COMMONWEALTH OF MASSACHUSETTS
EXECUTIVE OFFICE OF ENERGY & ENVIRONMENTAL AFFAIRS
DEPARTMENT OF ENVIRONMENTAL PROTECTION
WESTERN REGIONAL OFFICE
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Lieutenant Governor

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December 31, 2010

Matthew A. Palmer, PE
Pioneer Valley Energy Center, LLC
75 Arlington Street, Suite 704
Boston, Massachusetts 02116

Re: PVAPCD – Westfield
Regulation 310 CMR 7.02(5)(a)
Pioneer Valley Energy Center
Appl. #1-B-08-037; Trans. #X223780
431 MW Combined Cycle Power Plant

Conditional Approval to Construct

Dear Mr. Palmer:

The Department of Environmental Protection, Western Regional Office ("MassDEP") received on December 9, 2008 a Major Comprehensive Plan Application from the Westfield Land Development Company, LLC [1] for the installation and operation of a new 431 megawatt ("MW") combined cycle combustion turbine power generating facility designated as the Pioneer Valley Energy Center ("PVEC" or "Facility"). The plans bear the seal and signature of Eric A. Pearson, Massachusetts Registered Professional Engineer No. 39741.

The application has been reviewed by MassDEP, and MassDEP is of the opinion that the combined cycle power plant proposed by PVEC is consistent with modern air pollution control technology, BACT, and LAER. The MassDEP hereby proposes to grant an Approval to Construct for the equipment described herein and in the submittal pursuant to Regulation 310 CMR 7.02(5)(a) of the "Regulations for the Control of Air Pollution in the Pioneer Valley Air Pollution Control District"

[1] On May 28, 2009, the name of the organization was changed from the Westfield Land Development Company, LLC to the Pioneer Valley Energy Center, LLC. To avoid possible confusion of names, all submittals made under the old organization name are referred in this document to as being made by PVEC.

This Approval is an action of MassDEP. If you are aggrieved by this action, you may request an adjudicatory hearing. A request for a hearing must be made in writing and postmarked within twenty-one (21) days of the date this approval letter was issued.

Under 310 CMR 1.01(6)(b), the request must state clearly and concisely the facts which are the grounds for the request and the relief sought.

The hearing request along with a valid check payable to the Commonwealth of Massachusetts in the amount of one hundred dollars ($100) must be mailed to:

Commonwealth of Massachusetts
Department of Environmental Protection
P. O. Box 4062
Boston, MA 02211

The request will be dismissed if the filing fee is not paid, unless the appellant is exempt or granted a waiver as described below.

The filing fee is not required if the appellant is a city or town (or municipal agency), county, or district of the Commonwealth of Massachusetts, or a municipal housing authority.

MassDEP may waive the adjudicatory hearing filing fee for a person who shows that paying the fee will create an undue financial hardship. A person seeking a waiver must file, together with the hearing request as provided above, an affidavit setting forth the facts believed to support the claim of undue financial hardship.

This Approval consists of the application materials and this Approval letter. If conflicting information is found between these two documents, then the requirements of the Approval letter shall take precedence over the documentation in the application materials.

This Approval pertains only to the air quality control aspect of the proposal and does not negate the responsibility of the owners or operators to comply with other applicable state, local, or federal laws and regulations.

If you have any questions regarding this Approval, please do not hesitate to contact Marc Simpson of the Western Regional Office at (413) 755-2115.

Sincerely,

This final document copy is being provided to you electronically by the Department of Environmental Protection. A signed copy of this document is on file at the DEP office listed on the letterhead.

Michael Gorski
Regional Director
Department of Environmental Protection
Western Region

PVEC 2010-12-31 FINAL.doc
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I. Introduction

The Facility is subject to the requirements of the Massachusetts Environmental Policy Act (MEPA) Massachusetts General Laws (M.G.L.) Chapter 30, Sections 61-62H. On March 6, 2009, the Secretary of the Executive Office of Energy & Environmental Affairs ("EOEEA") issued a certificate that the Final Environmental Impact Report (FEIR – EOEEA #14151) adequately complied with the MEPA and its implementing regulations.

On October 19, 2009, the Energy Facilities Siting Board ("EFSB") issued a Final Decision under M.G.L. Chapter 164, §69J approving PVEC's Petition to construct and operate the Facility. In accordance with that statute and the EFSB's Final Decision, MassDEP has issued this Approval to Construct for the Facility, incorporating the relevant provisions of the EFSB approval that pertain to air quality.

Effective March 3, 2003, the MassDEP returned delegation of the federal Prevention of Significant Deterioration ("PSD") program to the United States Environmental Protection Agency ("USEPA"). Consequently, as of that date, sources of air pollution in the Commonwealth of Massachusetts that are subject to the Federal PSD program must apply for and receive a federal PSD permit from the USEPA–Region 1 before beginning actual construction.

PVEC submitted to the EPA on November 24, 2008 a PSD Permit application. EPA issued a draft PSD permit for public comment on November 5, 2010. This MassDEP Approval to Construct incorporates the relevant provisions of approval contained in that draft PSD permit.

PVEC has potential emissions that exceed the applicability thresholds specified in MassDEP's Nonattainment Review ("NA") Regulations at 310 CMR 7.00, Appendix A. This Approval To Construct was subject to a public comment period and a public hearing as specified in the Commonwealth's Air Pollution Control Regulations at 310 CMR 7.00: Appendix A.

A Public Notice was published in the Westfield Evening News and in the Springfield Republican on May 17, 2010 providing notification of a public hearing to be held on June 16, 2010 at the Westfield North Middle School. At the hearing, both oral and written public comments were received. The public comment period closed 10 days after the public hearing. A summary of the public comments and the MassDEP response has been issued as a separate document.

II. Facility Description

The proposed plant site is located in an industrial land-use area of Westfield, Massachusetts bounded by Servistar Industrial Way toward the south and east, Ampad Road toward the west, and an undeveloped wooded area toward the north.

The Facility will consist of a Mitsubishi M501G air-cooled combustion turbine/generator (“CTG”) and heat recovery steam generator (“HRSG”) that will supply high pressure superheated steam to a steam turbine generator.

The combustion turbine will fire natural gas as a primary fuel and ultra low sulfur distillate (“ULSD”) oil as backup. An alternative backup fuel that may be used will be 100% biodiesel or a blend of ULSD/biodiesel.[2] The combustion turbine will have a maximum heat input rate of 2,542 million British thermal units (LHV) per hour (MMBtu/hr) and a maximum gross power output (including the steam turbine) of 431 MW while firing natural gas. The maximum heat input rate and gross power output will be approximately 2,016 MMBtu/hr and 306 MW, respectively, while firing ULSD. The exact heat input and power output rates using biodiesel oil have not yet been specified by the turbine manufacturer.

The combustion turbine will be equipped with a Selective Catalytic Reduction (SCR) emissions control system to minimize emissions of nitrogen oxides (NO_x) and an oxidation catalyst to minimize emissions of carbon monoxide (CO) and volatile organic compounds (VOC). Sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4), and particulate ($PM/PM_{10}/PM_{2.5}$) emissions will be minimized through the use of clean burning fuels (natural gas and ULSD/Biodiesel). Exhaust gases from the combustion turbine will be discharged through an exhaust stack 23 feet in diameter and 180 feet tall.

There will also be an auxiliary boiler and an emergency generator associated with the Facility that will be housed within the main plant building. The auxiliary boiler will have a maximum heat input rate of approximately 21 MMBtu/hr and will be fired by natural gas. Exhaust gases from the auxiliary boiler will be discharged through an exhaust stack 2 feet in diameter and 125 feet tall. The auxiliary boiler will be limited to no more than the fuel use equivalent (at maximum firing rate) of 1,100 hours of operation per rolling 12-month period.

The diesel-powered emergency generator will have a power output of approximately 2,174 horsepower (hp) and 1500 KWe-shaft. A separate, small building located to the north of the main plant building will contain a 270-hp diesel-powered emergency fire water pump system. Both the emergency generator and the diesel powered emergency fire pump will fire ULSD/Biodiesel fuel and each will be equipped with a non-resettable hour meter.

The emergency generator and fire pump will each be limited to no more than 300 hours of operation per rolling 12-month period. The diesel generator and fire pump will not

[2] Hereafter, any reference to the use of ULSD oil, 100% biodiesel oil, or a ULSD/biodiesel oil blend will be simply referred to as "ULSD/Biodiesel".

operate concurrently with the combustion turbine other than one hour per week for maintenance and testing, which will only occur between the hours of 8 am and 5 pm. The Facility will also include a mechanical draft wet cooling tower equipped with drift eliminators, an electrical switchyard, and on-site tanks for the storage of ULSD / Biodiesel along with water and aqueous ammonia ($NH_{3}(aq)$) used by the combustion turbine's emissions control system. Other pieces of support equipment located outside the building will include an auxiliary lube-oil cooling system, water purification systems, and a fuel gas compressor and metering station.

The combustion turbine will be permitted for unrestricted operation on natural gas and for up to the fuel use equivalent (at maximum firing rate) of 1,440 hours per year of operation on ULSD/Biodiesel. Consistent with the EFSB Final Decision, operation on ULSD/Biodiesel will be limited to the fuel use equivalent (at maximum firing rate) of no more than 46 days from January 1st to November 30th (and not during ozone season), with at least 14 days of operation reserved for December 1st to December 31st. Consistent with the EPA draft PSD permit No. 052-042-MA14 issued November 5, 2010, operation on ULSD/Biodiesel will only occur during hours when the interruptible natural gas supply is curtailed, or other special operating conditions exist, as detailed in the provisions of this Approval to Construct.

Potential emissions from the facility will be as depicted in Table 1, as follows:

Table 1
Facility Potential Emissions (tons per year)

Pollutant	Combustion Turbine (8,215 hr/yr)	Auxiliary Boiler (1,100 hr/yr)	Emergency Generator (300 hr/yr)	Fire Pump (300 hr/yr)	PTE - Normal Operation(1)	CT Startup/ Shutdown(2) (545 hr/yr)	Facility PTE(3)	Sig. Emission Rates		PSD?	NA?
								PSD	NA		
NO_x	91.9	0.3	5.6	0.5	98.4	12.6	110.9	40	50	yes	yes
CO	59.9	0.4	1.8	0.3	62.5	487.4	549.9	100		yes	
SO_2	16.7	0.0	0.5	0.1	17.2	0.8	18.0	40		no	
H_2SO_4	17.2	0.0	0.0	0.0	17.2	0.8	18.0	7.0		yes	
$PM/PM_{10}/PM_{2.5}$ (Total)	49.1	0.1	0.1	0.0	49.4	1.7	51.0	25 PM 15 PM_{10}		yes	
$PM/PM_{10}/PM_{2.5}$ (Filterable)	24.6	0.0	0.1	0.0	24.7	0.8	25.5				
$PM/PM_{10}/PM_{2.5}$ (Condensible)	24.6	0.0	0.1	0.0	24.7	0.8	25.5				
NH_3	27.3	0.0	0.0	0.0	27.3	1.4	28.8				
VOC	23.8	0.0	0.3	0.1	24.2	0.6	24.8	40	50	no	no
Lead	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6		no	
Formaldehyde	2.5	0.0	0.0	0.0	2.5	0.1	2.6				
Total HAPS	5.1	0.0	0.0	0.0	5.1	0.2	5.3				

(1) Total emissions represent maximum potential of all equipment operating independently, and are based on the operation of the combustion turbine for 8,215 hr/yr, the auxiliary boiler for 1,100 hr/yr, the emergency generator and fire pump for 300 hr/yr each, and on 545 hr/yr spent in startup or shutdown.

The combustion turbine may operate up to 8,760 hours per year, resulting in decreased startup and shutdown hours and overall emissions. Startup and shutdown operation may exceed 545 hours per year, provided that the “Facility PTE” annual emission limits are not exceeded.

(2) Startup/shutdown emissions are estimated based on 141 warm starts (2.0 hours each), 35 cold starts (5.0 hours each), and 176 shutdowns (1.0 hours each).

Cold startups are defined as occurring after a period of greater than 24 hours of turbine shutdown.

Warm startups are defined as occurring after 24 hours or less since turbine shutdown.

Shutdown is defined as the time when the turbine operation is between minimum sustained operating load and flame-out in the turbine combustor occurs.

(3) The Facility PTE is the sum of the PTE during normal operation and during startup/shutdown of the combustion turbine.

III. Regulatory Applicability

MassDEP Major Comprehensive Plan Approval

MassDEP's regulations specify that all projects are required to implement Best Available Control Technology (BACT) to minimize air emissions and to demonstrate that the project will not cause or contribute to an exceedance of state or national ambient air quality standards. MassDEP also requires all projects to demonstrate compliance with the state's noise policy.

MassDEP Nonattainment Review

The Facility is located in a moderate non-attainment area for ozone. The Facility's potential NO_x emissions (a precursor to ozone) exceed the major source threshold of 50 tons per year. Therefore, the Facility is subject to review under MassDEP's Non-attainment Review (310 CMR 7.00, Appendix A), which requires the Facility to implement Lowest Achievable Emission Rate (LAER) for the NO_x emissions from the combustion turbine.

Additionally, the total annual NO_x emissions from the Facility must be offset by an equal or greater reduction in the actual emissions of NO_x from other sources. The ratio of total actual emission reductions to the increase in actual emissions must be at least 1.26:1 (a 1.2:1 offset ratio coupled with a 5% public benefit set aside). All offsets used must be federally enforceable. PVEC has acquired Emission Reduction Credits ("ERCs") in the required ratio from NSTAR Electric and Gas Corporation, One NSTAR Way, Westwood, MA 02090, and from Osram Sylvania Products, Inc., 100 Endicott Street, Danvers, MA 01923 to fully offset the Facility's NO_x emissions prior to receiving this Plan Approval from MassDEP.

EPA Prevention of Significant Deterioration

The Facility is located in an area that is in attainment for all pollutants except ozone. The Facility's potential NO_2 emissions exceed the PSD applicability threshold of 100 tons per year. Therefore, the PSD regulations (40 CFR Part 52.21) apply to the Facility and require the application of BACT for all attainment pollutants with potential emissions above the Significance Emission Rates defined in the PSD regulations (NO_2, CO, PM, PM_{10}, $PM_{2.5}$ and H_2SO_4). PVEC submitted a PSD application to the EPA on November 24, 2008.

The PSD program also requires a source impact analysis to demonstrate that allowable emission increases from the proposed source, in conjunction with all other applicable emissions increases or reductions would not cause or contribute to air pollution in violation of any NAAQS or any applicable maximum allowable increase over the existing background concentration in any area.

The results of the air impact analysis demonstrate that the impacts from the Facility are below the Significant Impact Levels (SILs) established by the EPA. PVEC requested a waiver from the EPA from the pre-construction ambient air monitoring requirements of the PSD Program, as the impacts from the Facility have been demonstrated to be insignificant, as defined by the EPA. PVEC filed an application with the USEPA for a PSD Permit on November 24, 2008 that included a request for waiver from preconstruction monitoring.

