACT/MSER. In doing so, the Agency "must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emission reductions without disrupting the applicant's basic business purpose for the proposed facility." In re Prairie State Generating Co., 13 E.A.D. 1, 23 (EPA 2006). The crucial question to consider in determining whether a control option, such as alternate or cleaner fuels, would redefine the project is "when does the imposition of a control technology require enough of a redesign of the proposed facility that it strays over the dividing line to become an impermissible redefinition of the source?" In re Desert Rock Energy Company, PSD Appeal No. 08-03 et al. at 63-64 (EAB Sept. 24, 2009).

The Permittee is proposing to construct a 37 MWe (net, average) biomass fuel electric generating facility in North Springfield, Vermont. The Permittee maintains that the choice of biomass fuel is integral to the proposed facility's fundamental purpose and basis of design and reiterated that alternative fuels would fundamentally redefine the project. According to information supplied in connection with the Permittee's air permit application and application for a Certificate of Public Good, the Permittee designed and sited the facility based on the Permittee's conclusion that there is sufficient biomass fuel in the project area. The Permittee relies on a biomass fuel supply study for the area surrounding the facility location conducted by Innovative Natural Resource Solutions, LLC for the Permittee, along with a recent study by the Biomass Energy Resource Center (Vermont Wood Fuel Supply Study – 2010 Update), as the basis for its conclusion that there is an ample supply of wood fuel available. The Agency has not undertaken, as part of the air permitting process, an independent analysis of the conclusions reached in the aforementioned wood supply studies, and has considered the studies for the limited purpose of addressing whether alternative fuels should be included as a control option in determining BACT/MSER.

The Agency finds that the Permittee's objective is to build a biomass fuel electric generating facility. Based on the air permit application and other statements made by the Permittee, the Agency also finds that the Permittee has "defined its 'goal, objectives, purpose, or basic design' for the proposed facility," In re Desert Rock Energy Company, PSD Appeal No. 08-03 et al. at 65 (EAB Sept. 24, 2009), based on the Permittee's conclusions regarding the availability of biomass wood fuel. Thus, for the limited purpose of considering whether alternative fuels should be included as a control option in determining BACT/MSER, the Agency concludes that the Permittee's choice of fuel is integral to the proposed facility's fundamental purpose and basic design. Thus, imposing alternate fuels such as coal, natural gas, or oil as a control option would fundamentally redefine the proposed facility. For these reasons, the Agency finds that such alternate fuels should not be included as a control option in determining MSER. With respect to alternative biogenic fuels, the Agency finds there is currently not sufficient availability of other biogenic fuels (such as grasses, agricultural byproducts, bio oils from seed crops or bio gases from digesters) to contribute significant fuel energy to a project such as the North Springfield Sustainable Energy Project.

Step 1: Identify all Control Technologies: The alternatives identified in the permit application for the proposed wood fired Boiler- listed in order of effectiveness:

1. Carbon capture and storage (CSS). CSS technologies are still in the development stage. CSS is promising as a CO_2 control technology for a source that has exhaust gases with high-purity CO_2 streams.
2. Energy efficiency. The design of a traditional boiler-steam-turbine-generator system loses the majority of its potential energy at two points in the system: (a) the turbine's

condenser via the cooling water and/or cooling air and (b) the boiler's exhaust gases exiting the stack. Recovery of potentially lost heat energy should increase the plant's overall energy efficiency.

   a. The cooling water from the condenser has a temperature in the range of 80 – 90^{o}F, and is very limited in potential for additional heat recovery. At electrical utility plants this warm water is sometimes discharged directly to a large river in a process known as once thru cooling. However many rivers cannot environmentally absorb this added heat and it must be cooled before discharging. For the current project, a large river is not available and the water must be cooled and reused. The current project will send the condensing steam from the steam turbine to an air cooled condenser, then the returning water can be reused in the boiler.
   b. A portion of the heat in the hot exhaust gas can be extracted by further cooling of the gases via the installation of additional heat exchangers. The current project includes an economizer for combustion air preheating following the SCR system for heat recovery ahead of the stack.

3. Combined heat and power (CHP). CHP offers the advantage of extracting additional heat energy from the low grade heat (low pressure steam) and/or other waste heat that may be available from the boiler process. The basic principle of CHP is to direct some of the thermal energy to nearby thermal heating requirements (typically process heat or building heat) which are inherently more energy efficient than converting the thermal energy (steam) into electrical energy via a steam turbine generator.
4. Type of fuel. Due to their chemical makeup, some fuels generate less CO_2 per unit of energy when they are combusted. As noted above, fuel switching would redefine this source and is not part of the MSER review.
5. Good operating and maintenance practices. This is an extension of energy efficiency; make sure that the equipment is operating at peak performance to help ensure that the overall system efficiency remains as designed. This would include minimizing air leaks into the boiler system through procedures and methods to detect air leakage, in addition to maintaining proper insulation on the steam and condensate lines and identifying and repairing condensate leaks. In addition, covering the main wood fuel pile will serve to minimize rain infiltration into the stored wood.

Step 2: Eliminate Technically Infeasible Options:

1. CSS: At this time, CSS technologies have not been developed for capturing CO_2 in the dilute exhaust gases being emitted from biomass combustion. Therefore, CSS, is not technically feasible for this project. In addition, there can be a significant energy penalty in moving this gas stream under high pressure to the underground geological formations for sequestration.
2. Energy efficiency is technically feasible, within limits. The recovery of waste heat from the boilers exhaust gases is limited due to the potential of condensing the moisture in the gases which can adversely affect the condition of the exhaust handling equipment if it is not designed for this potential corrosive environment. In addition, cooler exhaust gases have worse dispersion characteristics after exiting the exhaust stack. The Permittee's boiler design includes an economizer after the SCR which reduces the exhaust gas temperature to the range of 250 – 310 ^{o}F.

