Bridgeport Peaking Station
Bridgeport, CT

Permit to Construct Application

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EXECUTIVE SUMMARY

Bridgeport Energy II, LLC (BEII) is proposing to build and operate a new 350 MW nominal simple cycle combustion turbine generating facility in Bridgeport, CT. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. The project will be called the Bridgeport Peaking Station (BPS). The new facility will be located south of the existing Bridgeport Energy facility on a parcel of land adjacent to the western boundary of the existing Bridgeport Harbor Station property. The BEII facility will be owned and operated separately from the existing Bridgeport Energy generating station.

The Project will utilize either two (2) General Electric (GE) model 7FA or two Siemens model SGT6-5000F turbines. BEII is currently evaluating the availability and cost of these turbine models but has not yet made a final decision on turbine technology. Accordingly, this application presents information for both turbine models. BEII will provide the Connecticut Department of Environment Protection (CTDEP) with the selected turbine model prior to commencing construction.

BEII is proposing to limit total annual operating hours and annual hours firing ULSD, and proposes to install selective catalytic reduction (SCR) to minimize NO_x emissions. The application of these operation and pollution controls will limit emissions of all pollutants below the Prevention of Significant Deterioration (PSD) major source thresholds with the exception of CO and NO_x. BPS will also be a non-attainment new source review (NNSR) new major source for NO_x emissions with potential emissions above 25 tons per year (tpy).

The NNSR regulations require that a new major source install Lowest Achievable Emission Rate (LAER) technology to reduce emissions to the lowest level technically feasible. Therefore, BEII has proposed to install SCR on the turbines to achieve the lowest NO_x emissions of any simple-cycle "F" class turbine operating in the United States. Additionally, CTDEP regulations require the application of Best Available Control Technology (BACT) for all pollutants with a potential to emit above 5 tpy. A BACT analysis is also provided for emissions of sulfur dioxide (SO_2), particulate matter ($PM/PM_{10}/PM_{2.5}$), carbon monoxide (CO), volatile organic compounds (VOCs) and ammonia (NH_3).

The two proposed combustion turbines will comprise the two primary air pollutant emission sources from the project. BPS will also include a 1.2 million gallon backup fuel oil tank that will have minor VOC emissions. The project will not include any supporting diesel fired emergency engines or cooling towers.

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LIST OF ACRONYMS

Acronym	Definition
$\mu g/m^3$	microgram per cubic meter
AAQS	Ambient Air Quality Standard
BACT	Best Available Control Technology
BEII	Bridgeport Energy II, LLC
BPIP	Building Profile Input Program
BPS	Bridgeport Peaking Station
Btu/hr	British thermal units per hour
Btu/kW	British thermal units per kilowatt
Btu/kWh	British thermal units per kilowatt-hour
CAAA	Clean Air Act Amendment
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTDEP	Connecticut Department of Environmental Protection
DLN	Dry Low NO_x
EPA	U.S. Environmental Protection Agency
ERCs	Emission Reduction Credits
g/s	grams per second
H_2O	Water
H_2SO_4	Sulfuric Acid Mist
Km	Kilometer
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
LAER	Lowest Achievable Emission Rate
M	Meter
MACT	Maximum Available Control Technology
MASC	Maximum Allowable Stack Concentration
m/s	Meters per second
MMBtu	Million British Thermal Units
MMBtu/hr	Million British thermal units per hour
Msl	Mean Sea Level
MW	Megawatt
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NH_3	Ammonia
$(NH_4)SO_4$	Ammonium Sulfate Salts
NMHC	Non-Methane Hydrocarbon
NNSR	Non-attainment New Source Review
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
NSR	New Source Review

LIST OF ACRONYMS

Acronym	Definition
O_2	Oxygen
OC	Oxidation Catalyst
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter with a diameter of 10 microns or less
$PM_{2.5}$	Particulate Matter with a diameter of 2.5 microns or less
Ppm	Parts per million
Ppmvd	Parts per million volume dry
Ppmw	Parts per million weight
PSD	Prevention of Significant Deterioration
RBLC	RACT/BACT/LAER Clearinghouse
RH	Relative humidity
SCF	Standard cubic feet
SCR	Selective Catalytic Reduction
Sec	Second
Sf	Square feet
SIC	Standard Industrial Classification
SILs	Significant Impact Levels
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SUSD	Startup/Shutdown
Tpy	Tons per year
ULSD	Ultra Low Sulfur Diesel fuel oil
USGS	United States Geological Survey
VOC	Volatile Organic Compounds