EPA issued a draft PSD permit for public comment on November 5, 2010. This MassDEP "Approval to Construct" incorporates the relevant portions of that draft permit.

EPA Acid Rain Permit

The combustion turbine will be designated as a Phase II New Affected Unit under the federal Acid Rain Program, 40 CFR Part 72 & 75. The Acid Rain Program requires all affected units to establish a compliance account and hold allowances not less than the total annual emissions of SO_2 from the previous calendar year.

PVEC will certify a designated representative, and submit a complete Acid Rain permit application to the EPA at least 24 months before commencing operation. PVEC will establish a compliance account and obtain allowances for its annual SO_2 emissions. PVEC will meet all of the applicable certification, monitoring, recordkeeping, and reporting requirements of the Acid Rain Program by the established compliance deadlines, in accordance with 40 CFR Parts 72 and 75.

EPA New Source Performance Standards

Combustion Turbine

The combustion turbine is subject to NSPS Subpart KKKK - Standards of Performance for Stationary Combustion Turbines.

PVEC will demonstrate compliance with the Subpart KKKK SO_2 emission standard by conducting sulfur analyses on the natural gas and ULSD/Biodiesel fuels in accordance with the requirements of the NSPS. PVEC will submit reports of excess emissions and monitor downtime in accordance with the NSPS. Excess emissions will be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

PVEC will demonstrate compliance with the Subpart KKKK NOx emission standard by the use of a certified continuous emissions monitoring system (CEMS) to be installed on the turbine stack. The NOx CEMS will be certified, operated, and maintained in accordance with the applicable requirements of the NSPS and 40 CFR 60, Appendix B, Performance Specification 2, "Specifications and Test Procedures for SO_2 and NOx Continuous Emission Monitoring Systems in Stationary Sources."

Auxiliary Boiler

Steam generating units with a design heat input capacity > 10 MMBtu – ≤ 100 MMBtu per hour that commence construction after June 9, 1989 are subject to the requirements of 40 CFR 60, Subpart Dc, "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units." The SO_2 and PM emission standards contained in Subpart Dc do not apply to affected units that fire natural gas, such as the proposed auxiliary boiler.

To comply with Subpart Dc, an initial notification will be submitted, indicating the date of construction and startup, the boiler's design heat capacity, and the fuel to be fired. Records will be kept of the amount of fuel combusted by the boiler during each day of operation.

Emergency Engine & Diesel Fire Pump

Stationary compression-ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, that are manufactured after April 8, 2006, and are not fire pump engines, must meet the requirements of 40 CFR 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines." Subpart IIII also applies to certified National Fire Protection Association (NFPA) fire pump engines that are manufactured after July 1, 2006, and commence construction after July 11, 2005. Both the emergency diesel engine/generator set and the diesel fire pump proposed for the Facility will be subject to this NSPS.

Owners and operators of 2007 model year or later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kW and a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new non-road CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007. For new non-road CI engines with a model year after 2006 with a maximum engine power greater than 560 kW, the Tier 2 emission standards listed in 40 CFR 89.112, Table 1 apply. Fire pump engines must comply with the emission standards listed in Table 4 of the NSPS.

The diesel fuel fired by both the emergency generator and the fire pump must meet the requirements of 40 CFR 80.510(a), which limits the sulfur content to 500 ppm or less. Beginning October 1, 2010, the fuel requirements of 40 CFR 80.510(b) must be met, which limits fuel sulfur content to 15 ppm or less.

The emergency diesel engine/generator set to be selected for the Facility will be certified by the manufacturer to meet the applicable emissions standards set forth at 40 CFR 89.112, Table 1, for Tier 2 engines. The fire pump will be certified to meet the applicable emission standards set forth in Table 4 of the regulation.

Records will be kept of the operation of the diesel generator and fire pump, and of all non-emergency service that are recorded by the non-resettable hour meters. An initial notification will not be required for the emergency generator or fire pump, nor will there be any additional record keeping or reporting required to comply with the NSPS.

EPA National Emission Standards for Hazardous Air Pollutants

The 1990 Clean Air Act Amendments (CAAA) includes a list of 188 Hazardous Air Pollutants (HAPs). HAPs include organic compounds and trace metals for which the EPA has not established ambient air quality standards, except for lead (Pb) for which the EPA has established NAAQS. HAPs are regulated by the EPA under NESHAPS.

The EPA promulgated NESHAPS for combustion turbines on March 5, 2004 (40 CFR Part 63, Subpart YYYY). Under Subpart YYYY, an affected source includes new or reconstructed turbines approved to fire more than 1000 hours per year of oil located at a major HAP source. A major HAP source is a source with a potential to emit 10 tpy or more of any single HAP, or 25 tpy or more of all HAPs combined. The new power generating facility will be a minor source of HAPs so there are no NESHAPS requirements applicable to the new combustion turbine.

Part 63 Subpart ZZZZ for engines
The EPA promulgated NESHAPS for stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions on March 10, 2010 (40 CFR Part 63, Subpart ZZZZ). Under Subpart ZZZZ, the emergency diesel generator and fire pump proposed for the PVEC facility will meet the Subpart ZZZZ criteria as new stationary RICE located at an area source of HAP emissions, and will therefore be designated as affected sources under 40 CFR 63, Subpart ZZZZ.

According to §63.6590(c), an affected source that is a new or reconstructed stationary RICE located at an area source must meet the requirements of Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII (compression-ignition engines) or 40 CFR 60, Subpart JJJJ (spark-ignition engines), with no further requirements applying to such engines. The PVEC standby engines, which are compression-ignition engines, will therefore comply with 40 CFR 63, Subpart ZZZZ by meeting the applicable requirements of 40 CFR 60, Subpart IIII, as described in the section of this approval titled **EPA New Source Performance Standards**.

MassDEP Industry Performance Standards
The regulations at 310 CMR 7.26(30) through (37) establish performance standards for boilers installed on or after September 14, 2001 with a heat input rating of ≥ 10 MMBtu – < 40 MMBtu per hour. Although the auxiliary boiler proposed for the Facility has a maximum heat input rating of approximately 21 MMBtu per hour, which falls within the applicability range of the Performance Standards, the regulations do not apply to units located at facilities required to obtain an Operating Permit.

The regulations at 310 CMR 7.26(40) through (44) apply to engines and combustion turbines installed on and after March 23, 2006 that are not subject to PSD or NANSR review. The combustion turbine proposed by PVEC is subject to PSD and NANSR review, and therefore is not subject to the MassDEP Industry Performance Standards.

Regional Greenhouse Gas Initiative
Massachusetts has established the Carbon Dioxide Budget Trading Program (310 CMR 7.70) to implement the Regional Greenhouse Gas Initiative (RGGI) to reduce greenhouse gas emissions (GHG) from power plants. The nine-state regional agreement, which was signed by Massachusetts in January of 2007, establishes a market-based “cap-and-trade” auction system that requires major power plants to obtain allowances to cover the amount of their carbon emissions. Regulation 310 CMR 7.70 creates a regulatory structure for incentives and penalties designed to reduce carbon emissions statewide. PVEC is subject to Regulation 310 CMR 7.70(1)(d) because, when constructed, it will be a source with a unit serving an electricity generator with a nameplate capacity equal to or greater than 25 MWe.

To satisfy the requirements of the CO_2 Budget Trading Program, PVEC will:

- Designate a CO_2 authorized account representative and submit a completed account certificate of representation to MassDEP.

- Submit to MassDEP a CO_2 budget emission control plan ("ECP") at least twelve months before commencing operation.
- Operate the Facility in compliance with the approved ECP.
- Comply with the monitoring, certification, recordkeeping, and reporting requirements of 310 C.M.R. § 7.70(8).
- Hold allowances in an amount not less than the total CO_2 emissions for each three calendar year control period.
- Submit a compliance certification report to MassDEP by March 1st following each control period.

MEPA Greenhouse Gas Emissions Policy and Protocol

The Massachusetts Executive Office of Energy and Environmental Affairs (EOEEA) has established a Massachusetts Environmental Policy Act (MEPA) Greenhouse Gas Emissions Policy and Protocol, which requires specified projects undergoing review by the MEPA Office to quantify their greenhouse gas (GHG) emissions and identify measures to avoid, minimize, or mitigate those emissions.

The Policy applies to new projects that file an Environmental Notification Form (ENF) for MEPA review after October 15, 2007. A project is subject to the Policy if an EIR is required, and it falls into at least one of the following categories:

- MEPA has full scope jurisdiction or equivalent full scope jurisdiction over the project;
- The Project is privately funded and requires an Air Quality Permit from MassDEP;
- The Project is privately funded and requires a Vehicular Access Permit from the Mass Highway Department.

PVEC submitted an ENF to MEPA for the Facility on November 30, 2007. The MEPA Office issued an ENF Certificate for the Facility on January 23, 2008, which outlined the specific requirements for the Facility to comply with the GHG Policy.

PVEC submitted a Draft Environmental Impact Report (DEIR) to the MEPA Office for the Facility on August 15, 2008. The DEIR included a project GHG emissions baseline consisting of the direct CO_2 emissions from stationary sources, as well as the indirect CO_2 emissions from mobile sources associated with the operation of the Facility. The DEIR also included an alternatives analysis.

The MEPA Office issued a Certificate on the DEIR for the Facility on October 17, 2008, which included recommendations on revisions to the GHG analysis for the Facility. These revisions were presented in PVEC's Final Environmental Impact Report (FEIR), based upon the guidance of the MassDEP comment letter on the DEIR.

PVEC filed an FEIR with the EOEEA that fully addressed the recommendations regarding compliance with the MEPA GHG Policy contained in the DEIR Certificate for the Facility. The FEIR included a commitment to specific design and operational GHG mitigation measures, and the GHG emission reductions associated with those measures were quantified. The FEIR included an expanded analysis on the potential technical challenges associated with the use of bio-fuels at the Facility, including the viability of using bio-fuels for the less fuel-consuming equipment, and a future commitment to the use of bio-fuels, contingent on adequate supply, where it is technologically feasible. The FEIR also included a proposal for a range of near-term and future on-site and off-site commitments to mitigate GHG emissions and support local energy efficiency and conservation efforts, as well as any future developments these commitments may require.

Hydropower generation project
PVEC has committed to implementing an innovative, small-scale hydropower generation project to mitigate greenhouse gas impact resulting from development of the PVEC Facility. PVEC proposed a system to be located on the water supply line to the cooling tower and utilize the potential hydraulic energy available in the flow of water supplied to the facility.

Three variables will determine the potential hydropower that this turbine can produce. The calculation of potential facility power based on these variables indicates:

- The volumetric flow rate based on peak flow operation (2.0 million gallons per day) is 3.094 cubic feet per second.
- The static head, considering the elevation of the reservoir spillway and the PVEC Facility, is 212 feet (ft).
- The available head, considering frictional head loss, ranges from 131 ft to 169 ft.
- Using a Cornell Hydraulic Energy Recovery Turbine, the calculated power output based on the size of the water supply line, volumetric flow rate, available head and combined turbine and generator efficiency is 25 kilowatts (kW) to 32 kW.

Source Registration

The MassDEP Source Registration requirements (310 CMR 7.12) apply to all fuel utilization facilities that fire natural gas with a maximum energy input capacity equal to or greater than 10 MMBtu/hr. PVEC will submit to the MassDEP a Source Registration, signed by the designated Responsible Official, by April 15th of each year.

MassDEP Noise Policy

The MassDEP noise guideline, as found in 310 CMR 7.10 and MassDEP Policy 90-001, states that a new noise source may not exceed the existing quietest ambient L_{90} noise level by more than 10 dBA. In addition, noise levels in any single octave band may not exceed the noise levels in both of the adjacent octave bands by more than 3 decibels.

MassDEP’s noise criteria limits are generally applied to both the nearest inhabited buildings and the site’s property lines. The analysis conducted for the Facility indicates that with the proposed noise mitigation, PVEC will comply with the MassDEP noise policy at all residential locations, and at three (PL-2, PL-4, and PL-5) of the five property line locations. PVEC has obtained releases from the abutting industrial property owners at one of the property line receptor locations (PL-1) with modeled sound impacts that exceed the levels allowed by the MassDEP policy. No release was sought at PL-3 since that location, coinciding with a power line right-of-way, is not buildable and not a potential sensitive receptor. No additional releases will be required for the Facility to comply with the MassDEP Noise Policy.

Risk Management Program

Because SCR will be employed to control NO_x emissions from the CTG/HRSG, it will be necessary to store NH_3(aq) on-site. The proposed CTG/HRSG will use NH_3(aq) at concentrations of less than 19.5% and thus the NH_3 storage facilities will not be subject to the EPA's Accidental Release Program under 40 CFR Part 68. However, the provisions of Section 112(r) of the Clean Air Act include a "general duty clause" that requires such facilities to be designed and operated in a manner that prevents the release of NH_3 and that minimizes the consequences of an accidental release.

The NH_3(aq) will be stored in an above-ground 20,000 gallon tank. The tank will be situated within a concrete bermed area which is able to contain 110% of the volume of the tank. To minimize evaporation In the event of a spill into the bermed area, passive evaporative controls (plastic balls) will be installed to reduce the surface area by 90%.

A worst-case accidental release scenario was performed to evaluate the potential health impacts at the nearest public receptor of a release of the entire contents of the tank into the surrounding concrete berm.

The American Industrial Hygiene Association has developed Emergency Response Planning Guidelines (ERPGs) for NH_3 and other substances. The ERPG-2 represents the concentration below which it is believed nearly all individuals could be exposed for up to one hour without irreversible or serious health effects. The ERPG-2 for NH_3 is 200 ppm. EPA has adopted the ERPG-2 as the toxic endpoint for NH_3 for the offsite consequence analysis.

The emissions and impacts of the hypothetical worst-case release scenario were based on the ALOHA model (Areal Locations of Hazardous Atmospheres) which is included as a prescribed technique under the EPA Risk Management Plan Guidance. The results of the ALOHA Model indicate that in the event of a hypothetical worst-case release, the NH_3 concentration at the closest public receptor, the industrial building located to the southwest of the Facility, would not exceed the ERPG-2 level of 200 ppm.

Therefore, the storage of NH_3(aq) at the PVEC site would not cause any permanent adverse health impacts at the nearest public receptor even in the event of a worst-case NH_3(aq) release.