3. CHP is technically feasible. The Permittee has stated their intent to utilize low pressure steam, from an extraction point off the turbine, to produce warm water which will be used as a thermal heat loop for other businesses in the industrial park.
4. Good operating and maintenance practices to maintain system performance is technically feasible.

Step 3: Rank Remaining Control Technologies by Control Effectiveness:

1. Energy efficiency
2. CHP – through the recovery of low grade heat to produce hot water for a thermal loop in the North Springfield Industrial Park. The applicant has indicated that there is an anticipated heat demand from the existing industrial park buildings for up to 20,000 lb/hr of low pressure steam. The annual average heat demand is estimated to be 4,000 lb/hr.
3. Good operating and maintenance practices does not reduce GHG emissions, but it does help ensure that the facility continues to operate as designed.

Steps 4 & 5 are combined since the Facility will be using all three of the control technologies identified in Steps 1 through 3.

The Agency has determined that MSER for GHGs is implementing energy efficiency, a thermal loop to provide heat to businesses in the industrial park, and good operating and maintenance practices for GHG control. In addition, a CO_2e emission limit has been established based on the annual average heat input to the boiler (464 MMBtu/hr), an electrical output of 36.72 MW, an average annual output of the thermal loop of 4 MMBtu/hr and a plant long term performance heat rate "degradation" of 3%. In spite of good operating and maintenance practices, it is expected that there will be some loss of performance over time. The plant's heat rate degradation is estimated to have a long term average of 0.15%/yr; the value of 3% is based on 20 years of operation. The CO_2e emission limit is 2,675 lb CO_2e / MW-hr net electrical and heat output based on a 12 month rolling average.

The applicant will be allowed to phase in the implementation of the heat loop to the industrial park. For the first 2 years of the operation of the boiler, the CO_2e emission limit will not be based on the operation of the heat loop, and will be 2,668 lb CO_2e / MW-hr net electrical output based on a 12-month rolling average. This limit does not include any energy sent to the thermal loop and does not include the 3% heat rate degradation.

Starting with the 3rd year of operation, the CO_2e emission limit will be 2,675 lb CO_2e / MW-hr net electrical and heat output based on a 12-month rolling average.

5.6 Diesel Engine Greenhouse Gas MSER Review:

The Agency is not aware of any technologies that have been designed to reduce the GHG emissions from diesel powered emergency engines generators and/or fire pumps. Energy efficiency of the engine design is the best way to minimize the emissions of GHGs from these sources. Since the EPA's engine emission standards for other criteria pollutants are based on the emission rate of the pollutant per unit of energy output, engine manufactures have employed a combination of reducing the mass emission rate of the pollutant(s) and increasing the overall efficiency of the engines. Thus the use of a Tier certified engine will help ensure the use of highest energy efficient diesel engine(s) available.

The Agency has determined MSER for GHGs from the emergency diesel engine will be met through the use of new engines that are Tier certified in accordance with 40 *CFR* Part 60 Subpart IIII.

6.0 AMBIENT AIR QUALITY IMPACT ANALYSIS

An ambient air quality impact evaluation is performed to demonstrate whether or not a proposed project will cause or contribute to violations of the ambient air quality standards and/or significantly deteriorate existing air quality. The Agency's implementation procedures concerning the need for an ambient air quality impact evaluation under §5-406(1) of the Regulations, specifies that such analyses may be required when a project results in an allowable emissions increase of ten (10) tons per year or more of any air contaminant, excluding VOCs.

6.1 Model Data Inputs

For this review, EPA's AERMOD model was used for both screening and interactive modeling. The meteorological data sets were for the years 2006 – 2010 which were recently developed using the 1 minute ASOS data. The surface met data was from the Springfield (Hartness) Airport, and the upper air data was from Albany, NY.

Since the issuance of the draft permit on 8/9/2012, an updated review, unrelated to the air permit, of the proposed stack height relative to the location of the Hartness Airport runway indicated that the stack was just tall enough that it exceeded a FAA criteria so a further study would be required. The project decided to lower both the base elevation for the main boiler building and the stack base by 1 foot. This brought the stack tip below the FAA criteria. To confirm that this change would not affect the previous modeling analysis, changes were made to the model inputs to reflect the new elevation of both the stack and the main boiler building and the model was re-run. The results showed that most of the modeled concentrations remained unchanged while a few changes by a small amont (less than 1%). The tables in this section have been updated, as needed with the new data. There are no changes in the Agencies review and conclusions.

The Permittee conducted modeling for several operating load scenarios for the boiler as well as a startup scenario for the boiler. This is necessary since full load operation does not necessarily correspond to the highest emission rate or worst dispersion. In some cases, lower operating loads can result in higher ambient impacts due to either higher emission rate concentrations (even though lower mass) or lower temperature or velocity of the exhaust. The startup scenario modeling was for short term emission (less than 24-hour standards) for CO (1-hr) and SO_2 (1-hr and 3-hr). Table 6-1 summarizes the operating loads and emission rates for the operating scenarios that were modeled.

Table 6-1: Operating Load Scenarios

% Load/ Fuel Moisture	Heat Input (MMBtu/hr)	Gas Flow (ACFM)	Stack Gas Exit Velocity (ft/sec) (m/s)	Stack Gas Exit Temperature (°F) (°K)	NOx Emission Rate (lb/hr) (g/s)	SO_2 Emission Rate (lb/hr) (g/s)	PM10/2.5 [1] Emission Rate (lb/hr) (g/s)	CO Emission Rate (lb/hr) (g/s)
100/55	502	190,956	63.32 19.3	310 427	30.12 3.795	10.04 1.265	9.538 1.202	37.65 4.744
100/45	464	161,555	53.57 16.3	300 422	27.84 3.508	9.28 1.169	8.816 1.111	34.80 4.385
75/45	344	114,795	38.06 11.6	270 405	20.64 2.601	6.88 0.864	6.536 0.824	25.80 3.251
60/35	262	88,141	29.23 8.9	250 394	15.72 1.981	5.24 0.660	4.978 0.627	19.65 2.476
Cold start	40	13,000	4.3 1.3	250 394	N/A	0.6 0.0076	N/A	60 7.56
Emission rates are "short term." Annual NOx emission rate is half the maximum 100%/45% hourly rate. Although other loads will not normally operate on an annual average basis (13.92 lb/hr), maximum short term emission rates were conservatively used for annual average impacts.								