1. INTRODUCTION

BEII Development, LLC is proposing to build and operate a new 350 MW nominal simple cycle combustion turbine generating facility in Bridgeport, CT. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. The project will be called the Bridgeport Peaking Station (BPS). The new facility will be located south of the existing Bridgeport Energy facility on a parcel adjacent to the western boundary of the existing Bridgeport Harbor Station property. The BEII facility will owned and operated separately from the existing Bridgeport Energy generating station.

The Project will utilize either two (2) General Electric (GE) model 7FA or two Siemens model SGT6-5000F turbines. These are "F" Class turbines that utilize specialty materials for a higher hot gas path temperature resulting in higher generating capacities and efficiencies. BEII is currently evaluating the availability and cost of these turbine models but has not yet made a final decision on turbine technology. Accordingly, this application presents information for both turbine models. In preparing the permit application, a "worst-case hybrid" approach was employed to determine potential emissions and inputs for modeling. BEII will provide the Connecticut Department of Environment Protection (CTDEP) with the selected turbine model prior to commencing construction.

BEII is proposing to limit total annual operating hours and annual hours firing ULSD, and proposes to install selective catalytic reduction (SCR) to minimize NO_x emissions. The project will be a new major source for emissions of nitrogen oxides (NO_x) and carbon monoxide (CO). Additionally, potential emissions of particulate matter (PM/PM_{10}) will exceed its significant emission rate. Accordingly, the proposed project will be subject to Prevention of Significant Deterioration (PSD) review for these pollutants. Since the project is located in a non-attainment area for ozone, it will be subject to non-attainment new source review (NNSR) for NO_x emissions.

The NNSR regulations require that a new major source install Lowest Achievable Emission Rate (LAER) technology to reduce emissions to the lowest level technically feasible. Therefore, BEII has proposed to install SCR on the turbines to achieve the lowest NO_x emissions of any simple-cycle "F" class turbine operating in the United States. Additionally, CTDEP regulations require the application of Best Available Control Technology (BACT) for all pollutants with a potential to emit above 5 tpy. A BACT analysis is also provided for emissions of sulfur dioxide (SO_2), particulate matter ($PM/PM_{10}/PM_{2.5}$), carbon monoxide (CO), volatile organic compounds (VOCs) and ammonia (NH_3).

The two proposed combustion turbines will comprise the two primary air pollutant emission sources from the project. BPS will also include a 1.2 million gallon backup fuel oil tank that will have minor VOC emissions. The project will not include any supporting diesel fired emergency engines or cooling towers.

This application is divided into four sections, including this Introduction, and three appendices containing supporting material. The air dispersion modeling analysis associated with this application will be submitted under separate cover. The information provided meets all of the applicable CTDEP New Source Review (NSR) permit application requirements.

The application is organized as follows:

- Section 2 - Project Description & Emissions
- Section 3 - Regulatory Applicability & Compliance Analysis;
- Section 4 - BACT Analysis;
- Appendix A - CTDEP Permit Application Forms;
- Appendix B - Supporting Calculations for Emission Rates and BACT Analysis;
- Appendix C - Preliminary Site Plan and Elevation Drawings.

EarthTech

Portion of Bridgeport USGS 7.5' quadrangle.
Scanned image provided by CT DEP.

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Feet

Figure 1
Site Locus Map

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2. PROJECT DESCRIPTION & EMISSIONS

2.1 Project Description

The Project will utilize either two (2) General Electric (GE) model 7FA or Siemens model SGT6-5000F turbines operating in simple-cycle (peaking) mode. The turbines will have a collective nominal generating capacity of approximately 350 MW. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. Commercial operation is scheduled to commence in 2008.