IV. Proposed Emission Controls

PVEC must implement LAER controls for NOx and BACT controls for all other pollutants. PVEC will utilize the emission controls depicted in Table 2 and Table 3, as follows:

Table 2
LAER Emission Controls

Emission Unit	LAER FOR NOx
CTG	• Dry low-NOx combustors while firing natural gas; • Water injection to reduce NOx emissions while firing ULSD/Biodiesel; • SCR to reduce NOx emissions

Table 3
BACT Emission Controls

Emission Unit	BACT for SO_2/H_2SO_4, $PM/PM_{10}/PM_{2.5}$, CO / VOC, and NH_3
CTG	• Oxidization catalyst to reduce CO and VOC emissions; • Using natural gas as the primary fuel with ULSD/Biodiesel as secondary fuels to minimize SO_2 and $PM/PM_{10}/PM_{2.5}$ emissions • Properly designed SCR and associated NH_3 injection system to minimize NH_3 slip from the SCR
Cooling Tower	• Mist eliminators to control PM_{10} emissions from the cooling tower

V. Control Technology Analysis – LAER & BACT

The MassDEP's regulations specify that an emission source with potential emissions that exceed the applicability thresholds specified in MassDEP's Nonattainment Review ("NA") Regulations at 310 CMR 7.00, Appendix A are required to implement a level of pollutant emission control at least equivalent to Lowest Achievable Emission Rate ("LAER") for those pollutants. LAER is defined by the EPA and MassDEP as the most stringent emission limitation contained in any State Implementation Plan (SIP) for a source category, or the most stringent emissions limitation which is achieved in practice for a source category.

The MassDEP's regulations also specify that an emission source requiring Plan Approval is required to implement a level of pollutant emission control at least equivalent to Best Available Control Technology ("BACT") to minimize air emissions. The determination of BACT is made through a "top-down" analysis of potentially viable control technologies starting with the approach that provides the greatest level of emission control.

To complete the BACT/LAER analysis for the proposed combustion turbine at the Facility, control technologies demonstrated in practice for similar sources, and corresponding emission limits established by various state agencies and the EPA were reviewed. BACT/LAER determinations listed in the USEPA RACT/BACT/LAER Clearinghouse (RBLC), the South Coast Air Quality Management District BACT determinations, the California Air Resources Board's BACT Clearinghouse Database, and any available recently issued air permits were also reviewed.

The review was limited to combustion turbines permitted since 2000 with an output greater than 200 MW fired on natural gas and/or distillate oil used in a combined-cycle power plant configuration.

LAER for NOx

As a major source of NO_x emissions located in a nonattainment area for ozone, the Facility is also required to implement the LAER for the NO_x emissions from the combustion turbine.

NO_x emissions from the combustion of fossil fuels is largely the result of fuel-bound nitrogen content of the fuel, prompt NOx formed at the flame front, and thermal NOx which is created in the high temperature flame zone.

Natural gas has negligible fuel-bound nitrogen, and ULSD/Biodiesel has the lowest levels of fuel bound nitrogen of any liquid fossil fuel. The majority of the NO_X formed from the combustion of natural gas and fuel oil is thermal.

Beyond the selection of low emitting fuels, several design and add-on technologies have been developed to minimize NO_x emissions, as follows:

Dry Low-NOx Combustors
In dry low-NO_x (DLN) burners, air and fuel are mixed before entering the combustor to provide more homogeneous charge. To achieve low NO_x emission levels, the mixture of fuel and air should be near the lean flammability limit of the mixture. However at reduced load conditions, lean premixed combustors may lead to some combustion instability and increased CO emissions. This technology will be utilized for the Facility.

Water Injection
Water injection involves injection of water or steam into the immediate vicinity of the combustor burner flame. Instantaneous cooling reduces the NO_x formation in the combustion chamber. However water or steam injection may also lead to increases in emissions of CO and hydrocarbons (HC) resulting from incomplete fuel combustion, and a heat rate penalty. Water injection will be utilized for the Facility only during ULSD/Biodiesel firing.

Selective Catalytic Reduction (SCR)
An SCR control system is a method for converting NO_x generated from the combustion turbine to N_2 and water by reaction with NH_3 in the presence of a catalyst. NH_3 is vaporized and injected in the flue gas upstream of the catalyst, which, when passing over the catalyst, results in the following dominant chemical reactions.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

NH_3 is added in slight excess in order to minimize the NOx emissions. The excess NH_3 that remains unreacted is emitted from the stack and is referred to as "ammonia slip". In this application, NH_3 slip is expected to be less than 2 ppm at 15% O_2 while firing either natural gas or ULSD/Biodiesel.

The SCR control system can also produce some additional PM_{10} emissions in the form of ammonium bisulfate compounds. By balancing the allowable NH_3 slip and the required catalyst necessary to achieve the required level of NOx control, the SCR system's contribution to the potential PM_{10} emissions of the proposed Facility is considered to be negligible. This technology will be utilized for the Facility.

According to the RBLC, there are numerous similar projects that have been permitted since the year 2000 with a stack concentration of 2.0 ppmvd NOx @ 15% O2 while firing natural gas and 5.0 ppmvd NOx @ 15% O_2 while firing ULSD oil. These levels of NOx emissions are LAER for the combustion turbine.

BACT for SO_2 / H_2SO_4
Emissions of SO_2 and H_2SO_4 are formed from oxidation of sulfur in fuel. The only means for controlling SO_2 and H_2SO_4 emissions from the Facility is to limit the sulfur content of the fuel. Natural gas has very low sulfur content, resulting in the lowest SO_2 and H_2SO_4 emission rates achievable for a combustion turbine. Because ULSD/Biodiesel contains

at most 15 parts per million of sulfur, SO_2 and H_2SO_4 emissions will be minimized to the maximum possible extent for any liquid fuel fired combustion turbine.

The Facility will utilize natural gas and ULSD/Biodiesel fuel, the fuels with the lowest sulfur content available for use by combustion turbines.

BACT for PM/PM_{10}/$PM_{2.5}$

Particulate matter (PM) from fuel combustion is primarily the result of non-combustible constituents (ash) in the fuel. For combustion turbines, all PM is typically less than 10 microns in diameter (PM_{10}). The emissions of fine particulate matter ($PM_{2.5}$) from the turbine have been conservatively assumed to be equal to the emissions of PM_{10}. It has also been assumed that the turbine's $PM_{2.5}$ emissions' filterable and condensible fractions are equal (each 50% of the total).

Particulate emission control is achieved at the source by efficiently burning low ash and low sulfur fuel. The Facility will use natural gas and ULSD/Biodiesel fuel only, combined with state-of-the-art combustion technology and operating controls, to provide the most stringent degree of particulate emissions control available for combustion turbines.

The use of natural gas as the primary fuel, and limited use of ULSD/Biodiesel as the back-up fuel will serve as BACT for PM/PM_{10}/$PM_{2.5}$. Particulate emissions will also be controlled through proper combustion in the combustion turbine. The proposed emission rates of 0.0040 lb/MMBtu heat input firing natural gas and 0.014 lb/MMBtu while firing ULSD/Biodiesel are consistent with recent BACT determinations, with consideration of the inclusion of the condensible fraction.

BACT for CO / VOC

CO and VOC emissions are formed due to incomplete combustion of the fuel. These emissions are typically higher during transient and low load operating conditions. Control technologies used to minimize CO/VOC emissions include the use of clean burning fuels, state-of-the-art combustion technology, add-on oxidation catalyst systems, and establishing minimum load restrictions.

The combustion turbine proposed for the Facility will use a combustor design and configuration that achieves a very low CO/VOC emission rate while burning natural gas and ULSD/Biodiesel fuel. Additional reduction of CO/VOC emissions will come from an oxidation catalyst located in the HRSG that is expected to achieve > 90% control efficiency. Except during periods of startup and shutdown, the combustion turbine will operate at greater than 60% load and will achieve combustion temperatures high enough to minimize CO/VOC formation in the combustion process.

For VOC control, the achievable VOC stack concentration is primarily dependent on the manufacturer and model of turbine. Similar projects are identified as utilizing an oxidation catalyst that results in a VOC stack concentration of 1.0 ppmvd @ 15% O_2 while firing natural gas and 2.5 to 7 ppmvd @ 15% O_2 while firing distillate oil.

The lowest permitted VOC stack concentration while firing oil identified for a project utilizing a Mitsubishi 501G turbine was 7 ppm, for the Fore River project in 2003, which was determined to be LAER and for the Millennium project in 2000 which was determined to be BACT. The Mirant Kendall project was permitted at 2.5 ppm VOC firing oil in 2003; however that project utilized a GE 7FA turbine

The proposed PVEC VOC BACT limit of 6 ppm while firing oil is the lowest stack concentration guaranteed by Mitsubishi for this turbine model, and is consistent with the range of recent permit limits and BACT/LAER determinations for projects utilizing the same or an equivalent turbine model.

The Facility proposes BACT for VOC as a stack concentration of 1.0 ppmvd @ 15% O_2 while firing natural gas and 6.0 ppmvd @ 15% O_2 while firing ULSD oil.

For CO control, similar projects are identified as using an oxidation catalyst that results in a CO stack concentration of 2 ppm @ 15% O_2 while firing natural gas and 6 ppm @ 15% O_2 while firing ULSD oil. The Facility proposes BACT for CO as a stack concentration of 2.0 ppm @ 15% O_2 while firing natural gas and 6.0 ppm @ 15% O_2 while firing ULSD/Biodiesel.

BACT for NH_3

The SCR emissions control systems will reduce the NO_X emissions from the turbine by injecting NH_3 into the exhaust gas stream upstream of a catalyst. Some portion of the injected NH_3 will pass through the catalyst unreacted, and is referred to as NH_3 slip. The SCR for the Facility will use a design that achieves an NH_3 slip among the lowest for similar units.

According to the RBLC database, the lowest NH_3 stack concentrations for a similar project are 2 ppm on natural gas and 5 ppm on oil. In Massachusetts, the most recently permitted projects have an NH_3 stack concentration limit of 2 ppm while firing natural gas and 2 ppm while firing fuel oil.

The Facility proposes as BACT an NH_3 stack concentration of 2.0 ppmvd at 15% O_2 while firing natural gas and 2.0 ppmvd at 15% O_2 while firing ULSD/Biodiesel.

BACT for CO_2

There are no add-on controls available for CO_2 emissions for the Facility. The Facility has been designed to provide a high level of CO_2 mitigation for an energy generating facility, primarily by the use of clean-burning fuels and highly efficient combustion and power generating technology. Another way the Facility design has been optimized for CO_2 mitigation is the use of a wet cooling tower.

PVEC will utilize clean burning natural gas as the primary fuel with ULSD as back-up for up to the equivalent of 1,440 hours (at maximum firing rate) annually. The gas turbine proposed by PVEC (Mitsubishi M501G) is one the most efficient turbines in its class with a gross heat rate of 5,846 Btu/kWH at 100% load. Comparable gas turbines range in efficiency from 5,950 to 6,100 Btu/kWH. A comparison of PVEC's average annual

CO_2 emission rate while firing natural gas to the latest ISO-New England Marginal Emission Rate and to other turbine models proposed for a similar combined cycle plant, is presented in Table 4 below. The data shows that the turbine proposed by PVEC has the lowest lb/MWh CO_2 emission rate of comparable turbines and is markedly below the New England Marginal Emission Rate.

Table 4
CO_2 Emission Rates

	New England Marginal Emission Rate (ISO-NE 2007)	MHI 501G (PVEC)	Comparable Gas Turbine #1	Comparable Gas Turbine #2	Comparable Gas Turbine #3
CO_2 Emissions (lb/MWh)	1004	759	777	769	773

Another factor in the reduction of CO_2 emissions is the use of wet cooling over other cooling methods to increase the efficiency of the PVEC. The use of a mechanical draft wet cooling tower is a more effective means of reducing the steam pressure in the condenser than an air cooled condenser. This increase in efficiency results in a reduction of nearly 51 MMBtu/hr of additional heat input or an additional 51,000 ft^3/hr of natural gas from a water-cooled facility compared to air cooled to produce the same amount of power.

This reduction in fuel use represents approximately 2% of the total fuel use required for the turbine at full load. Because the emissions of pollutants are proportional to the fuel use and heat input rates, the use of a mechanical draft wet cooling tower will result in proportionally less CO_2 emissions from the steam turbine generator, for the same power output. This gain in efficiency and reduction in fuel usage and emissions is expected over the full operating range of the turbine, and under all meteorological conditions as it is driven largely by the parasitic loads of the larger fans and pumps associated with dry cooling technology. Reductions in regional air emissions (including CO_2) will be facilitated by PVEC's use of wet cooling technology.

The use of the efficient MHI 501G combustion turbine and wet cooling technology by PVEC will result in the highest level of CO_2 emissions control available for a project of this type. A more detailed discussion of **BACT for CO_2** can be found in a submittal made by PVEC to MassDEP dated December 16, 2010 and entitled "Best Available Control Technology Analysis for Greenhouse Gas Emissions".

BACT for Hazardous Air Pollutants (HAPS)

Combustion turbines generally have lower HAP emissions than other combustion sources due to the high combustion temperatures reached during normal operation. The primary HAPs emitted from natural gas and distillate oil fired combustion turbines are formaldehyde, polycyclic aromatic hydrocarbons (PAH), benzene, toluene, and xylenes, while small amounts of metallic HAP carried over from the fuel constituents are also present in the emissions from distillate-oil fired turbines.

Like CO and VOC, most HAP emissions are generated due to incomplete combustion of fuel. The control technologies for minimizing HAP emissions achieved in practice are combustion control and the use of an oxidation catalyst, which represents the BACT determination for HAPs for the Facility.

BACT for Auxiliary Boiler

The auxiliary boiler will fire natural gas only. Operation of the unit will be limited to the fuel use equivalent (at maximum firing rate) of 1,100 hours of operation in any 12 consecutive month period.

Emissions will be controlled through the use of clean burning natural gas, state-of-the-art combustion controls, and limitations on annual operation. The auxiliary boiler will meet the natural gas emission limits listed in 310 CMR 7.26(33)(b) which were limitations developed to meet BACT requirements. The visible emissions from the auxiliary boiler will not exceed 10% opacity at any time during boiler operation.

BACT for Emergency Engines

Emissions will be controlled through the use of clean burning ULSD/Biodiesel fuel with a sulfur content of 15 parts per million or less, state-of-the-art combustion controls, and limitations on annual operation. Annual operations of the emergency generator and the fire pump will be limited to 300 hours each. The units will typically operate no more than one hour per week for maintenance and reliability testing.

The proposed units will comply with the applicable EPA non-road engine standard emissions limits at the time of installation.

VI. Facility Noise

An operational noise assessment was performed for the proposed Pioneer Valley Energy Center. The noise assessment was conducted in accordance with 310 CMR 7.10 and MassDEP Noise Policy 90-001, which states that new equipment is not permitted to increase ambient sound levels by more than 10 decibels above the lowest measured background sound level at both the property boundaries and the nearest inhabited structures. In addition, new equipment is not permitted to emit a pure-tone noise which occurs when any octave band center frequency sound pressure level exceeds the two adjacent center frequency sound pressure levels by 3 decibels or more.