[1] The PM emission is assumed to all be fine enough to be characterized as $PM_{2.5}$. This PM emission therefore also represents PM_{10}.

6.2 NAAQS Analysis

Based on the above scenarios, the emissions from the facility were modeled to establish the significant impact area (SIA). The SIA is based on the distance from the facility to the maximum point at which predicted impacts fall below the Significant Impact Level (SIL). The SIA is a circle around the facility with a radius equal to this distance. If there are no predicted impacts greater than the SIL for a pollutant then there is no SIA and interactive modeling is not necessary.

Table 6-2 shows that the emissions for $PM_{2.5}$, NO_X, and SO_2 are predicted to exceed one or more their respective SILs, so it was necessary to include any sources that met the above noted criteria as interactive sources in the modeling analysis.

Table 6-2: Distance to Significant Impact Level (km)				
Pollutant	**Averaging Time**	**Significant Impact Levels (μg/m^3)**	**Distance (km) from project**	**Load Case**
PM_{10}	24-hour	5	0.1	60/35
	Annual [1]	1	No impacts > SIL	N/A
$PM_{2.5}$	24-hour [2,4]	1.2	7.0	60/35
	Annual [2,4]	0.3	2.25	100/45
SO_2	1-hour [2,3]	7.8	15.1	100/55
	3-hour	25	No impacts > SIL	N/A
	24-hour	5	0.1	60/35
	Annual	1	No impacts > SIL	N/A
NO_2	1-hour [2,3,5]	7.5	37.9	100/55
	Annual [5,6]	1	No impacts > SIL	60/35
CO	1-hour	2,000	No impacts > SIL	N/A
	8-hour	500	No impacts > SIL	N/A

[1] Note that effective 12/28/2006, the EPA revoked the PM_{10} annual NAAQS standard. However, up until May 2011, in certain cases, the EPA allowed a PM_{10} surrogate policy that allowed a project to demonstrate compliance with the PM_{10} annual NAAQS as a means to also demonstrate compliance with the $PM_{2.5}$ annual NAAQS. This permit demonstrated compliance with the $PM_{2.5}$ annual NAAQS and did not propose to use the PM_{10} surrogate policy. Since the application for this permit included information on the PM_{10} annual NAAQS, we are including this information in this document.
[2] Averaged over 5 years per applicable EPA guidance.
[3] High 1st High maximum daily 1-hr concentration averaged over 5 years.
[4] High 1st High (100%) maximum concentration averaged over 5 years.
[5] NO_2 uses ARM values for NO_X to NO_2 conversion (0.75 for Annual, 0.8 for 1-hour).
[6] Annual NO_2 emissions based on guaranteed rates. Hourly NO_2 emissions represent maximum emissions. Conservative for reduced load conditions.

For the pollutants/averaging times with predicted impacts below their respective SIL, the monitored background concentrations were added to the appropriate modeled concentrations for a comparison with the NAAQS. Table 6-3 summarized this NAAQS review. Since there are no nearby sources of PM_{10} or $PM_{2.5}$ that will require cumulative source modeling these pollutants are included in this review. Table 6-3 shows that for the list pollutants there are no predicted exceedances of the NAAQS.

Table 6-3: NAAQS Review
Predicted Impact Concentrations for Pollutants Not Requiring Cumulative Source Modeling

Pollutant	Averaging Time [1]	Operating Load Scenario [2]	Modeled Conc. ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
PM_{10}	24-hr (H6H)	100/45	3.83	35.0	38.8	150
	Annual (H)	100/55	0.55	13.3	13.9	50
$PM_{2.5}$	24-hr [4]	60/35	4.44	19.1	23.5	35
	Annual [5]	100/45	0.51	7.8	8.3	15
SO_2	3-hour (H2H)	100/45	17.1	73.3	90.4	1,300
	Annual (H)	100/55	0.58	7.6	8.2	80
NO_2 [3]	Annual (H)	60/35	0.90	16.4	17.3	100
CO	1-hour (H2H)	100/45	117.7	3,435	3553	40,000
	8-hour (H2H)	100/55	36.3	1,832	1868	10,000

[1] H = highest annual average; H2H = highest second high value; H6H = Highest 6th high value over 5 years of meteorological data.
[2] 100/55 = 100% load / 55% moisture; 100/45 = 100% load / 45% moisture; 60/35 = 60% load / 35% moisture.
[3] For annual NO_2 modeling, used ambient ratio method of 0.75 for NO/NO_2 conversion.
[4] High 1st High (100%) maximum concentration averaged over 5 years.
[5] Averaged over 5 years per applicable EPA guidance.

The Agency used the following criteria to determine if the emissions from a nearby source would need to be included in the interactive modeling for this Facility:

1. Each pollutant for which a SIA has been identified, shall include the following class of nearby sources in the interactive modeling:
    a. Nearby sources located within the SIA with actual emissions greater than the following significant emission rates:
        i. CO: 50 tons/yr
        ii. NOx: 40 tons/yr
        iii. SO2: 40 tons/yr
        iv. PM10: 15 tons/yr
        v. PM2.5: 10 tons/yr
    b. Nearby sources located within 20 km of the wood boiler stack that have actual emissions greater than 50 tons/yr.
    c. Nearby sources located within 50 km of the wood boiler stack that have actual emissions greater than 500 tons/yr.

Based on the above noted criteria the interactive source modeling included emissions of NO_X and SO_2 for the following two sources: APC Paper and Wheelabrator, both located in Claremont, NH. There were no nearby sources of $PM_{2.5}$ or PM_{10} that met the criteria noted above. The stack and emissions data for APC Paper and Wheelabrator were supplied by the NHDES and are summarized in Table 6-4.