The simple-cycle turbines will utilize state-of-the-art dry low NO_x (DLN) combustors to minimize emissions from the project, prior to any post-combustion control. The proposed operating limitations for the facility also reduce potential annual emissions. These limitations include: annual operating hours of ≤2,500 hours per year (hr/yr) per turbine; ≤500 hours per year (hr/yr) of backup oil firing (400 hr/yr for the SGT6-5000F); and using ULSD as the backup fuel with a maximum sulfur content of 15 ppmw. An SCR control system will be incorporated to reduce NO_x emissions and meet LAER requirements. Due to the application of SCR, there will be some ammonia emissions (i.e. "ammonia slip") associated with the project. The station is also proposing to restrict normal operation to turbine loads that achieve permit limits, and to limit the number of starts per year to 250 per turbine (200 starts per year for the SGT6-5000F) to minimize emissions during startup and shutdown (SUSD) operation.

As outlined in Section 2.0, the primary emission sources will be the two combustion gas turbines. Emissions from the turbines were estimated for both typical operations and start-up/shutdown conditions. VOC emissions from the backup fuel oil tank were estimated but do not contribute significantly to total project emissions.

2.2 Baseload Emissions

The combustion turbine manufacturers provided emission rate data for all criteria pollutants during normal operation. Normal operation has been defined as all operating modes above 50% load for which permit limits can be achieved, AND with the SCR catalyst at its minimum operating temperature. From the emissions data and the estimated control efficiencies of the SCR, stack emissions of NO_x, CO, VOC, SO_2 and $PM/PM_{10}/PM_{2.5}$ were calculated. SO_2 emissions were calculated using fuel consumption rates provided by the turbine vendors in combination with the estimated maximum sulfur content of the natural gas (0.5 grains/100 scf) and ULSD (15 ppmw).

Maximum hourly emission rates for each pollutant were established after reviewing the vendor data over the range of potential ambient temperatures and proposed operating loads. Emission rates are specified at three standard (ASTM) ambient temperatures: 3°F, 59°F and 94°F. These temperatures are representative of the range of expected conditions at Bridgeport. The climatological mean annual temperature at Bridgeport is 52°F; maximum daily temperatures exceed 90°F for an average of only 6 days per year, while minimum daily temperatures do not go below 0°F in an average year. Table 2-1 presents a summary of the maximum hourly emission rates for the turbines (worst case for either turbine model). Detailed emissions data for each turbine are provided in Appendix B.

Table 2-1: Criteria Pollutant Maximum Emission Rates Per Turbine

Natural Gas Firing			
	3°F	**59°F**	**94°F**
NO_x, ppmvd at 15% O_2	3.0	3.0	3.0
NO_x, lb/hr	25.0	23.0	21.0
CO, ppmvd at 15% O_2	8.0	8.0	8.0
CO, lb/hr	36.0	33.0	31.0
VOC, ppmvd at 15% O_2	1.10	1.10	1.10
VOC, lb/hr	3.4	3.1	3.0
SO_2, lb/hr	2.6	2.3	2.2
$PM/PM_{10}/PM_{2.5}$, lb/hr	15.0	15.0	15.0
ULSD Firing			
	3°F	**59°F**	**94°F**
NO_x, ppmvd at 15% O_2	15.0	15.0	15.0
NO_x, lb/hr	125	114	107
CO, ppmvd at 15% O_2	16.0	16.0	16.0
CO, lb/hr	80	75	70
VOC, ppmvd at 15% O_2	4.60	4.60	4.60
VOC, lb/hr	15.0	13.5	12.6
SO_2, lb/hr	3.3	3.0	2.8
$PM/PM_{10}/PM_{2.5}$, lb/hr	60.0	60.0	60.0

BEII has evaluated the anticipated maximum dispatch of the facility. Based upon this evaluation, the maximum annual operating hours for each turbine are projected to be no greater than 2,500 hr/yr. Within this limit on annual operating hours, the project is proposing to limit ULSD firing to no greater than 500 hr/yr per turbine (400 hr/yr for the Siemens SGT6-5000F).