Ambient noise levels

Existing ambient noise levels were measured continuously for a week from March 6th, 2008 through March 13th, 2008 at five property line positions surrounding the proposed Facility, and at the four nearest residential receptors in various directions from the plant. The noise measurement locations chosen are listed in Table 5 as follows:

Table 5
Noise Level Measurement Locations

Location	Address	Latitude	Longitude	Distance from Stack
PL-1	Edge of Ampad Road across from Ampad facility	+42° 09' 40.74"	-72° 44' 31.40"	324 ft
PL-2	Ampad Road & Servistar Industrial Way, behind American Canvas Company	+42° 09' 32.49"	-72° 44' 27.34"	1030 ft
PL-3	Wooded area along power line right-of-way	+42° 09' 42.08"	-72° 44' 22.91"	367 ft
PL-4	Near Servistar Industrial Way & Egleston Rd, behind Custom Wood Products Co.	+42° 09' 41.41"	-72° 44' 10.39"	1305 ft
PL-5	Edge of Servistar Industrial Way across from Lowe's Distribution Warehouse	+42° 09' 33.83"	-72° 44' 13.57"	1371 ft
RES-6	1 Williams Way	+42° 09' 47.02"	-72° 45' 02.35"	2670 ft
RES-7	47 Barbara Street	+42° 09' 12.70"	-72° 44' 04.77"	3464 ft
RES-8	21 West Glen Road	+42° 09' 29.96"	-72° 43' 51.01"	3037 ft
RES-9	323 Lockhouse Street	+42° 09' 21.51"	-72° 44' 44.88"	2496 ft

PL = Property Line; RES = Residential

Short-term and long-term noise measurements were performed in order to document broadband and octave band ambient noise levels, and to evaluate trends in noise levels over several days in order to find the quietest time periods.

The weather conditions during the measurement sessions were as follows: clear skies, 30 to 40 degrees F, mild winds, and no precipitation. Audible noise sources observed during the measurement sessions included local traffic, distant traffic, aircraft overflights (propeller, jet and helicopter), distant trucking activities, distant train horns, babbling brooks, distant hand tools, birds, wind in the trees, and distant backup alarms.

A CEL Instruments Model 593 Noise Analyzer was used for the short-term noise measurements. The CEL 593 was programmed to measure and record Leq and L_{90} noise data using an RMS "slow" time response.

Several LD Model 720 Environmental Noise Monitors were used for the long-term noise measurements to evaluate trends in noise levels over several days. The LD 720s were programmed to measure statistical noise data in hourly intervals using an RMS "slow" time response. Measured noise metrics included the Leq, L_{10} and L_{90} noise levels in A-weighted decibels (dBA).

A B&K Model 4231 Acoustical Calibrator was used in the field both before and after all measurement sessions in order to ensure that the CEL 593 and LD 720s were calibrated and functioning properly. The B&K 4231 produces a reference accuracy 1 KHz pure tone at 94 dB and 114 dB levels. All the instrumentation used in this study operated as expected and remained calibrated throughout their use.

Noise Producing Equipment

The significant noise producing equipment is accounted for in PVEC's noise prediction model. Interior and exterior noise-producing equipment, and the number of each, consist of the following as depicted in Table 6:

Table 6
Identification of Noise-Producing Equipment

Exterior Equipment		Interior Equipment	
1 Exhaust Stack	1 STG Transformer	1 Gas Turbine	1 Steam Turbine Generator
1 Gas Turbine Inlet Air Filter	1 Auxiliary Transformer	1 Heat Recovery Steam Generator	2 Feed Pumps
1 Wet Cooling Tower	12 HVAC Supply Fans	1 Gas Turbine Generator	2 closed Cooling Water Pumps
1 TCA/FGH Heat Exchanger	12 HVAC Roof Exhaust Fans	1 Gas Turbine Slip Ring House	2 Air Compressors
1 CTG Transformer		1 Steam Turbine	2 Gas Compressors

There will also be an emergency power diesel generator, equipped with a critical grade silencer, located inside the powerhouse building and enclosed in its own generator room. The generator will run only during emergency loss-of-power conditions and will be function tested only during daytime periods. As such the emergency generator was not included in the noise predictions because its noise will be fully controlled and it will run on occasion for only very brief periods of time (up to one hour per week).

Operational Noise Predictions

Future noise levels for PVEC were predicted using the Cadna-A® noise model, a sophisticated three dimensional model for sound propagation and attenuation based on International Standard ISO 9613-25. In the model, a noise source is assembled from point, line and/or area components. Distance losses, ground attenuation, and barrier/berm effects are applied automatically, and the resulting noise levels are computed at any number of receptor locations of interest.

Noise sources can be modeled as exterior or interior sound power levels. For interior equipment, the structure's transmission loss values for the various octave bands are entered into the Cadna-A model to account for noise losses through enclosure buildings such as the powerhouse. The powerhouse itself is also modeled as a structure so that it acts as a barrier to noise propagating in certain directions from exterior equipment located close to it. Finally the model can generate noise contour lines on a base map showing how noise radiates from the sources and is affected by intervening structures and terrain.

The Cadna-A model was first configured by importing a Google Earth® base map of the area. In this manner the positions of various buildings, receptor locations and distances can be assured to a high degree of accuracy. The sound power octave band spectra of the exterior and interior equipment were then assembled from manufacturer's data and entered into the model. Where manufacturer noise data were not available, sound power emission data were estimated from accepted acoustical industry methods based on the equipment's operating capacities (such as horsepower, etc.). Finally, receptor locations were selected, and their existing ambient noise levels were specified, to allow the model to evaluate the resulting noise levels for compliance with applicable MassDEP noise criteria limits.

In the Cadna-A model results assume that the listed proactive noise control measures have been implemented. These include (1) increasing the powerhouse walls to an STC rating of 56 or greater, (2) installing a bullet-type silencer in the exhaust stack, (3) relocating the cooling tower to a more centralized location on the site, and (4) installing a rooftop parapet on the powerhouse.

Noise Control Technology Analysis

Five control technologies were evaluated in the design of the Facility to explore the potential noise reduction benefits and potential costs of various control technologies added to the "base case" noise control measures. The potential costs associated with each option were estimated using standard construction estimating practices and vendor information.

The noise BACT analysis considered the following options:

Option 1: The ***Cooling Tower*** noise control option will reduce noise by constructing the cooling tower with a single air entry side facing the plant with low noise fans, motors, and gear boxes, and by constructing a 15-feet tall barrier walls on top of the cooling tower to shield the fans.

Option 2: The ***Localized Enclosure*** noise control option involves installation of acoustic enclosures around the major equipment in the powerhouse. The equipment identified as the major contributors to internal noise are boiler feed pumps, raw water circulation pumps, and air compressors.

Option 3: The ***Modify HRSG*** noise control option includes increasing the casing thickness of the HRSG and installing additional lagging to the outer surface of the HRSG.

Option 4: The ***Noise Barrier along South*** noise control option entails installation of a sound barrier wall 300 feet in length by 23 feet in height in proximity to the transformers to provide noise reduction for the receptors to the south of the transformers.

Option 5: The ***Enhanced Power House Wall*** noise control option entails constructing the powerhouse walls out of a more dense material to reduce the amount of noise transferred through the walls.

Option 1 will be implemented into the design of the Facility. Options 2 and 4 do not provide effective noise mitigation at multiple receptor locations. Options 3 and 5 can provide substantial noise reduction but only for one particular noise receptor at significantly increased project cost. Options 2, 3, 4 and 5 will not be implemented.

Table 7 presents a summary of the five BACT noise control options, as follows:

Table 7
Summary of BACT Noise Mitigation Benefits and Costs

Site No.	BASE Predicted Noise Level (Plant+Ambient) Leq, dBA	Resulting Change in Predicted Noise Levels				
		Option 1: Cooling Tower Options	Option 2: Localized Enclosures	Option 3: Modify HRSG	Option 4: Noise Barrier Along South	Option 5: Enhanced Power House Wall STC
PL-1	54	0	0	-8	0	-4
PL-2	54	-3	0	0	-1	0
PL-3	63	-5	0	0	0	0
PL-4	50	-3	0	0	0	0
PL-5	51	-4	0	0	0	0
RES-1	38	0	0	-1	0	-1
RES-2	40	-1	0	0	0	0
RES-3	44	-1	0	0	0	0
RES-4	41	-1	0	0	0	0
Option implementation costs ($)		$1,425,000	$1,240,000	$8,000,000	$345,000	$3,380,000
Selected for implementation?		Yes	No	No	No	No

Conclusions

Predicted operational noise levels are expected to comply with MassDEP noise criteria limits at all residential and property line receptor locations except at the property line receptors PL-1 and PL-3. PVEC has obtained releases from the adjacent property owners at PL-1 where the predicted noise levels exceed the MassDEP noise policy criteria. No release was sought at PL-3 since that location, coinciding with a power line right-of-way, is not buildable and not a potential sensitive receptor.

The cooling tower and breakout noise through the powerhouse walls are expected to be the significant contributors of noise at each property line location. The predicted plant operation will not produce any pure-tone condition. The noise prediction results are presented in Table B-1 in Appendix B of this document.

VII. Air Quality Modeling Analysis

The USEPA established the National Ambient Air Quality Standards (NAAQS) to protect human health and the environment, including the most sensitive of the population, with a margin of safety. The MassDEP has adopted the NAAQS and requires that proposed facilities demonstrate that their emissions will not cause or contribute to an exceedance of the NAAQS through an ambient air quality impact analysis using USEPA and MassDEP approved air dispersion modeling techniques.

Air Modeling Results

Criteria Pollutant Modeling Results

Tables B-2 and B-3 in Appendix B of this document summarize the results of the criteria pollutant modeling analysis. Table B-2 shows that the maximum modeled Facility impact concentrations are below the applicable Significant Impact Levels ("SILs"), and, when combined with background concentrations from representative area monitoring stations, the cumulative predicted air quality concentrations are also below the applicable NAAQS.

Table B-3 presents a comparison of the maximum modeled Facility impact concentrations in comparison with their respective PSD increments. Where refined modeling based on individual source maxima was sufficient to demonstrate modeled concentrations that are less than the SILs, those results are also included. Table B-3 shows that the maximum modeled Facility impact concentrations are each below their respective PSD increments.

1-Hour NO_2 Results

EPA finalized the 1-hour NO_2 NAAQS on January 22, 2010. The standard is 100 ppb (188.7 ug/m^3), based on the three year average of the 98th percentile of the daily maximum one hour average.

PVEC's 1-hour background concentration is 42 ppb (79.2 ug/m^3). This value was provided by MassDEP and was calculated as the 3-year average of the 98th percentile values during the years 2007-2009 at Anderson Road at Westover Air Force Base in Chicopee. The maximum predicted 1-hour NO_2 impacts during normal operation when combined with the background concentration, result in a maximum total modeled concentration of 86 ppb (165 ug/m^3), which is less than the NAAQS for 1-hour NO_2.

Air Toxics Modeling Results

The dispersion modeling analysis results were also used to determine the Facility's maximum potential impacts of air toxics in the ambient air. The potential 24-hour and annual ambient impacts for each air toxic compound listed in MassDEP guidance was determined for each of PVEC's sources by comparing those predicted emission rates to the criteria pollutant emission rates and resulting impacts determined from the AERMOD refined modeling. The combined ambient air toxics impacts were calculated using the same conservative methodology as was used for the refined modeling analysis (i.e. simple summing of the maximum impact of each source without consideration for whether those impacts occurred at the same location). The results of the analysis demonstrate that the worst case ambient impacts of each listed air toxics compound fall below their respective

24-hour average Threshold Effects Exposure Limit (TEL) and annual average Allowable Ambient Limit (AAL) established in MassDEP's guidelines.

Air Modeling Discussion

Source Emissions and Stack Data
The stack dimensions of the fossil fuel burning equipment along with the exhaust parameters used in the modeling analysis are presented in Tables B-4, B-5, B-6, and B-7 in Appendix B of this document.

Dispersion Environment
The type of land surface covering (buildings and roads versus vegetation and water, for instance) affects the way emissions mix in the air. Land use within a three-kilometer radius of the Facility was classified in accordance with the MassDEP recommended method, which involves review of information provided by USGS topographic maps. This analysis determined that the area within three kilometers of the Facility is predominantly rural.

Good Engineering Practice (GEP) Stack Height Determination
USEPA regulations establish limitations on the stack height that may be used in dispersion modeling to calculate air quality impacts of a source. Each source must be modeled at its actual physical height unless that height exceeds its calculated Good Engineering Practice (GEP) stack height. A GEP stack height analysis was performed for the Facility, in accordance with EPA guidance. The results of the analysis indicated that none of the proposed Facility stack heights exceeds their associated GEP stack height; therefore, their proposed heights were used in the modeling and an assessment of building downwash was conducted.

Cavity Region
Buildings located near stacks can create cavity regions which can trap the source's emissions and result in locally high concentrations of air contaminants. The Facility's 180 foot tall turbine stack is above the calculated cavity height of the adjacent structures (equal to 1.5 times the building height or 172.5 feet), so an assessment of cavity impacts was not required. However an analysis of potential cavity impacts was conducted in the modeling analysis in order to assure a complete assessment.

Local Topography
Local topography plays a role in the selection of an appropriate dispersion model. Dispersion models can be divided into two categories: (1) those applicable to areas where terrain is less than the height of the top of the stack (simple terrain), and (2) those applicable to areas where terrain is greater than the height of the top of the stack (complex terrain). Terrain in the immediate area of the Facility is relatively flat. The closest complex terrain for the turbine stack is found approximately 3,000 meters from the turbine stack. Models were selected that are suitable to evaluate both simple and complex terrain impacts.

Preliminary Screening Modeling
Initial modeling was conducted using the EPA approved SCREEN3 dispersion model. The SCREEN3 model provides highly conservative/worst case impact predictions as it determines worst case meteorological conditions from a default data set and assumes that those conditions persist 100% of the time.

Impacts in simple terrain, complex terrain, and cavity regions were all evaluated. Simple terrain modeling was conducted for receptors located up to 3 kilometers (km) from the turbine stack. Complex terrain modeling was conducted for receptors located from 3 to 20 km from the turbine stack. Impacts were evaluated with the portion of the cavity region created by the Facility's structures that extend off the site boundaries. An additional receptor was placed at the closest distance beyond the potential cavity region to assure that potential ambient impacts close to the sources themselves were fully evaluated.

The SCREEN3 model predicted the maximum one-hour average ambient air impact concentration for each pollutant resulting from the independent operation of PVEC's emissions sources (i.e. the combustion turbine firing natural gas, the combustion turbine firing ULSD/Biodiesel, the auxiliary boiler, the emergency generator, and the fire pump). Impacts corresponding to each of the averaging periods established in the NAAQS (i.e. three-hour, eight-hour, 24-hour and annual) were determined by applying EPA recommended scaling factors to the maximum hourly average-impacts predicted by the SCREEN model. The maximum predicted short term impacts from the emergency generator and fire pump were pro-rated for the fact that their concurrent operation with the combustion turbine operation will be limited to one hour per week for maintenance testing.