Table 6-4: Cumulative Source Stack and Emissions Data									
Source	**UTM E (m)**	**UTM N (m)**	**Stack Base Elev. (m)**	**Stack Height (m)**	**Stack Gas Temp. (K)**	**Stack Gas Velocity (m/s)**	**Stack Diam. (m)**	**Short Term SO_2 (g/s)**	**Short Term NO_X (g/s)**
APC Paper	714956	4805760	137.8	38.1	493	7.67	1.37	13.056	3.049
Wheelabrator Claremont	712571	4802400	164.6	45.7	421	24.62	0.79	1.991	5.756

The emissions from the proposed Facility (for the 4 operating load scenarios listed in Table 6-1) along with the emissions from the two facilities noted above were modeled to predict the maximum impacts to determine if there were any predicted NAAQS violations for the 1-hr NO_2, 1-hr SO_2 and 3-hr SO_2 NAAQS.

Table 6-5 summarizes the results of the cumulative source modeling results. For the 24-hr SO_2 NAAQS there were no predicted violations. For both the 1-hr NO_2 and 1-hr SO_2 there are predicted violations of the NAAQS.

The NSSEP ‘contribution’ shown in Table 6-5 of the draft permit has been updated. Table 6-5, shown below has the updated values which are higher than those shown in the draft permit, but still below the SILs. The data in the draft permit showed the Facility’s contribution that coincided with the form of the standard (4^{th} high for SO_2 and 8^{th} high for NO_2).Further review of the data showed that a higher contribution from the Facility could and did occur at other, lower overall cumulativeconcentrations that were over the NAAQS. The highest contribution for any modeled exceedance is shown in the updated table.

Table 6-5: Cumulative Source Modeling Results						
Pollutant / Avg Time	**Load %/ Moisture %**	**Overall Cumulative Concentration (µg/m³)**	**NAAQS (µg/m³)**	**Number of Receptors Exceeding NAAQS**	**NSSEP Contribution (µg/m³) [1]**	**Significant Impact Levels (µg/m³)**
NO_2 [2] 1-hour	100%/55%	246	188	12	2.63	7.5
	100%/45%	246		12	3.19	
	75%/45%	246		12	4.06	
	60%/35%	246		12	3.56	
SO_2 1-hour	100%/55%	805	195	263	0.06	7.8
	100%/45%	805		263	0.07	
	75%/45%	805		263	0.09	
	60%/35%	805		263	0.11	
SO_2 24-hour	100%/55%	149.3	365	0	N/A [3]	N/A [3]
	100%/45%	149.3		0		
	75%/45%	149.3		0		
	60%/35%	149.3		0		

[1] Highest contribution from NSSEP for the affected receptors to any modeled exceedance.
[2] NO_2 1-hour SIL = 7.5 µg/m³. Uses 0.8 for modeled 1-hour ARM for NOx to NO_2 conversion.
[3] N/A – Since below NAAQS, no further analysis is required.

To determine if the Facility's emissions cause or contribute to a violation of the 1-hour NO_2 or SO_2 NAAQS, it is necessary to identify the Facility's contribution to impacts at the receptors that have a total impact that is greater than the NAAQS.

There were 263 receptors with combined source 1-hour SO_2 impacts greater than the NAAQS. The Facility's maximum contribution to the impacts at any of these receptors was 0.11 µg/m^3 which is below the SIL of 7.8 µg/m^3. This demonstrates that the Facility does not cause or contribute to any violation of the 1-hour SO_2 NAAQS.

There were 12 receptors with combined source 1-hour NO_2 impacts greater than the NAAQS. The Facility's maximum contribution to the impacts at any of these receptors was 4.06 µg/m^3 which is below the SIL of 7.5 µg/m^3. This demonstrates that the Facility does not cause or contribute to any violation of the 1-hour NO_2 NAAQS.

<u>Start-up scenario:</u>
During the first few hours of a cold startup, the cold equipment, fuel transitions and a very low operating rate contribute to low flow rates and temperatures of the exhaust gases and subsequently reduced dispersion from the exhaust gas. This can result in elevated higher pollutant impacts during cold startup conditions. Since cold startups are expected to occur infrequently, longer term averaging times were not evaluated.

The Permittee modeled the estimated emission of CO (1-hr) and SO_2 (1-hr and 3-hr) from a cold startup scenario. The emission rates are shown in Table 6-1. For SO_2 the emission rate during the first few hours of a cold startup are lower due to the use of ULSD fuel. The modeled impacts for both the 1-hr and 3-hr SO_2 were well below their respective SILs and NAAQS. During the cold startup, the emission rate of CO (in terms of lb/MMBtu) is much higher compared with steady state/full load operation. This higher emission rate was modeled and demonstrated that the modeled 1-hr CO impacts were below both the SIL and the NAAQS. These results are summarized in Table 6-6.

Table 6-6: Modeling Startup Conditions

Pollutant	Averaging Time	Modeled Conc. (μg/m^3)	SIL (μg/m^3)	Background (μg/m^3)	Total Impact (μg/m^3)	NAAQS (μg/m^3)
SO_2	1-hour	0.62	7.8	70.7	71.3	195
	3-hour (H2H)	0.51	25	73.3	73.8	1,300
CO	1-hour (H2H)	745	2000	3,435	4180	40,000

The results of this refined modeling, shown in Section 6.2 above, demonstrate that the Facility will not cause or contribute to a violation of the NAAQS.

6.3 Prevention of Significant Deterioration (PSD) Increment Analysis

Major new sources of air pollution must demonstrate that the proposed project will not significantly deteriorate the existing air quality in regions that have been established as being in attainment of federal air quality standards. All of Vermont has been determined to be in attainment, or unclassified, for all of the federal air quality standards. Significant deterioration is considered to have occurred if the air quality impact concentration of the facility alone exceeds the remaining PSD increment value. In Vermont, major new sources are allowed to consume no more than 75% of the available short term increment and no more than 25% of the available annual increment.