Potential emissions from the combustion turbines were estimated based upon a worst-case operating scenario developed using the expected maximum dispatch of the turbines. The potential emissions from each turbine must also incorporate any increase during startup and shutdown (SUSD) operation. Section 2.3 discusses SUSD emissions, and Section 2.4 provides a summary of estimated potential criteria pollutant emissions from the project taking into account baseload and SUSD operation. The specific scenario used for calculating potential emissions for each pollutant is provided in Appendix B.

2.3 Start-up/Shutdown Emissions

The plant will be operate as a "peaking" plant meaning that it will operate during periods of peak demand, which are generally during weekdays with high or low ambient temperatures. Consequently, the turbines may be turned on and off on a daily basis. Under this operating scenario, the turbines would be started up and shut down each weekday. Accordingly, the project estimates that the maximum number of starts, and associated shutdowns, per year will be 250 (200 per year for the Siemens SGT6-5000F).

Emissions of NO_x, CO and VOC from combustion turbines may be significantly higher during start-up and shutdown (SUSD) conditions than during normal operation. During start-up, the turbines cannot initially operate in lean pre-mix mode which results in higher emissions. A similar transition from lean pre-mix combustion to standard combustion occurs during shutdown. Also, the SCR catalyst is not effective until it reaches a minimum temperature of about 500°F. To account for this potential increase in emissions, an analysis was conducted to estimate emissions for SUSD and their impact on facility-wide potential annual emissions.

The duration of startups and shutdowns for a combustion turbine in simple-cycle mode is relatively short. Data was provided by each of the turbine vendors to quantify the NO_x, CO, and VOC emissions during a startup/shutdown event and its duration. Table 2-2 summarizes SUSD emissions for each turbine. Turbine operation during SUSD events will be counted toward the annual limit on operating hours; the net impact of SUSD operation on annual emissions depends on the difference between emission rates for SUSD and emission rates for normal operations. The table therefore presents the net impact of SUSD operations on potential annual emissions. A more detailed breakdown of SUSD data for each turbine is provided in Appendix B.

Emissions of SO_2 and PM during SUSD operation are at or below their respective emission rates during normal operation; there is no increase in emissions of these two pollutants as a result of SUSD operation.

Table 2-2: Startup/Shutdown Emissions (per turbine)

Startup & Shutdown Emissions – Summary		
Pollutant	**PTE Increase – GE-7FA (tpy)**	**PTE Increase - Siemens SGT6-5000F (tpy)**
NOx	17.1	5.2
CO	64.6	131.0
VOC	6.1	6.2

Total Number of Starts Per Year	250 for GE-7FA; 200 for SGT6-5000F
Number of Oil Starts Per Year	50 for GE-7FA; 30 for SGT6-5000F
Startup/Shutdown Hours Per Year	288 for GE-7FA; 219 for SGT6-5000F

2.4 Criteria Pollutant Potential Annual Emissions

Table 2-3 summarizes the estimated potential annual criteria pollutant emissions from the project. The potential annual emissions estimates assume that natural gas firing occurs on average at the daytime annual temperature of 59°F. Since ULSD firing is most likely to occur during the winter when natural gas demand and prices are at their highest, the potential annual emissions assume ULSD firing at the low ambient temperature of 3°F. The annual potential emissions also include the net increase from SUSD emissions (for two turbines) as described in Section 2.3.

Table 2-3: Potential Facility-Wide Criteria Pollutant Annual Emissions (tpy)

	Potential Emissions for GE-7FA			Potential Emissions for Siemens SGT6-5000F			Facility PTE
Pollutant	Baseload (tpy)	SUSD Net Increase	Total (tpy)	Baseload (tpy)	SUSD Net Increase	Total (tpy)	(tpy)
NO_x	101.5	34.2	135.7	98.3	10.4	108.7	135.7
CO	106.0	129.1	235.1	68.5	262.1	330.6	330.6
PM/PM_{10}	47.0	0	47.0	49.2	0	49.2	49.2
SO_2	5.72	0	5.72	6.18	0	6.2	5.72
VOC	12.5	12.2	24.8*	12.1	12.4	24.7*	24.8*
NH_3	39.0	0	39.0	41.7	0	41.7	41.7
H_2SO_4	1.0	0	1.0	0.8	0	0.8	1.0

* VOC total includes 0.2 tpy from the fuel oil storage tank.