The total worst case potential impacts of the Facility were then determined by adding the individual impact concentrations of each of the sources, without consideration for whether those impacts occurred at the same location under the same meteorological conditions.

This conservative analyses predicted that only the annual NO_2, 3-hour, 24-hour and annual SO_2, and 24-hour and annual PM_{10} and $PM_{2.5}$ impacts could possibly exceed EPA's Significant Impact Levels (SILs). Refined modeling was therefore conducted for these pollutants and averaging times for a more accurate determination of impacts.

Preliminary Refined Modeling
A preliminary refined modeling analysis was conducted using the EPA approved AERMOD model. AERMOD uses five years of actual hourly meteorological data from the project area to more accurately predict dispersion and potential impacts than the worst case conditions used by the SCREEN3 model. A receptor grid was established at intervals ranging from 50 to 500 meters out to 10 km from the turbine stack.

The preliminary refined modeling analyses were conducted using the same source operating conditions and limitations on source operating hours as were used for the SCREEN3 modeling analyses. Similar to the SCREEN3 model analysis, the AERMOD model was used to predict the impacts from each individual source for each pollutant and averaging period. The total Facility impact concentrations were then determined using the same methodology as was used to estimate total Facility impact concentrations during the screening modeling analyses: summation of the highest predicted impacts of each individual source.

The preliminary refined modeling analyses predicted that the maximum impacts for all pollutants and averaging periods would fall below EPA's SILS with the exception of 24-hour $PM_{2.5}$ impacts. These estimates of the total Facility impact concentrations were again conservative in that they assumed that the maximum impacts from all Facility sources occur at the same receptor location, and at the same time. Given these results, further refined modeling was conducted to determine whether the 24-hour $PM_{2.5}$ impacts would fall below the SILs when a more detailed analysis was used.

Pollutant-Specific Refined Modeling
The AERMOD model provides both the location and the date (from the 5-year meteorological data set) that the maximum impact was predicted to occur. The total Facility impacts determined during the prior modeling analysis were based on the conservative assumption that the maximum impact predicted from each of the sources occurs at the same receptor location at the same time. However, closer review of the model results indicated that the maximum impacts predicted for the combustion turbine and auxiliary boiler were actually predicted to occur at different dates and locations than the maximum impacts predicted for the emergency generator and fire pump. When the actual concentrations of the predicted impacts at each individual receptor location were considered, the combined 24-hour $PM_{2.5}$ impact concentrations from the Facility's sources were found to all fall below the EPA's SILs.

The above analyses determined that the impacts of the Facility's sources would be below all applicable Significant Impact Levels and thus, EPA regulations establish that interactive modeling of other sources operating in the project area is not required.

Background Air Quality
Although interactive modeling was not required, the cumulative impacts of PVEC with those resulting from existing sources was determined by considering background air quality. As there are no ambient monitoring stations located in Westfield, background monitoring data from the nearest monitoring stations, located in Chicopee and Springfield, were used to represent the existing background air quality in the area of the Site. When the maximum predicted impacts of PVEC's sources were combined with background concentrations from those monitoring stations, the cumulative predicted air quality concentrations were determined to be below the applicable NAAQS.

VIII. Provisions of Approval

Additional Approvals Needed

1. PVEC shall submit to the MassDEP, in accordance with the provisions of Regulation 310 CMR 7.02(5)(a), a non-major comprehensive plan application for written MassDEP approval, once the system specific information has been determined, but in any case not later than 180 days prior to the CTG start-up, for the combustion turbine, CEMS, SCR control system, NH_3 handling & storage system, and CO catalyst control systems.

   PVEC shall not commence installation of any of these system components prior to receiving written MassDEP approval.

2. PVEC shall submit to the MassDEP before startup, in accordance with the provisions of Regulation 310 CMR 7.02(4), a Limited Plan Application for written MassDEP approval detailing a quality control/quality assurance (QA/QC) program for the long term operation of the CEMS and COMS and the temperature monitoring systems. The CEMS/COMS program must conform to 40 CFR Part 60, Appendix F, all applicable portions of 40 CFR Parts 72 and 75, and 310 CMR 7.28 (NOx Allowance Trading Program).

3. ***Prior to the commencement of any construction at the PVEC site***, PVEC shall ensure:
   a. that a 14-day (minimum) ambient air monitoring program is conducted on or near the proposed PVEC project site, as represented in the proposed scope of work submitted by ESS Group, Inc. to PVEC and approved by MassDEP on June 29, 2009, and
   b. that the results of the monitoring program are analyzed and a comprehensive report detailing the monitoring program results is written and submitted to MassDEP for review, and
   c. that the results of the monitoring program are acceptable to MassDEP, and
   d. that the monitoring program results and report is approved in writing by the MassDEP.

   The purpose of the monitoring program is to obtain a short-term portrayal of the actual background ambient air concentration of particulate matter less than 2.5 microns in diameter (“$PM_{2.5}$”) in the area of the proposed PVEC facility.

Other Terms and Conditions

4. In accordance with Regulation 310 CMR 7.02(3)(k), MassDEP may revoke this plan approval if construction has not commenced within two years of the date of this plan approval, or if during construction, construction is suspended for a period of one year or more. Construction is considered to have commenced if the owner or operator of the facility has begun a continuous program of physical on-site construction of the facility that is permanent in nature.

5. In accordance with Regulation 310 CMR 7.00: Appendix A(10)(c), approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. MassDEP may extend the 18-month period upon a satisfactory showing that an extension is justified.

6 This Approval may be suspended, modified, or revoked by the MassDEP if, at any time, the MassDEP determines that PVEC is violating any condition or part of the approval.

7. This Approval does not negate the responsibility of PVEC to comply with this or any other applicable federal, state, or local regulations now or in the future. This Approval does not imply compliance with any other applicable federal, state or local regulation now or in the future.

8. Compliance with the emission limits contained herein shall be determined by data collected by CEMS as specified within this Approval and/or by stack emission test methods as approved by the MassDEP. The MassDEP may also use any credible evidence in its determination of compliance with the limits and conditions specified in these approvals.

Emission Limits & Restrictions

9. PVEC shall keep emission rates at the lowest practical level at all times, but shall not exceed the emission limits specified in Tables 8, 9, 10, and 11 as follows:

Table 8
CTG Emission Limits/Restrictions

Emission Unit	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards (1)(2)(3)						Restrictions	Restrictions
			natural gas			ULSD/Biodiesel			tons per year emitted (5)	Hours of operation while burning ULSD/Biodiesel
			lb/MMBtu	ppmvd (4)	lb/hr	lb/MMBtu	ppmvd (4)	lb/hr		
CTG	natural gas or ULSD / Biodiesel	PM_{10} / $PM_{2.5}$ (6) (total)	0.0040	–	9.8	0.014	–	26.8	51.0	≤ 16,128,366 gallons oil firing (46 days equivalent) from January 1st to November 30th, with no oil firing May 1st to September 30th, and ≤ 4,908,633 gallons oil firing (14 days equivalent) from December 1st to December 31st (8) (based on a fuel heating value of 138,000 Btu/gallon)
		PM_{10} / $PM_{2.5}$ (7) (filterable)	0.0020	–	4.9	0.007	–	13.4	25.5	
		PM_{10} / $PM_{2.5}$ (7) (condensible)	0.0020	–	4.9	0.007	–	13.4	25.5	
		Sulfur Dioxide	0.0019	–	4.7	0.0017	–	3.4	18.0	
		Nitrogen Oxides	0.0080	2.0	20.2	0.021	5.0	43.0	110.9	
		Carbon Monoxide	0.0049	2.0	12.3	0.016	6.0	31.5	549.9	
		VOC	0.0015	1.0	3.6	0.0090	6.0	18.0	24.8	
		Sulfuric Acid Mist	0.0019	–	4.9	0.0018	–	3.6	18.0	
		Formaldehyde	0.00028	–	0.6	0.00031	–	0.6	2.6	
		Ammonia	0.003	2.0	7.5	0.0032	2.0	6.4	28.8	
		Sulfur in Fuel	≤ 0.6 gr sulfur / 100 ft^3			15 ppm sulfur by weight				
		Opacity/Smoke	≤10% during normal operation, based on a 6-minute block average							

(1) The emission rates for the CTG are based on worst case emission rate (100% load and 0°F ambient temp.),
(2) The lb/MMBtu, ppmvd, and lb/hr emission rates are based on a 1-hour block average.
(3) The emission limits in Table 8 apply from the minimum sustained operating load to 100% load, and do not apply during start-up, shutdown, fuel transfers, and equipment cleaning.
(4) "ppmvd" emission limits are corrected to 15% O_2.
(5) Including startups and shutdowns, assuming 141 warm starts (2.0 hrs each), 35 cold starts (5.0 hrs each), and 176 shutdowns (1.0 hrs each). Actual number of warm and cold starts and shutdowns may vary provided that annual emission limits are not exceeded. See Special Provision 5 in Table 15-a "Special Terms & Conditions".
(6) Particulate matter as measured by 40 CFR Part 60, Method 5
(7) Particulate matter as measured by 40 CFR 51, Appendix M, Test Method 201 or 201A and Test Method 202, or as otherwise approved by the MassDEP.

Table 9
Auxiliary Boiler Emission Limits/Restrictions

Emission Unit	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards (1)(2)(3) lb/hr	lb/MMBtu	Restrictions
Auxiliary Boiler	natural gas	$PM/PM_{10}/PM_{2.5}$ (4)	0.10	0.0048	1,100 hours (full load equivalent) per rolling 12-month total
		Sulfur Dioxide	0.01	0.00050	
		Nitrogen Oxides	0.58	0.029	
		Carbon Monoxide	0.74	0.037	
		VOC	0.060	0.0030	
		Sulfuric Acid Mist	0.01	0.0005	
		Formaldehyde	0.0015	0.000075	
		Sulfur in Fuel	$\leq$ 0.6 gr sulfur / 100 ft^3		
		Opacity/Smoke	$\leq$ 10% during normal operation, based on a 6-minute block average		

(1) The emission rates for the Auxiliary Boiler are based on worst case emission rate.
(2) The lb/hr and lb/MMBtu emission rates are based on a 1-hour block average.
(3) The emission limits in Table 9 apply from the minimum sustained operating load to 100% load, and do not apply during start-up, shutdown, fuel transfers, and equipment cleaning.
(4) Particulate matter as measured by 40 CFR 51, Appendix M, Test Method 201 or 201A and Test Method 202, or as otherwise approved by the MassDEP.

Table 10
Emergency Generator Engine Emissions

Pollutant	Tier 2 Standard	Emissions	Emissions
NOx & NMHC	6.4 g/KWh	37.5 lb/hr	5.6 tpy
CO	3.5 g/KWh	12.2 lb/hr	1.8 tpy
VOC(1)	1.3 g/KWh	1.7 lb/hr	0.3 tpy
$PM/PM_{10}/PM_{2.5}$	0.20 g/KWh	0.91 lb/hr	1.4 tpy
SO_2	n/a	3.1 lb/hr	0.5 tpy
Formaldehyde	n/a	0.0015 lb/hr	0.0002 tpy

(1) Tier 2 standard for NOx and VOC is 6.4 g/KWh, combined. For worst case potential emissions, assumed NOx emissions equal to this level and VOC emissions equal to the older Tier 1 limit of 1.3 g/KWh.

Table 11
CTG Startup/Shutdown Emission Limits (1)(2)(3)(4)

Pollutant	Natural Gas Firing	ULSD Firing
PM/PM_{10}/$PM_{2.5}$	6.1 lb/hr	18.2 lb/hr
SO_2	2.9 lb/hr	2.4 lb/hr
NOx	62.0 lb/hr; 40 ppmvd @ 15% O_2	99.0 lb/hr; 60 ppmvd @ 15% O_2
CO	First 60 minutes: 2000 lb/hr and 1100 ppmvd @ 15% O_2 After 60 minutes: 400 lb/hr and 100 ppmvd @ 15% O_2	First 60 minutes: 6000 lb/hr and 4000 ppmvd @ 15% O_2 After 60 minutes: 800 lb/hr and 250 ppmvd @ 15% O_2
VOC	2.2 lb/hr	12.5 lb/hr
H_2SO_4	3.0 lb/hr	2.5 lb/hr
Formaldehyde	0.40 lb/hr	0.42 lb/hr
NH_3	8.0 lb/hr	8.0 lb/hr

(1) Startup is defined from the time that flame in the turbine combustor is initiated until minimum sustained operating load is achieved. The duration of warm/cold startups shall not exceed 2.0/5.0 hours respectively. Cold startups are defined as occurring after a period of greater than 24 hours of turbine shutdown, and warm startups are defined as occurring after 24 hours or less since turbine shutdown.

(2) Shutdown is defined as the time when the turbine operation is between minimum sustained operating load and flame-out in the turbine combustor occurs. The duration of shutdown shall not exceed 1.0 hours.

(3) Startup/shutdown emission limits are subject to revision based on results of compliance stack testing and CEMS data.

(4) All mass emission rate limits are based on a one hour average.

10. PVEC is subject to the monitoring, testing, record-keeping, and reporting requirements as contained in Tables 12-a thru 12-e, 13, and 14 and the applicable requirements as contained in Tables 8-11, unless otherwise specified below.

Table 12-a

Emission Unit	**Testing Requirements**
CTG	Stack Emissions Testing PVEC shall 1. Ensure that all stacks are constructed so as to accommodate the emissions testing requirements as stipulated in 40 CFR Part 60, Appendix A. The four outlet sampling ports (90 degrees apart from each other) for each stack must be located at a minimum of one duct diameter upstream and two duct diameters downstream of any flow disturbance. Ensure that all emissions testing is conducted in accordance with the MassDEP's "Guidelines for Source Emission Testing" and in accordance with the Environmental Protection Agency tests as specified in the 40 CFR Part 60, Appendix A, 40 CFR Part 60 Subpart KKKK, or by a methodology approved by the MassDEP. 2. Ensure that all CTG emissions tests are completed within 180 days after initial start-up of the CTG. 3. Submit emission test protocol(s) (including testing for startup and shutdown emissions) for review and written MassDEP approval at least 60 days prior to the date of actual testing. 4. Submit the final emission test report(s) / noise test report(s) to the MassDEP within 60 days after the completion of each of the tests. 5. Conduct initial compliance emission tests at maximum load, minimum sustained operating load, and at one other load point in between, to determine compliance with the emission limits (lb/hr, lb/MMBtu, ppmvd, and opacity) established in Table 8 & 9 for the following: Oil: NOx, CO, VOC, NH_3 $PM/PM_{10}/PM_{2.5}$, Sulfuric Acid Mist, Opacity Natural Gas: NOx , CO, VOC, NH_3, $PM/PM_{10}/PM_{2.5}$, Sulfuric Acid Mist 6 Ensure that for the determination of compliance with the PM_{10} emission limits, the owner/operator measures PM_{10} using 40 CFR 51, Appendix M, Test Method 201 or 201a, and Test Method 202, or using other test methods as approved by MassDEP. 7. Conduct initial compliance tests for the duration of start-up and shut down periods for the CTG. Emission data generated from this testing shall be made available for review by the MassDEP prior to confirming or modifying the maximum allowable emission rate limits (lb/hr, lb/MMBtu, ppmvd), including smoke and opacity limits, for these periods of time. The MassDEP shall incorporate these emission limits into the Final Approval for the CTG upon issuance and such limits shall be considered enforceable. This testing shall be for NOx, CO, VOC, and opacity. 8. Conduct a second emissions test for PM_{10} while burning ULSD/Biodiesel one year after the initial stack tests for the combustion turbine is completed. If the second stack tests show that the emissions unit is in compliance, additional stack testing shall be required only when requested by the MassDEP and/or EPA.