Vermont and the U.S. EPA have adopted PSD increments for three classifications of geographical areas. Except for the Lye Brook Wilderness Area near Manchester, VT, all of Vermont is considered Class II. The Lye Brook Wilderness Area is classified as Class I. Class I areas are afforded greater protection under air pollution control laws in order to preserve their more pristine characteristics.

Nearby sources that consume increment are to be included in the PSD increment analysis for the proposed project in order to determine what the remaining available increment is to the proposed source. Certain facilities that have increased their emissions of respective pollutants since the respective baseline date are considered to have consumed increment. A review of the sources near the proposed Facility has determined that there are no nearby sources that consume increment for NO_2, SO_2, $PM_{2.5}$, or PM_{10}.

Table 6-7 summarizes the results of the predicted PSD increment impacts. The maximum predicted impacts for both Class I and Class II areas are less than the available increment.

Table 6-7: PSD Increment Impacts

Pollutant	Averaging Time	Max Impact ($\mu g/m^3$)		PSD Increment Standard ($\mu g/m^3$)		Available Increment in Vermont ($\mu g/m^3$)[1]	
		Class I	Class II	Class I	Class II	Class I	Class II
PM_{10}	24-hour	0.12	3.8	8	30	6	22.5
	Annual	0.016	0.55	4	17	1	4.25
$PM_{2.5}$	24-hour	0.15	4.4	2	9	1.5	6.75
	Annual	0.014	0.51	1	4	0.25	1
SO_2	3-hour	0.79	17.1	25	512	18.76	384
	24-hour	0.14	5.8	5	91	3.75	68.25
	Annual	0.017	0.58	2	20	0.5	5
NO_2	Annual	0.018	0.90	2.5	25	0.625	6.25

[1] Vermont regulations allow major new sources to consume only 25% of the annual increment and 75% of the short term increment.

6.4 Class I Air Quality Related Values Analyses

For facilities that are further than 50 km from a Class 1 Area, the Federal Land Managers Air Quality Related Values (AQRV) Workgroup (FLAG) has established a method to screen out from AQRV review those sources with relatively small amounts of emissions and/or located a large distance from a Class I area (a.k.a. Q/d). However, the Facility is located within 50 km distance of the Lye Brook Wilderness, so the Permittee must evaluate the air pollution effects from their proposed project on the AQRVs for the impacted Class 1 area.

6.4.1 Class I Area Air Quality Impact Modeling

New sources must demonstrate compliance with all National Ambient Air Quality Standards as well as demonstrate that there will not be any exceedances of any PSD Increments. As discussed in Section 6.2 of this document, the predicted impacts from this project will not exceed any NAAQS; this includes the Lye Brook Wilderness Area. As shown in Section 6.3, the air quality impacts were predicted for the Lye Brook Wilderness Area and compared to the PSD increments: the impacts were below the available increments. Any growth associated with this project is not expected to result in secondary emissions which need to be included in the NAAQS review or the PSD increment review.

6.4.2 Visibility Impairment

The visibility regulations for new source review (40 *CFR* §51.307 and §52.27) require visibility impact analysis in PSD areas for major new sources or major modifications that have the potential to impair visibility in any Class I area. An “adverse impact on visibility” means visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor’s visual experience of the Class I area. The Permittee conducted a Level 1 Screening Procedure as outlined in EPA’s Workbook for Plume Visual Impact Screening and Analysis using EPA’s VISCREEN model (Version 1.01 dated 88341). VISCREEN is used to calculate the potential visual impact of a plume of emissions for specific transport and meteorological conditions. Based on the results of this Level 1 Screening Procedure using VISCREEN, the proposed Facility’s plume will not cause adverse visual impacts inside the Lye Brook Class I area.

Table 6-8: Class I Visibility Modeling Results
Maximum Visual Impacts Inside the Class I Area

					Delta-E		Absolute Contrast	
Background	Theta (°)	Azimuth (°)	Distance (km)	Alpha (°)	Screening Criteria	Plume	Screening Criteria	Plume
SKY	10	135	52.7	34	2.00	0.891	0.05	0.014
SKY	140	135	52.7	34	2.00	0.431	0.05	-0.009
TERRAIN	10	84	41.4	84	2.00	1.957	0.05	0.015
TERRAIN	140	84	41.4	84	2.00	0.145	0.05	0.002

6.4.3 Class I Area - Deposition Analysis

The Permittee performed a modeling analysis to estimate the deposition of total nitrogen and total sulfur to the Lye Brook Wilderness Area. AERMOD was selected to perform this deposition modeling. The gaseous and particulate deposition rates were modeled separately, and the results summed at each receptor to obtain total deposition. Both wet and dry deposition was evaluated. The average annual emissions rates were adjusted to represent only the sulfur or nitrogen (versus SO_2 or NO_x) emitted.

The summed gaseous and particle deposition results are compared to the Deposition Analysis Threshold (DAT) of 0.010 kg/ha-yr (0.001 g/m^2-yr) for nitrogen and 0.010 kg/ ha-yr (0.001 g/m^2-yr) for sulfur.

The maximum predicted total sulfur deposition from the proposed facility (100% load/55% moisture) at any Lye Brook Wilderness Area receptor is 2.20×10^{-4} g/m^2-yr or 22% of the DAT.

The maximum predicted total nitrogen deposition from the proposed facility (75% load/45% moisture) at any Lye Brook Wilderness Area receptor is 1.77×10^{-4} g/m^2-yr or 18% of the DAT.

6.5 Additional Impact Analysis

As required by federal PSD regulations, 40 *CFR* 52.21(o), the Permittee included in the permit application additional impact analysis of: (a) the impairment to visibility, soils and vegetation that would occur as a result of the new major source and general, commercial, residential, industrial, and other growth associated with the new major source, except that an analysis of the impact on vegetation having no significant commercial or recreational value is not required; (b) the air quality impact projected for the area as a result of the general commercial, residential, industrial, and other growth associated with the facility.

Vermont's *State Implementation Plan*, states that impacts on vegetation, soils and an assessment of secondary growth will be conducted through procedures established in Title 10 Chapter 151, *Vermont Statures Annotated.* Section 6081 of this law requires the review and issuance of an Act 250 Land Use Permit for all significant changes in land use throughout the state. This section includes all secondary growth and all development of a nature likely to impact soils and vegetation through emissions to the ambient air. When the SIP was written, it was assumed that all development in Vermont would be required to obtain an Act 250 Land Use Permit. Since the Facility under review is an energy facility, it is required to just obtain approval through Act 248. For this project, the Air Pollution Control Division will perform the review to ensure that the project will not cause the impairment of visibility, soils and vegetation due to the direct effects of the facility or due to secondary growth associated with the construction of this new source of air pollution.

6.5.1 Growth Analysis

The peak construction work force is estimated to be 125 persons. The facility expects to employ a staff of 20-30 employees for plant operations.

It is expected that a significant construction force is available and is supported by the fact that within New England, significant construction activities have already occurred (including construction of a number of existing power projects). Therefore, it is expected that because this area can support the Project's construction from within the region, new housing, commercial and industrial construction will not be necessary to support the Project during the building period.

For any new personnel moving to the area as a permanent employee to support the Project operations once constructed, a significant housing market is already established and available. Therefore, no new housing is expected. Further, due to the small number of new individuals expected to move into the area to support the Project and the significant level of existing commercial activity in the area, new commercial construction is not foreseen to be necessary to support the Project's permanent work force. In addition, no significant level of industrial related support will be necessary for the Project, thus industrial growth is not expected. No new significant emissions from secondary growth during either operations, or the construction phase, are anticipated.

6.5.2 Ambient Air Quality

New sources must demonstrate compliance with all National Ambient Air Quality Standards as well as demonstrate that there will not be any exceedances of any PSD Increments. As discussed in Section 6.2 of this document, the predicted impacts from this project will not exceed any NAAQS. As shown in Section 6.3, the air quality impacts were predicted for the Lye Brook Wilderness Area and compared to the PSD increments: the impacts were below the available increments. As noted in Section 6.5.1, there are no new significant emissions expected from secondary growth associated with this project, so NAAQS review and the PSD increment review adequately reflect the potential impacts from this proposed facility.

6.5.3 Effects on Soils, Vegetation, and Secondary Impact Analysis

New major sources and major modifications are required to evaluate the effects of their air pollution emissions on soils and vegetation in the impact area. Any permit application for such a project is expected to provide a characterization of the soils and vegetation in the impact area and an evaluation of any adverse economic and ecological effects from the ambient concentration projected by the air quality modeling.

Evaluation of impacts on sensitive vegetation was performed by comparison of predicted project impacts with screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, 1980). The assessment was performed by adding the Facility impacts with ambient background concentrations and comparing the total to vegetation sensitivity screening levels presented in Table 3.1 of EPA's screening procedure.

The screening levels represent the minimum screening levels at which visible damage or growth effects to vegetation may occur. Screening levels have been established for the following pollutants that will be emitted from the Facility:

- 1-hour, 3-hour and annual SO2,
- 4-hour, 8-hour, monthly and annual NO2,
- Weekly CO,
- Monthly beryllium, and
- Quarterly lead.

The same background concentrations were used for NO_2, SO_2, and CO as shown in Table 6-3 above. The closest beryllium background values are available from the Underhill, VT monitoring station. There are monitors near Lye Brook and in Underhill and Burlington Vermont that provide data for lead in $PM_{2.5}$. Burlington will be used to represent the background value for this project. In addition, data is not presented for all averaging periods being examined. In those cases, the next shortest averaging period was used to conservatively estimate background.

Table 6-9 presents the results of the vegetative impact analysis. The modeled concentrations from the Facility, in combination with representative background values, are less than the vegetation sensitivity concentrations. Therefore, the air pollution emissions from Facility will not adversely impact vegetation in the area.

Table 6-9: Vegetative Impact from Criteria Pollutants

Pollutant	Averaging Time	Maximum Modeled Concentration (µg/m^3)	Background Concentration[1] (µg/m^3)	Total (µg/m^3)	Intermediate Vegetation Sensitivity Concentration (µg/m^3)	Resistant Vegetation Sensitivity Concentration (µg/m^3)	Sensitive Vegetation Sensitivity Concentration (µg/m^3)	Load %/ Moisture % Case
SO_2	1 HOUR	31.4	70.7	102.1	-	-	917.0	100%/45%
	3 HOUR	17.1	73.3	90.4	2096.0	13100.0	786.0	100%/45%
	ANNUAL	0.6	7.6	8.2	18.0	18.0	18.0	100%/55%
CO	WEEKLY (5)	21.6	1832.0	1853.6	-	18000000.0	1800000.0	60%/35%
NO_2 (6)	4 HOUR (4)	41.1	77.1	118.2	9400.0	16920.0	3760.0	100%/45%
	8 HOUR	23.3	77.1	100.4	7520.0	15040.0	3760.0	100%/55%
	MONTHLY (5)	13.8	77.1	90.9	564.0	564.0	564.0	60%/35%
	ANNUAL (7)	0.9	16.4	17.3	94.0	94.0	94.0	60%/35%
BERYLLIUM	MONTHLY	0.001	0.0000058	0.001	0.01	0.01	0.01	60%/35%
LEAD	QUARTERLY	0.026	0.0042	0.030	1.5	1.5	1.5	60%/35%

[1] From VTDES (SO_2, CO & NO_2) and AIRData Website (Lead)
[2] Background was conservatively estimated for: Use of 1-hour values for 4-hour, 8-hour and monthly NO_2, and use of 8-hour CO values for weekly CO.
[3] High Second High values used for all short term averages. High values used for annual.
[4] 4-hour value conservatively based on modeled 3-hour value.
[5] Weekly, Monthly, and Quarterly modeled concentration averages conservatively based on modeled 24-hour average.
[6] NO_2 uses ARM values for NO_X to NO_2 conversion (0.75 for Annual; , 0.8 for 4-hour, 8-hour & Monthly).
[7] Annual NO_2 emissions based on guaranteed rates. Hourly NO_2 emissions represent maximum emissions (100%/45%).