Table 12-b	
Emission Unit	**Testing Requirements**
Plant-Wide	Noise Testing PVEC shall 9. Ensure that all noise compliance tests are conducted within 180 days after initial start-up of the new Facility. 10. Ensure that noise testing is conducted in a manner that is substantially identical to the background noise testing and reflects worst case noise testing conditions. 11. Ensure that the MassDEP is notified of compliance noise testing no less than 3 days in advance of the testing. 12. Conduct noise testing to document Facility noise levels with the new CTG operating at full load, or at another load point agreed to by the MassDEP in writing. 13. Conduct noise testing to determine if PVEC can operate the Facility in compliance with the property-line noise limits specified in Table B-1 in Appendix B of this document. 14. If the property-line test results indicate a condition of non-compliance with Table B-1 in Appendix B of this document, work in full cooperation with the MassDEP to implement changes to the Facility to bring it into compliance with the property-line noise levels specified in Table B-1 in Appendix B of this document within 180 days of measuring the non-compliant noise situation. The MassDEP shall be notified in advance of any physical changes at the Facility to reduce noise, and of the times any noise measurements will be made to determine the effect of the changes made. 15. Ensure that the Facility is designed, constructed, operated and maintained such that at all times: a. No condition of air pollution will be caused by emissions of sound as provided in 310 CMR 7.01; b. No sound emissions resulting in noise will occur as provided in 310 CMR 7.10 and the MassDEP's Policy 90-001 other than approved herein; and c. Sound emissions from the Facility will not exceed the levels set forth in Table B-1 in Appendix B of this document at the property-line locations identified herein and in the Application. 16. Assent to MassDEP's right to require additional noise measurement periods, locations, or events if in the opinion of the MassDEP such additional measurements are necessary to determine compliance with the Air Pollution Control Regulations.

Table 12-c	
Emission Unit	**Monitoring Requirements**
CTG	**Opacity/Particulate Emission Monitor** PVEC shall 17. Install, calibrate, operate, and maintain a Data Acquisition and Handling System(s) (DAHS) and opacity or particulate emission monitor to continuously monitor and record opacity/particulate emissions from the subject emission unit stack(s). 18. Equip the opacity/particulate emission monitor with audible and visible alarms which activate when opacity/particulate emission exceeds the limits established herein. 19. Operate the opacity/particulate emission monitor at all times the subject emission unit is operating, except for periods of calibration checks, zero and span adjustments, and preventive maintenance. 20. Obtain and record emission data from each opacity/particulate emission monitor for at least 75% of the hours per calendar day for 75% of the days per calendar month, and 95% of the hours per calendar quarter that the subject emission unit operates, except for periods of calibration checks, zero and span adjustments, and preventive maintenance. 21. Maintain on-site for the opacity/particulate emission monitor an adequate supply of spare parts to maintain the on-line availability and data capture requirements contained herein. 22. Use and maintain the opacity/particulate emission monitor as a “direct-compliance” monitor to measure compliance with the opacity/particulate emission limit contained herein. A “Direct-compliance” monitor generates data that legally documents the compliance status of a source. The MassDEP may also use the opacity/particulate emission monitor or any credible evidence in its determination of compliance with the limits and conditions specified in this approval. 23. Ensure that the opacity/particulate emission monitor equipment complies with MassDEP approved performance and location specifications, and conforms with the EPA monitoring specifications in 40 CFR Part 60. **Temperature Monitoring System** PVEC shall 24. Install, calibrate, operate, and maintain a temperature monitoring system to continuously monitor and record the inlet temperatures to the SCR and the CO catalysts for the CTG/HRSG. 25. Equip each temperature monitoring system with audible and visible alarms which activate when these temperatures deviate from normal operating temperatures. 26. Operate all temperature monitoring equipment at all times the CTG is operating, except for periods of calibration checks, zero and span adjustments, and preventive maintenance. 27. Obtain and record temperature data from each temperature monitor specified herein for at least 75% of the hours per calendar day for at least 75% of the days per calendar month, and 95% of the hours per calendar quarter that the CTG operates, except for periods of calibration checks, zero and span adjustments, and preventive maintenance. 28. Maintain on-site for the temperature monitoring equipment an adequate supply of spare parts to maintain the on-line availability and data capture requirements contained herein. 29. Ensure that all temperature monitors and recording equipment comply with MassDEP approved performance and location specifications.

<table>
<tr><th colspan="2">Table 12-d</th></tr>
<tr><th>Emission Unit</th><th>Monitoring Requirements</th></tr>
<tr><td>CTG</td><td>PVEC shall
30. In accordance with 40 CFR Part 60; Subpart KKKK, in order to ensure that the natural gas burned in the new CTG qualifies for the Subpart KKKK natural gas sulfur monitoring exemption, which is based on historic gas sulfur content data being well below 0.06 lb/MMBtu SO_2 equivalent, ensure that periodic sampling is conducted consistent with 40 CFR Part 75 Appendix D, Section 2.3.1.4 (pipeline natural gas demonstration). This periodic test is an annual natural gas sulfur test to verify use of the Part 75 default SO_2 emission factor.

31. Install CEMS designed to meet the requirements under 40 CFR 75 for NOx and CO_2.

32. Comply with the alternative monitoring requirements contained in 40 CFR 75, Appendix D for SO_2 emissions and flue gas monitoring.</td></tr>
<tr><td>Emergency Engine & Fire Pump</td><td>PVEC shall
33. Monitor the hours of operation for each engine to ensure its operation does not exceed 300 hours per rolling 12-month period.

34. Monitor the circumstances of engine operation to ensure it operates only during
a. The normal maintenance and testing procedure as recommended by the manufacturer and/or National Fire Protection Association requirements, and
b. Periods of electric power outage due to failure of the grid, in whole or in part, on-site disaster, local equipment failure, flood, fire or natural disaster.</td></tr>
<tr><td>Emergency Engine</td><td>PVEC shall
35. Monitor the circumstances of engine operation to ensure it operates only when the imminent threat of a power outage is likely due to failure of the electrical supply or when capacity deficiencies result in a deviation of voltage from the electrical supplier to the premises of 3% above or 5% below standard voltage, or periods during which the regional transmission organization directs the implementation of voltage reductions, voluntary load curtailments by customers, or automatic or manual load shedding within Massachusetts in response to unusually low frequency, equipment overload, capacity or energy deficiency, unacceptable voltage levels, or other emergency conditions.</td></tr>
<tr><td>Plant-Wide</td><td>PVEC shall
36. Monitor sulfur content of each new shipment of ULSD/Biodiesel received. Compliance with % sulfur-in-fuel requirement can be demonstrated through testing (testing certification) or by maintaining a shipping receipt from the fuel supplier (shipping receipt certification).

The testing certification or shipping receipt certification of % sulfur-in-fuel shall document that sulfur testing has been done in accordance with the applicable ASTM test methods (D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01), or any other method approved by the MassDEP and EPA.

37. Ensure that the testing certification or shipping receipt certification includes a statement that the sampling was performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM D4057-88k, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products” and that no additions have been made to the supplier’s tank since sampling.

38. As an alternative to fuel supplier certification, PVEC may elect to take a manual sample after each addition of oil to the storage tank. Do not blend additional fuel with the sampled fuel prior to combustion. Sample according the single tank composite sampling procedure or all-levels sampling procedure in ASTM D4057-88, “Standard Practice for Manual Sampling of Petroleum and Petroleum Products.”</td></tr>
</table>

<table>
<tr><th colspan="2">Table 12-e</th></tr>
<tr><th>Emission Unit</th><th>Monitoring Requirements</th></tr>
<tr><td>CTG</td><td>PVEC shall
39. Install, calibrate, operate, and maintain a data acquisition and handling system(s) (DAHS) and stack CEMs to continuously monitor and record flue gas emissions of NOx, CO, NH_3, and diluent gas from the subject emission unit stack in accordance with the requirements stipulated in Tables 12-c and 12-d above and as noted below.

40. Equip each CEMs with audible and visible alarms which activate when emissions exceed the limits established herein.

41. Operate all CEMs at all times the subject emission unit is operating, except for periods of CEMs calibration checks, zero and span adjustments, and preventive maintenance.

42. Obtain and record emission data from each CEMs for at least 75% of the hours per calendar day for 75% of the days per calendar month, and 95% of the hours per calendar quarter that the subject emission unit operates, except for periods of calibration checks, zero and span adjustments, and preventive maintenance.

43. Maintain on-site for the CEMs equipment an adequate supply of spare parts to maintain the on-line availability and data capture requirements contained herein.

44. Use and maintain all its CEMs systems as “direct-compliance” monitors to measure compliance with the emission limits contained herein. “Direct-compliance” monitors generate data that legally documents the compliance status of a source. The MassDEP may also use the CEMs or any credible evidence in its determination of compliance with the limits and conditions specified in this approval.

45. Ensure that the CEMS equipment complies with MassDEP approved performance and location specifications, and conforms with the EPA monitoring specifications specified in 40 CFR Part 60 and all applicable portions of 40 CFR Parts 72 and 75.

46. Ensure that the NH_3 CEMS complies with the CEMS linearity check and Relative Accuracy Test Audit (RATA) frequencies and grace periods specified in 40 CFR Part 75 in conducting linearity checks and RATA’s. The relative accuracy (mean difference between the reference method values and the corresponding CEMS values) of the NH_3 CEMS shall be within the greater of +/- 15% of the approved NH_3 emission limits or +/- 0.75 ppmvdc or +/- 0.001 lb/MMBtu or lb/hr = +/- 0.001 lb/MMBtu x WA_MMBtu/hr, where WA_MMBtu/hr = the weighted average MMBtu/hr determined by the DAHS over the hours during which the RATA was performed.

47. In the event a given NH_3 CEMS RATA does not meet the relative accuracy specified in Proviso 44, proceed as follows:
a. PVEC shall investigate the possible reasons for a RATA failure and whether repairs or adjustments are necessary for the NH_3 CEMS or its sampling location/path. If such NH_3 CEMS repairs or adjustments are necessary prior to a successful RATA, or if sampling location/path adjustments are required, then the NH_3 CEMS data shall be considered invalid from the time of the failed RATA until a successful RATA occurs.
b. If no repairs or adjustments to the NH_3 CEMS are necessary between the time of a failed RATA and a successful RATA, and no sampling location/path adjustments are needed, then the NH3 CEMS data shall be considered valid during the period between the failed RATA and successful RATA.

48. Ensure that In the event data from the NH_3 CEMS is not available, corrective action is implemented as quickly as practical to bring the NH_3 CEMS back to service. During the time when the NH_3 CEMS is not available, PVEC may submit a parametric monitoring methodology to MassDEP for approval to provide assurance that the NOx levels, operating loads, and NH_3 injection rates being maintained are consistent with prior NH_3 compliant operation.</td></tr>
</table>

Table 13	
Emission Unit	**Recordkeeping Requirements**
CTG	PVEC shall 1. Maintain a log to record problems, upsets or failures associated with the emission control system, CEMs, temperature monitors, or NH_3 handling system. 2. Maintain records of all periods of excess emissions, even if attributable to an emergency/malfunction or startup/shutdown, and shall quantify these emissions and include them in the determination of annual emissions. 3. Maintain records of all measurements, performance evaluations, calibration checks, maintenance, and adjustments for each CEMS and temperature monitoring system device. 4. Maintain on-site permanent records of output from CEMS and temperature monitoring systems, and make these records available to the MassDEP on request. 5. Record for each unit on a daily basis the type(s) of fuel burned, heat content of each fuel, total heating value of the fuel consumed, and the actual emission rate for each pollutant for emission units demonstrating compliance with CEMS. 6. Demonstrate compliance for each new shipment of ULSD/Biodiesel received with the % sulfur-in-fuel requirement specified herein by testing certification or shipping receipt certification, either of which must certify that the shipment complies with the ASTM specifications for ULSD/Biodiesel and the specified % sulfur-in-fuel requirement. 7. Comply with all applicable record keeping requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, 310 CMR 7.28, 310 CMR 7.32, and 310 CMR 7.70. 8. Maintain for the life of the Facility all operating and monitoring records and logs. PVEC shall make available to the MassDEP for inspection upon request the five most recent years' data.

Table 14a

Emission Unit	**Reporting Requirements**
CTG	PVEC shall 1. Submit to the MassDEP, in a format acceptable to the MassDEP, a semi-annual report postmarked by January 31st and July 31st of each year, which minimally contains for the prior calendar 6-month period the following information: a. Reports from the Facility CEMS and temperature monitors, containing summary data, and b. For each period of excess emissions or excursions from allowable operating conditions, list the duration, cause (including whether it is attributable to a malfunction or emergency), the response taken, and the amount of excess emissions. Periods of excess emissions shall include periods of startups/shutdowns, malfunction, emergency, and upsets or failures associated with the emission control system, CEMS or temperature monitors. c. A tabulation of the time periods oil was fired and the number of gallons fired. 2. Comply with all applicable reporting requirements contained in 40 CFR Parts 72 and 75, 40 CFR 60, and 310 CMR 7.28.
Facility Wide	PVEC shall 3. Notify the EPA and MassDEP in writing within 48 hours of receiving a shipment of ULSD with a sulfur content in excess of 15 ppm by weight, and not combust that fuel.
Facility Wide	Emergency / Malfunction PVEC shall 4. Notify the MassDEP in writing within three (3) business days of any emergency or malfunction, when the emergency or malfunction may cause emissions to the ambient air that exceed any emission limits by 10% or more over the standard, including noise limits contained herein; or cause a condition of air pollution, or otherwise violate a term or condition of this approval. The written notice must contain a description of the emergency or malfunction, any steps taken to mitigate emissions, an estimate of the quantity of emissions released as a result of the emergency or malfunction and any corrective actions taken. 5. Notify the MassDEP within 24 hours by telephone and in writing within three (3) business days, following the release or the threat of a release of NH_3, and/or upsets or malfunctions to the NH_3 handling or delivery systems, and comply with all notification procedures required under M.G.L. c. 21 E - Spill Notification Regulations, and the Massachusetts Contingency Plan, 310 CMR 40.000. 6. If the initial notice was not provided within three (3) business days, have the burden of establishing that the initial notice was provided as soon as reasonably practical in any subsequent enforcement action.

Table 14b	
Emission Unit	**Reporting Requirements**
Facility Wide	Emergency / Malfunction PVEC shall 7. The reporting requirements of this Approval for an emergency or malfunction do not supersede, limit, or make inapplicable any reporting obligation under federal law, including but not limited to 42 U.S.C. sections 9603 or 11004. 8. An emergency and/or malfunction may constitute an affirmative defense to an action brought for non-compliance with emission limitations if PVEC demonstrates the affirmative defense of emergency or malfunction through properly signed, contemporaneous operating logs and other relevant evidence that shows that: a. an emergency or malfunction occurred and that the cause(s) of the emergency or malfunction can be identified; b. PVEC was, at that time, operating the Facility in a correct manner; c. during the period of the emergency or malfunction, PVEC took all reasonable steps as expeditiously as possible to minimize levels of emissions that exceeded the emission standards, or other requirements in this approval; and d. PVEC submitted notice of the emergency or malfunction to the MassDEP in writing within three (3) business days of the emergency or malfunction. The written notice must contain a description of the emergency or malfunction, any steps taken to mitigate emissions, an estimate of the quantity of emissions released as a result of the emergency or malfunction and any corrective actions taken.

Table 15-a	
Emission Unit	**Special Terms and Conditions**
CTG	PVEC shall 1. Only burn natural gas or ULSD/Biodiesel in the CTG. 2. Install, operate, and maintain a single, dedicated ASTM certified natural gas flow meter and a single, dedicated ASTM certified ULSD flow meter for monitoring the referenced fuel flows. 3. Comply with all applicable NSPS requirements for CTG found in 40 CFR Part 60, Subpart KKKK. 4. Ensure that the SCR control system is operational at all times the CTG is operating except periods of cold/warm startups, shutdowns, and malfunctions. 5. Ensure that the duration of cold startups is no greater than 5.0 hours, the duration of warm startups are no greater than 2.0 hours, and the duration of shutdowns are no greater than 1.0 hours. Cold startups are defined as occurring after a period of greater than 24 hours of turbine shutdown, and warm startups are defined as occurring after 24 hours or less since turbine shutdown. Shutdown is defined as the time when the turbine operation is between minimum sustained operating load and flame-out in the turbine combustor occurs. 6. Install and maintain a non-resettable operating hour meter or the equivalent software to accurately indicate the elapsed operating time of the combustion, including periods of when the unit is in startup and shutdown operations. 7. In addition to the ULSD combustion limitations imposed in Table 8 in the column “Restrictions”, only burn ULSD in the CTG during hours when one or more of the following conditions is true: a. The interruptible natural gas supply is curtailed at the Tennessee No. 6 gas terminal hub. A curtailment beings when PVEC receives a communication from the owner of the hub informing PVEC that the natural gas supply will be curtailed, and ends when PVEC receives a communication from the owner of the hub stating that the curtailment has ended. b. Any equipment (whether on-site or off-site) required to allow the CTG to utilize natural gas has failed; c. PVEC is commissioning the CTG and, pursuant to the CTG’s manufacturer’s written instructions, PVEC is required by the manufacturer to fire ULSD during the commissioning process; d. The firing of ULSD is required for emission testing purposes as specified herein or as required by EPA. e. Routine maintenance of any equipment requires PVEC to fire ULSD. f. In order to maintain an appropriate turnover of the on-site fuel oil inventory, PVEC may fire ULSD when the average age of the oil in the tank is greater than six months. A new waiting period for when oil can be used pursuant to this condition will commence once oil firing is stopped. 8. For purposes of provision 7.a. in Table 15-a (above), PVEC may designate an alternate gas terminal hub in lieu of the Tennessee No. 6 hub. Such an alternate designation will become effective when EPA receives PVEC’s written communication specifying PVEC’s alternate hub designation and shall remain effective until replaced by another alternate hub designation.

Table 15-b	
Emission Unit	**Special Terms and Conditions**
Emergency Engine & Fire Pump	PVEC shall 9. Ensure that the sulfur content at the time of purchase of oil to be used as fuel in the emergency generator & fire pump conforms with the then current sulfur limit applied to on-road specification oil as defined in the Code of Federal Regulations (at the time of issuance of this permit, defined in 40 CFR § 80.29(a)(i)). 10 Ensure that the emergency generator and fire pump are equipped with exhaust silencers, if necessary, so that sound emissions will not cause or contribute to a condition of air pollution. 11. Ensure that the emergency generator & fire pump utilize exhaust stacks that discharge in accordance with specifications provided in the air permit application air quality impact analysis so as to not cause a condition of air pollution (310 CMR 7.01(1)). Exhaust stacks shall be configured to discharge vertically and shall not be equipped with any part or device that restricts the vertical exhaust flow, including but not limited to rain protection devices. Any emission impacts of exhaust stacks upon sensitive receptors including people, windows and doors that open, and building fresh air intakes shall be minimized by employing good air pollution control engineering practices. Such practices includes avoiding locations that may be subject to downwash of the exhaust, and installing stacks of sufficient height in locations that will prevent and minimize flue gas impacts upon sensitive receptors. The minimum stack height shall be ten feet above the facility rooftop or the emergency engine enclosure, whichever is higher. 12. Install and maintain a non-resettable operating hour meter or the equivalent software on both the emergency engine and the fire pump to accurately indicate the elapsed operating time.
Auxiliary Boiler	PVEC shall 13. Install and maintain a non-resettable operating hour meter or the equivalent software to accurately indicate the elapsed operating time.
Facility-Wide	PVEC shall 14. Maintain at the Facility, properly maintained, operable, portable NH_3 detectors for use during an NH_3 spill, or other emergency situation involving NH_3 at the Facility. 15. Ensure that the NH_3 storage tank is equipped with high and low level audible alarm monitors. 16. Ensure that the diked area around the NH_3 storage tank is equipped with passive evaporative control (such as polyethylene balls) that, in the event of a spill, is capable of achieving at all times a minimum surface area reduction of 90% and is maintained free of ice/snow/leaves or anything else that could reduce its surface area reduction properties. 17. Ensure that the Facility complies with all applicable operational standards contained in 40 CFR Part 72 and 75, 40 CFR 60, 310 CMR 7.28, 310 CMR 7.32, and 310 CMR 7.70. 18. Properly train all relevant personnel to operate the Facility monitoring and control equipment in accordance with vendor specifications and all applicable regulations. This training shall be updated at least once annually. Ensure that MassDEP personnel are informed of scheduled training sessions at least 30 days in advance and ensure that MassDEP personnel are allowed access to attend these training sessions. 19. Ensure that, due to safety concerns and to minimize greenhouse gas impacts, natural gas is not used for cleaning or removing debris from the natural gas pipeline prior to commissioning, but instead will use compressed air, nitrogen, mechanical means, or any recommended safer alternative specified by the U.S. Chemical Safety Board.

Appendix A

Pioneer Valley Energy Center, LLC, Westfield
Industrial Sewer User Permit, Transmittal No. X232475 and
Air Quality Conditional Approval, Transmittal No. X223780

FINDING PURSUANT TO M.G.L. CHAPTER 30, SECTION 61
Project Name: Pioneer Valley Energy Center
Project Location: Westfield, Massachusetts
Project Proponent: Pioneer Valley Energy Center, LLC
EOEEA Number: 14151
Permits Sought: Industrial Sewer User and Air Quality

I. Project Description

Pioneer Valley Energy Center, LLC (the Proponent or PVEC) proposes to develop an electric energy generating facility (the Facility) on a vacant site located on Ampad Road in Westfield, Massachusetts (the Site). The Site consists of three parcels totaling approximately 44 acres of largely undeveloped land and is located approximately one mile north of the Massachusetts Turnpike and three-quarters of a mile west of U.S. Route 202. Electric energy will be produced using a combustion turbine and heat recovery steam generator (HRSG) operating in a combined cycle configuration. Cooling water for the system will be provided by an evaporative wet cooling tower.

Wastewater discharges from the HRSG and cooling tower, along with miscellaneous activities such as periodic equipment cleaning will exceed 50,000 gallons per day, requiring the Facility to obtain a sewer connection permit from the Massachusetts Department of Environmental Protection (MassDEP). Wastewater will be discharged to the Westfield Wastewater Treatment Facility, a Publicly Owned Treatment Works (POTW) owned and operated by the City of Westfield.

PVEC's air emitting sources include a combustion turbine-generator, an auxiliary boiler, an emergency engine-generator, and an emergency engine-fire pump. Potential air emissions of nitrogen oxide (NOx) exceed the major source threshold, making PVEC subject to review under MassDEP's Non-attainment Review Regulations at 310 CMR 7.00, Appendix A. Accordingly, PVEC is required to obtain a Major Comprehensive Plan Application Approval from MassDEP to ensure that the emissions of NOx meet the Lowest Achievable Emission Rate (LAER) criteria and to obtain offsets in a ratio of 1.26 to 1 for the amount of NOx emitted by the Facility.

Also, PVEC's potential air emissions of nitrogen dioxide (NO_2) exceed the EPA's Prevention of Significant Deterioration (PSD) applicability threshold. Accordingly, PVEC is required to obtain a PSD permit from EPA in accordance with the PSD Regulations at 40 CFR Part 52.21and which requires the application of Best Available Control Technology (BACT) for all attainment pollutants with potential emissions above the

Significance Emission Rates defined in the PSD Regulations. PVEC submitted a PSD permit application to the EPA on November 24, 2008.

II. MEPA History

Pursuant to M.G.L. c. 30, §61 and 62 A-H of the Massachusetts Environmental Policy Act (MEPA) and its implementing regulations (301 CMR 11.00), an Environmental Notification Form (ENF) for the Project was submitted to the MEPA Office on November 30, 2007. The Secretary of the Executive Office of Energy and Environmental Affairs (the Secretary) issued a Certificate on the ENF on January 23, 2008, with the determination that the Project required the preparation of a mandatory Environmental Impact Report (EIR).

A Draft EIR (DEIR) for the Project was submitted to the MEPA Office on August 15, 2008, which addressed the Secretary's Scope and comments received on the ENF. The Secretary issued a Certificate on the DEIR on October 17, 2008, with the determination that the DEIR adequately and properly complied with MEPA and its implementing regulations. The DEIR Certificate for the Project directed the Proponent to prepare and submit for review a Final EIR (FEIR). A FEIR for the Project was submitted to the MEPA Office on January 15, 2009, which addressed the Secretary's Scope and comments received on the DEIR. On March 6, 2009, the Secretary issued a Certificate on the FEIR which determined that the FEIR adequately and properly complies with MEPA and its implementing regulations.

III. Project Impacts

a. Wastewater:

Wastewater will be generated from periodic equipment washing and sanitary sources, along with blow-down water from the cooling tower and HRSG. Water consumed by the combustion turbine for emissions control will be discharged in vapor phase in the turbine exhaust. The media used in the water purification systems will be regenerated (cleaned) off-site, which will minimize on-site chemical use and wastewater discharges. All wastewater generated on-site and sanitary waste from the Facility's personnel will be discharged to the municipal sewer system that runs along Ampad Road for treatment at the municipal wastewater treatment facility (WWTF). The typical wastewater discharge rate from the Facility is expected to be less than 230,000 gallons per day, with a peak wastewater discharge rate of up to approximately 340,000 gallons per day during periods of ULSD firing.

According to the 2001 modification of the WWTF's NPDES Permit, it is authorized to discharge up to 6.1 MGPD of treated wastewater to the Westfield River. Available records indicate that the average daily discharge from the treatment plant from 2005 through 2007 was approximately 4 MGPD. Therefore, the maximum wastewater discharge from the Facility represents only 16% of the WWTF's permitted available capacity, on an annual daily average basis. The City of Westfield has confirmed that its sewer system has the infrastructure and capacity to handle the wastewater discharge from the Facility. An approval/permit to discharge wastewater has been issued to PVEC by the City of Westfield POTW.

b. Air Emissions:
At maximum operation, primary emissions to the ambient atmosphere from the Facility, including the emissions from startups and shutdowns, will consist of 51 tons per year (tpy) of particulate matter, 18 tpy of sulfur dioxide, 111 tpy of nitrogen oxides, 550 tpy of carbon monoxide, 29 tpy ammonia, 24.8 tpy of volatile organic compounds and 18 tpy of sulfuric acid mist.

Additionally, because of the requirement that the Facility's NOx emissions be controlled at the Lowest Achievable Emission Rate, the total annual NO_x emissions from the Facility must also be offset by an equal or greater reduction in the actual emissions of NO_x from other sources. The ratio of total actual emission reductions to the increase in actual emissions must be at least 1.26:1 (a 1.2:1 offset ratio coupled with a 5% public benefit set aside).

The results from the air quality impact analysis have demonstrated that the Facility's air emissions associated with the construction and operation of the source will comply with the applicable National Ambient Air Quality Standards and the MassDEP's air toxics limits for non-criteria pollutants.

IV. Project Mitigation Measures

a. Wastewater:
The WWTF's draft NPDES Permit includes discharge limitations for several pollutants, including chlorine, nitrogen, and specified metals. Compliance with these limitations is demonstrated though routine effluent sampling. The draft NPDES Permit requires the WWTF to develop and enforce specific effluent limits for all sewer users that are necessary to ensure continuous compliance with the permit.

To meet the requirements of the NPDES Permit, the City of Westfield WWTF will establish pollutant threshold limits and other limitations to all users of the system, including PVEC. PVEC will require a Sanitary Sewer Permit from the City of Westfield for its wastewater discharge. This Permit includes pollutant threshold limits and effluent sampling requirements for the Facility to help assure that the WWTF can maintain compliance with its NPDES Permit. PVEC will abide by all of the provisions of its Sanitary Sewer Permit, including its effluent sampling requirements, to ensure compliance with the pollutant threshold limits.

The Facility will discharge its wastewater to the Westfield sewer system in accordance with the limitations specified in its Sanitary Sewer Permit, which typically, among other things, include temperature limits. Such limits are typically prescribed to protect the sewer system infrastructure. The Facility will utilize continuous temperature monitoring of the discharge, with alarms to the Operations Control Room, which is staffed around-the-clock. Further, the Facility will utilize a blowdown cooling system to remove excess heat from the warmer parts of the discharge system before the flow is combined with the balance of the plant discharge. With these control measures in place, the temperature of the wastewater entering the WWTF will not be impacted by the Facility's discharge. There will be no direct discharge of Facility wastewater to the Westfield River, or to any wetlands or rare habitat areas. Because its discharge will be sent directly to the WWTF for treatment, the Facility wastewater will not have any thermal impact on discharges to the Westfield River, or any wetlands or rare habitat areas. In addition, through a required sampling and monitoring program for other pollutants of concern, PVEC is obligated to ensure that its wastewater discharges to the WWTF are in compliance with its local permit's terms and conditions.

b. Air Emissions:
PVEC is proposing to burn natural gas and ultra low sulfur distillate (ULSD) oil to generate power, generally regarded as the cleanest gaseous and liquid fuels that are available in the quantities necessary to operate a facility of this size.