The EPA screening procedure also contains threshold levels for several elements to assess the impacts of trace element deposition to soil. Table 3.4 in the screening procedure lists the screening level for the concentration of the listed elements in the soil. The procedure also shows how to estimate the element deposition concentration in the impacted soils based on the annual average concentration of the pollutant.

Equation 5.1: DC (ppmw) = 21.5 * (N/D) * X

Where:

DC = deposited concentration (ppmw),
N = expected lifetime of source (yr),
D = depth of soil through which deposited material is distributed (cm), and
X = maximum annual average ambient concentration from the source ($\mu g/m^3$).

The procedure recommends using a value of 40 years for the expected lifetime of the source (N), and a soil depth of 3 cm (d).

The maximum annual average ambient concentration can be estimated by using the results of the NAAQS modeling. For an emission rate of 1 gram/second, the modeled maximum annual average ambient concentration is 0.4538 $\mu g/m^3$ (100%/55% load scenario). Table 3-5 of this document has the emission factors and mass emission rate for these listed elements. By multiplying the element's estimated emission rate (in terms of g/s), and multiplying by the normalized modeling impact (0.4538 $\mu g/m^3$/ 1 g/s) yields a calculated maximum annual concentration for the element.

Table 6-10 summarizes the potential deposition concentrations for the listed elements along with their respective screening levels. Emission factors for boron and fluoride were not available for wood, however because only natural (untreated) wood is permitted as the main fuel for this facility, there are not expected to be significant emissions of either of these elements. Therefore the air pollution emissions from the Facility will not adversely affect soil quality.

Table 6-10: Trace Element Emission Assessment					
Element	**Potential Emissions (Tons per Year)[1]**	**Estimated emission rate (g/s)**	**Estimated Maximum Annual Concentration (μg/m³)**	**Estimated Soil Concentration from Deposition DC (ppmw)**	**Screening Level [2] (ppmw)**
Arsenic	0.008	2.34E-04	1.06E-04	0.030	3
Boron	N/A				0.5
Cadmium	0.008	2.40E-04	1.09E-04	0.031	2.5
Chromium	0.043	1.23E-03	5.58E-04	0.160	8.4
Copper	0.100	2.87E-03	1.30E-03	0.373	40
Fluoride	N/A				400
Lead	0.098	2.81E-03	1.27E-03	0.365	1000
Manganese	0.175	5.03E-03	2.28E-03	0.655	2.5
Mercury	0.007	2.05E-04	9.29E-05	0.027	455
Nickel	0.067	1.93E-03	8.76E-04	0.251	500
Selenium	0.006	1.76E-04	7.97E-05	0.023	13
Vanadium	0.002	5.73E-05	2.60E-05	0.007	2.5

[1] Based on maximum potential emissions.
[2] Table 3.4 lists the screening level of the concentration of the element in the soil - *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, 1980).

6.5.4 Visibility Analysis

§5-502(4)(d) of the *Regulations* requires the evaluation of major sources and major modifications to demonstrate that the increase in allowable emissions will not cause an adverse impact on visibility in any sensitive area. The *Regulations* further define sensitive area as any portion of the area comprising Lye Brook Wilderness Area and all other terrain in Vermont at or above the elevation of 2500 feet above mean sea level. Section 6.4.2 of this document contains the review of visibility impairment for the Lye Brook Wilderness Area.

The nearest sensitive area to the Facility is Mount Ascutney located in Ascutney State Park. To help establish if the proposed Facility will cause an adverse impact on the visibility from the summit of Mount Ascutney, a Level 1 screening analysis using VISCREEN was conducted, and the results exceeded the screening criteria. Subsequently a Level 2 screening analysis was conducted. Since there is complex terrain between the Facility and Mount Ascutney containing some terrain features that are higher in elevation than the plume height, the atmospheric stability class was selected as ‘E’ instead of ‘F’ to represent that there will be some disruption of the plume. The model was run using two different wind speeds to help determine the worst case impacts. Table 6-11 has a summary of the results for the Level 2 screening. Based on the results of the Level 2 screening, the Facility will not cause an adverse impact and further analysis is not required.

Table 6-11: Sensitive Area Visibility Modeling Results								
Maximum Visual Impacts Inside the Sensitive Area								
					Delta-E		Absolute Contrast	
Background	Theta (°)	Azimuth (°)	Distance (km)	Alpha (°)	Screening Criteria	Plume	Screening Criteria	Plume
SKY	10	46	12.3	123	2.00	0.697	0.05	-0.004
SKY	140	46	12.3	123	2.00	0.295	0.05	-0.000
TERRAIN	10	46	12.3	123	2.00	0.442	0.05	0.002
TERRAIN	140	46	12.3	123	2.00	0.159	0.05	0.004
Maximum Visual Impacts Outside the Sensitive Area								
SKY	10	1	1.0	168	2.00	1.280	0.05	-0.016
SKY	140	1	1.0	168	2.00	0.753	0.05	0.004
TERRAIN	10	1	1.0	168	2.00	1.827	0.05	0.021
TERRAIN	140	1	1.0	168	2.00	0.673	0.05	0.025

7.0 HAZARDOUS AIR CONTAMINANTS

Emissions of hazardous compounds into the air are regulated under both state and federal regulations. Federal regulations are promulgated under 40 CFR Part 63 and use the terms "Hazardous Air Pollutants (HAPs)", "Major Source of HAPs", and "Area Source of HAPs". These regulations are specific to source emission categories, such as boilers, reciprocating engines, or chrome plating operations. Typically separate emission standards are established for Major Sources and Area Sources. The proposed Facility is not considered a Major Source of HAPs and is instead classified as an Area Source. The applicable federal regulations for HAPs were discussed above in Section 4.2. Vermont regulates emissions of hazardous air contaminants ("HACs") under to §5-261 of the Regulations. This regulation is pollutant specific rather than emission category specific. The Owner/Operator of a source must quantify its facility wide emissions of each HAC regulated by this rule. Any Facility whose emission rate of a HAC exceeds its respective Action Level ("AL") is subject to the rule for that respective HAC. 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.

As shown in Section 3.2, the facility is expected to exceed the action level of 35 different HACs and is therefore subject to §5-261.

For the HMSER review, the HACs are divided up into several categories based on their emission control characteristics: (1) non-mercury metallic HACs; (2) organic HACs; (3) acid gases; (4) ammonia; and (5) CDD/CDF.

7.1. HMSER Selection – non-mercury metallic HACs

The non-mercury metallic HACs that are estimated to exceed their respective action level include: arsenic, barium, beryllium, cadmium, chromium (total), chromium (hexavalent), cobalt, copper (dusts & mists), iron oxides (dusts & fumes), lead compounds, manganese, nickel compounds, vanadium pentoxide and zinc oxide.

Non-mercury metallic HACs are a component of the PM contained in the fly ash from the boiler. The choice of control devices for non-mercury metallic HACs is the same as those for fine PM.

The Agency is establishing HMSER for non-mercury metallic HACs from the Boiler as the use of a fabric filter control device and a filterable PM emission limit of 0.010 lb/MMBtu (1 hour block average). The single filterable PM emission limit is serving as a surrogate for separate emission limits for each of these numerous non-mercury metallic HACs from the boiler.

7.2. HMSER Selection – organic HACs

The Facility's organic HAC emissions that are estimated to exceed their respective action level include: 1,2-dichloroethane (ethylene dichloride), 1,2-dichloropropane (propylene dichloride), acetaldehyde, acrolein, benzene, benzo(a)pyrene, bromodichloromethane, chloroform, dichloromethane (methylene chloride), dinitrotoluene-2,4, formaldehyde, hexachlorobenzene, naphthalene, tetrachloroethylene (perchloroethylene), trichloroethylene, and vinyl chloride.

These organic emissions are formed by incomplete combustion of fuel. The methods for control of organic HACs from the Boiler would be the same as for the control of VOCs. Thus total VOC emissions or CO can reasonable serve as a surrogate to demonstrate adequate control of the individual organic HACs.

HMSER for organic HACs is good combustion control and the use of a BFB, and a CO emission limit of 0.075 lb/MMBtu (24 hour rolling average), and a VOC emission limit of 0.005 lb/MMBtu (hourly average).

7.3. Acid Gases

Sulfuric acid mist, hydrogen chloride and chlorine are estimated to exceed their respective action level.

Sulfur that is present in fuels is converted during combustion to SO_2 and to a lesser degree SO_3. The SO_3 rapidly reacts with the water vapor in the exhaust gases to form H_2SO_4 (sulfuric acid mist). Some of the chlorine that is present in the wood fuel may also be released from the chemical composition of the wood and a portion of this may be released as chlorine, but it is more likely to form hydrochloric acid.

Add-on control technologies that are available to reduce acid gas emissions include dry sorbent injection, wet scrubbing systems and spray dryer adsorbers. These control technologies were reviewed in Section 5.4 above for the control of SO_2 and were determined to not be cost effective for SO_2, with the lower emission rate of sulfuric acid mist, the cost of control would be even higher.

HMSER for the Boiler is the use of natural wood which has an inherently low level of sulfur and chlorine, and a HCl emission limit of 0.000834 lb/MMBtu.

7.4. Ammonia

Ammonia is used as a reagent in the SCR unit of the boiler to react with NO_X to form nitrogen and water. Some of the ammonia will pass through the SCR unreacted and be emitted with the exhaust gas. This is referred to as ammonia slip. Ammonia slip is minimized through good controls of the ammonia feed system and the use of an ammonia CEMS. A review of ammonia emission limits for other wood fired boilers equipped with SCR systems for NOx control show that the lowest limit is 10 ppm NH_3 @ 7% O_2 (this is essentially the same as 13 ppm NH_3 @ 3% O_2).

The Permittee has proposed an HMSER of 10 ppm NH_3 @ 7% O_2.

The Agency concurs with this proposed limit and is establishing HMSER as an ammonia slip limit of 10 ppm NH_3 @ 7% O_2 based on a 24-hour rolling average for the wood fired boiler.

7.5. CDD/CDF

In combustion processes, CDDs and CDFs can be formed from the thermal breakdown of precursor ring compounds and chlorine. These precursor compounds are produced as a result of incomplete combustion. According to the EPA, dioxin formation occurs between 392 and 842^{o}F. Typical control is using fuels with low chlorine content and through the use of good combustion design and combustion practices to minimize the formation of the precursors.

In municipal incinerators, which have higher levels of chlorine in the fuels and therefore greater CDD/CDF emission rates, controls have also included the injection of powdered activated carbon (PAC) into the exhaust gas. The gaseous CDD/CDFs are absorbed onto the activated carbon, and carbon can be removed from the exhaust gases with a traditional PM control device (ESP or fabric filter). For this approach to be the most effective it must be located at a point in the exhaust system where the exhaust temperatures are lower than the dioxin formation range (less than ~ 400^{o}F). This would require a PAC system on this Facility's boiler to be located downstream of the SCR, which would necessitate a second PM control device to remove the carbon.

The Permittee is proposing HMSER for CDD/CDFs to be good combustion practices and properly operated air pollution control equipment.

The Agency agrees that HMSER for CDD/CDFs is good combustion practices and properly operated air pollution control equipment.