The emissions of NOx from the combustion turbine-generator and heat recovery steam generator will be limited to the equivalent of Lowest Achievable Emission Rate (LAER). This will be achieved by using dry, low-NOx combustors while firing natural gas; water injection while firing ultra low sulfur distillate/biodiesel oil; and by using selective catalytic reduction (SCR) add-on control technology to further lower NOx emissions.

Additionally, PVEC has acquired 143 tons of NOx emission reduction credits from NSTAR Electric and Gas Corporation, One NSTAR Way, Westwood, MA 02090, and from Osram Sylvania Products, Inc., 100 Endicott Street, Danvers, MA 01923 to fully offset the Facility's NO_x emissions by the required ratio of 1.26 to 1.

PVEC is also required to obtain PSD permit from EPA, in accordance with the PSD Regulations at 40 CFR Part 52.21 and which requires the application of Best Available Control Technology (BACT) for all attainment pollutants with potential emissions above the Significance Emission Rates defined in the PSD Regulations; namely NO_2, CO, PM, PM_{10}, $PM_{2.5}$ and H_2SO_4. PVEC submitted a PSD application to the EPA on November 24, 2008.

V. Overview of Project Impacts relating to the permit applications submitted to MassDEP
Potential impacts from the PVEC project are defined as either construction or post-construction and grouped by issue areas that are the subject of the applications reviewed and the permits issued by MassDEP.
The issue areas are:

- Air Quality — Construction
- Air Quality — Operation
- Greenhouse Gas Emissions
- Noise
- Wastewater

Based upon the Environmental Impact Reports and the review of the record, MassDEP finds that the implementation of the requirements of its permits constitute all feasible measures to avoid damage to the environment and will minimize and mitigate damage to the environment to the maximum extent practicable, within the subject of the required permits.

TABLE OF MITIGATION MEASURES AND FUNDING RESPONSIBILITY

EIR Category	Impact	Mitigation	Funding Responsibility	Schedule
Air Quality	Construction air quality	Minimize fugitive dust emissions using the following mitigation measures: • Water construction areas, access roads, and staging areas as needed; • Cover trucks hauling soils and other loose materials; • Cover stockpiles of soils and other excavated materials; • Pave access roads when possible; • Limit vehicles to 15 mph on unpaved roads; and • Install wind breaks on the windward sides of construction areas.	PVEC Estimated cost: n/a	Construction Period
		Minimize emissions from diesel equipment and vehicles using the following measures: • Use ULSD fuel in all off-road construction equipment; • Minimize vehicle idling time; and • Equip diesel engines with DOC or DPF.	PVEC Estimated cost: n/a	Construction Period
	Operational air quality	Use of clean-burning natural gas as the primary fuel and ULSD as the backup fuel for up to the equivalent fuel usage of 1,440 hours per year at maximum firing rate.	PVEC Estimated cost: n/a	During Operation
		Implement LAER for NO_x emissions and BACT for all regulated pollutants using SCR, OC, and state-of-the-art combustion design and controls.	PVEC Estimated cost: n/a	During Operation
		Offset NO_x emissions by at least a 1.26:1 ratio.	PVEC Estimated cost: n/a	Prior to MassDEP Air Plan Approval
		Comply with NSPS emissions standards and other applicable requirements.	PVEC Estimated cost: n/a	During Operation
Greenhouse Gas Emissions	Operational air quality	Acquire CO_2 allowances and otherwise meet the applicable requirements of the MassDEP CO_2 Budget Trading Program	PVEC Estimated cost: $4,000,000	Annually
		Implement building and design GHG mitigation measures including high- efficiency HVAC systems, elimination or reduction of refrigerants, window glazing, super insulation, and motion sensors.	PVEC Estimated cost: n/a	During Operation
		Submit a feasibility analysis for the installation of a water turbine in the cooling water supply line. Work with MassDEP to implement the proposal or select an alternative, comparable mitigation project.	PVEC Estimated cost: n/a	Prior to MassDEP Air Plan Approval
		Continue to explore and report back to MassDEP on the potential for biofuel use and turbine performance.	PVEC Estimated cost: n/a	During Operation
		Provide certification to MEPA that all proposed GHG mitigation measures, or other equivalent measures, have been incorporated into the project.	PVEC Estimated cost: n/a	Following Construction
Noise	Construction Noise Impacts	Further evaluate noise levels associated with proposed HDD operations. Prepare a conceptual mitigation plan including temporary noise barrier walls, and partial equipment enclosures. Conduct noise monitoring for compliance.	PVEC Estimated cost: n/a	Construction Period

EIR Category	Impact	Mitigation	Funding Responsibility	Schedule
	Operational Noise Impacts	Implement comprehensive noise mitigation measures including high performance silencers, acoustic shrouds and enclosures, noise barrier walls, a building to enclose major components.	PVEC Estimated cost: n/a	During Operation
		Comply with MassDEP noise criteria limits at all residential receptor locations. Satisfy the MassDEP pure tone criteria at all property line and residential receptors. Obtain a waiver from MassDEP from the noise criteria limits at one property line location.	PVEC Estimated cost: n/a	During Operation
Wastewater	Environmental Impacts from wastewater discharge	Do not directly discharge wastewater to the Westfield River, or to any wetland resource area or rare habitat areas	PVEC Estimated cost: n/a	During Operation
		Comply with the terms and conditions of the Sanitary Sewer Permit from the City of Westfield and MassDEP's Industrial Sewer User Permit for wastewater discharge, including pollutant threshold limits and effluent sampling requirements.	PVEC Estimated cost: n/a	During Operation
		Use continuous temperature monitoring of the discharge and a blowdown cooling system to remove excess heat from the warmer parts of the discharge system prior to combining with flows from the balance of the Facility.	PVEC Estimated cost: n/a	During Operation

VI. Findings

Pursuant to Section 61 of the Massachusetts Environmental Policy Act, M.G. L. c.30 §§ 61-62H, inclusive, (MEPA); 301 CMR 11.12 of the MEPA Regulations; and the Secretary's Certificate on the Final EIR dated March 6, 2009 (EOEA #14151), MassDEP finds, based on its review of the MEPA documents and the application materials submitted, that feasible measures will be taken to avoid damage to the environment, and where damage to the environment cannot be avoided, that all practicable measures will be implemented to prevent or minimize adverse impacts to air quality and the environment, and to the Westfield wastewater treatment system infrastructure. MassDEP will include appropriate conditions within the air quality conditional approval and the sewer user permit to assure compliance with the mitigation measures discussed above.

Appendix B

Table B-1
Noise Prediction Results

Site No.	Address	Existing Ambient L_{90}, dBA	Predicted Noise Level (Plant+Ambient) L_{eq}, dBA	Noise Increase (dBA)
PL-1	Property Line: Edge of Ampad Road across from Ampad Trucking Co.	41	54	+13*
PL-2	Property Line: Ampad Road and Servistar Industrial Way, behind American Canvas Company	42	51	+9
PL-3	Property Line: Wooded area along power line right-of-way	40	58	+18**
PL-4	Property Line: Near Servistar Industrial Way& Egleston Road, behind Custom Wood Products Company	40	47	+7
PL-5	Property Line: Edge of Servistar Industrial Way across from Lowes Distribution Warehouse	43	47	+4
RES-1	Residence: at 1 Williams Way	33	38	+5
RES-2	Residence: at 47 Barbara Street	37	39	+2
RES-3	Residence: at 21 West Glen Road	41	43	+2
RES-4	Residence: at 323 Lockhouse Street	37	40	+3

* Release from the requirements of MassDEP noise policy obtained from affected property owners by project proponent.

** No release was sought at PL-3 since that location, coinciding with a power line right-of-way, is not buildable and not a potential sensitive receptor.

Table B-2
Comparison of Project Impacts to SILs and NAAQS

Pollutant	Averaging Period	NAAQS (ug/M³)	Significant Impact Level (ug/M³)	Maximum Project Impacts (ug/M³)	Maximum Project Impacts % of SIL	Background Concentrations (ug/M³)	Total Predicted Ambient Concentrations (ug/M³)	Total Predicted Ambient Concentrations % of NAAQS
CO	1-hr	40,000	2000	104.2	5%	3843	3947	10%
	8-hr	10,000	500	18.2	4%	3028	3046	30%
NO_2	Annual	100	1	0.6	60%	19.1	20	20%
	1-hr	189	n/a	86.2	n/a	79.2	165	88%
PM_{10}	24-hr	150	5	1.9	38%	53	55	37%
$PM_{2.5}$	24-hr	35	2	1.9	95%	28.3	30	86%
	Annual	15	0.3	0.2	67%	10.0	10	67%
SO_2	3-hr	1300	25	2.0	8%	99	101	8%
	24-hr	365	5	0.4	8%	56	56	15%
	Annual	80	1	0.04	4%	16	16	20%

Table B-3
Comparison of Project Concentrations to PSD Increments

Pollutant	Averaging Period	PSD Increment (ug/M^3)	Maximum Project Impacts (ug/M^3)	% PSD Increment
NO_2	Annual	25	0.6	2.4
PM_{10}	24-hr	30	1.9	6.3
	Annual	17	0.2	1.2
SO_2	3-hr	512	2.0	0.4
	24-hr	91	0.4	0.4
	Annual	20	0.04	0.2

Table B-4
Stack Dimensions of Fuel Burning Equipment

	CTG	Auxiliary Boiler	Emergency Generator	Fire Pump
Stack Height	180. feet	125. feet	130. feet	25. feet
Stack Diameter	23. feet	2. feet	0.67 feet	0.67 feet
Stack Area	415.48 ft^2	3.14 ft^2	0.35 ft^2	0.35 ft^2

Table B-5
CTG Exhaust Parameters (Natural Gas)

Load (%)	100	100	100	75	75	75	60	60	60
Ambient Temp (°F)	10	59	90	10	59	90	10	59	90
Exhaust Flow (acfm)	1,429,900	1,299,800	1,227,500	1,142,500	1,058,800	1,017,200	956,800	887,800	869,900
Exit Velocity (ft/sec)	57.36	52.14	49.24	45.83	42.47	40.80	38.38	35.61	34.90
Exhaust Temp (°F)	177.4	175.2	181.1	174.1	173	180.4	166.1	164	172.7
NOx (lb/hr)	20.2	18	16.7	15.7	14.2	13.3	13.5	12.3	11.5
CO (lb/hr)	12.3	11	10.2	9.6	8.7	8.1	8.2	7.5	7
SO_2 (lb/hr)	4.7	4.2	3.9	3.6	3.3	3.1	3.1	2.9	2.7
PM_{10} (lb/hr)	9.8	8.8	8.1	7.7	7.1	6.6	6.6	6.1	5.7
$PM_{2.5}$ (lb/hr)	9.8	8.8	8.1	7.7	7.1	6.6	6.6	6.1	5.7

Table B-6
CTG Exhaust Parameters (ULSD/Biodiesel)

Load (%)	100	100	100	75	75	75	60	60	60
Ambient Temp (°F)	10	59	90	10	59	90	10	59	90
Exhaust Flow (acfm)	1582800	1414300	1331200	1266100	1097500	1055500	1155400	932900	902900
Exit Velocity (ft/sec)	63.49	56.73	53.40	50.79	44.03	42.34	46.35	37.42	36.22
Exhaust Temp (°F)	224.7	208.8	213.6	214.5	197.3	203.5	214.7	190.5	196.4
NOx (lb/hr)	43	42.7	39.3	34.3	34.1	32	29.7	29.8	28
CO (lb/hr)	31.5	31.2	28.8	25.1	24.9	23.4	21.7	21.8	20.5
SO_2 (lb/hr)	3.4	3.4	3.1	2.8	2.7	2.6	2.4	2.4	2.3
PM_{10} (lb/hr)	26.8	24.8	22.8	21.7	19.7	18.4	19.6	17	16
$PM_{2.5}$ (lb/hr)	26.8	24.8	22.8	21.7	19.7	18.4	19.6	17	16

Table B-7
Aux. Boiler, Emergency Gen., & Fire Pump Exhaust Parameters – (ULSD/Biodiesel)

Source	Auxiliary Boiler			Emergency Generator	Fire Pump
Load (%)	100	80	60	100.	100
Exhaust Flow (acfm)	7,917	6,334	4,750	11,061.	1,908
Exit Velocity (ft/sec)	42.00	33.60	25.20	528.10	91.10
Exhaust Temp (°F)	410	410	410	763.5	737
NOx (lb/hr)	0.61	0.488	0.366	37.47	3.21
CO (lb/hr)	0.78	0.624	0.468	12.20	0.25
SO_2 (lb/hr)	0.01	0.0088	0.0066	0.08	0.007
PM_{10} (lb/hr)	0.10	0.08	0.06	0.91	0.09
$PM_{2.5}$ (lb/hr)	0.10	0.08	0.06	0.91	0.09

Table B-8
Summary of CTG BACT/LAER Determination

Pollutant	Fuel	Proposed Stack Concentration	Proposed Emission Rate	Proposed Control Technology
NO_x LAER	natural gas	2.0 ppmvd @ 15% O_2		Dry Low-NOx Combustion Selective Catalytic Reduction
SO_2 BACT	natural gas		0.0019 lb/MMBtu	Natural Gas Fuel
H_2SO_4 BACT	natural gas		0.0019 lb/MMBtu	Natural Gas Fuel
Turbine PM/PM_{10} BACT	natural gas		0.0040 lb/MMBtu	Natural Gas Fuel
Cooling Tower PM/PM_{10} BACT	natural gas		0.010 lb/hr	Drift Eliminator (0.0005%)
CO BACT	natural gas	2.0 ppmvd @ 15% O_2		Oxidation Catalyst
VOC BACT	natural gas	1.0 ppmvd @ 15% O_2		Oxidation Catalyst
NH_3 BACT	natural gas	2.0 ppmvd @ 15% O_2		
NO_x LAER	ULSD / Biodiesel	5.0 ppmvd @ 15% O_2		Water Injection Selective Catalytic Reduction
SO_2 BACT	ULSD / Biodiesel		0.00017 lb/MMBtu	ULSD/Biodiesel Fuel
H_2SO_4 BACT	ULSD / Biodiesel		0.0018 lb/MMBtu	ULSD/Biodiesel Fuel
Turbine PM/PM_{10} BACT	ULSD / Biodiesel		0.014 lb/MMBtu	ULSD/Biodiesel Fuel
Cooling Tower PM/PM_{10} BACT	ULSD / Biodiesel		0.010 lb/hr	Drift Eliminator (0.0005%)
CO BACT	ULSD / Biodiesel	6.0 ppmvd @ 15% O_2		Oxidation Catalyst
VOC BACT	ULSD / Biodiesel	6.0 ppmvd @ 15% O_2		Oxidation Catalyst
NH_3 BACT	ULSD / Biodiesel	2.0 ppmvd @ 15% O_2		