2.5 Non-Criteria Pollutant Potential Emissions

The Project will emit federally listed non-criteria pollutants and hazardous air pollutants (HAPs) primarily as a result of incomplete combustion. The non-criteria pollutants include both federal HAPs as defined by EPA in Title III of the 1990 Clean Air Act Amendments and PSD regulated non-criteria pollutants. Emission rates have not been estimated for several PSD regulated pollutants including asbestos, fluorides, vinyl chloride, hydrogen sulfide, total reduced sulfur and reduced sulfur compounds, and radionuclides. None of these PSD pollutants are expected to be emitted from the Project.

The calculated non-criteria and HAP emissions for the facility are provided in Appendix B. HAP emissions for the combustion turbines were estimated using emission factors contained in EPA's *Compilation of Air Pollutant Emission factors, AP-42, Section 3.1*. Total potential combined HAP emissions are 5.7 tpy from the GE 7FA turbines and 6.3 tpy from the Siemens SGT6-5000F turbines. Therefore, the project will be a minor source of HAP emissions.

3. REGULATORY APPLICABILITY & COMPLIANCE ANALYSIS

This section presents a review of the federal and state air quality regulations that are applicable to operations of the proposed project.

3.1 Federal Clean Air Act and Amendments

In 1970 Congress passed Public Law 91-064, comprehensive Amendments to the 1967 Air Quality Act. The 1970 Clean Air Act Amendments (1970 Amendments) included the authority to establish NAAQS and to designate areas as either in "attainment" with the NAAQS or in "non-attainment" with the NAAQS. Areas where there is not sufficient monitoring data to prove that the area has met the NAAQS, were designated as "unclassifiable." The EPA and CTDEP treat areas designated as "unclassifiable" as attainment areas for permitting purposes. The 1970 Amendments also required states to develop plans, called State Implementation Plans (SIPs), to attain and maintain the NAAQS for non-attainment areas.

In 1977 Congress passed Public Law 95-95, the 1977 Clean Air Act Amendments (1977 Amendments), which adjusted the attainment dates for areas in non-attainment, codified requirements for major sources in attainment areas (called the PSD program), and required EPA to establish the minimum New Source Performance Standards (NSPS) for major new sources standards and National Emission Standards for Hazardous Air Pollutant (NESHAP) emissions.

In 1990 Congress again amended the Clean Air Act through Public Law 101-549 (1990 Amendments). The 1990 Amendments required each state to classify the severity of each non-attainment area for ozone. A non-attainment area could be classified as "moderate," "serious," "severe" or "extreme." Different attainment schedules for each non-attainment classification were specified by the 1990 Amendments. The 1990 Amendments also established requirements for a federally enforceable operating permit program, modified the law to further regulate emissions of HAPs, and established new requirements for Acid Rain precursors (NO_x and SO_2). Each of these programs is discussed in more detail below.

3.1.1 Ambient Air Quality

The 1970 Amendments required the EPA to establish and periodically review the maximum concentrations of pollutants in the ambient air to protect the public health and welfare. The federally promulgated standards are presented in Section 6 (Table 6-1).

Many areas of the country did not achieve the ozone standard in the timeframes established in either the 1970 or 1977 Amendments. The 1990 Amendments called for another review and classification of the ambient air quality of all regions of the United

States. Areas of the country which had air quality equal to or better than these standards (i.e., ambient concentrations less than a standard) as of March 15, 1991 became designated as "attainment areas," while those areas where monitoring indicated air quality was worse than the standards became known as "non-attainment areas." The states were also required to propose a classification for each non-attainment area. The designation of an area has particular importance for a proposed project, as it determines the type of permit review to which an application will be subject.

New major sources or major modifications to existing major sources that are located in attainment areas are required to obtain a PSD permit prior to initiation of construction. Major new sources or major modifications to existing major sources located in areas designated as non-attainment (or that adversely impact such areas) must meet the more stringent non-attainment new source review (NNSR) requirements. Major new sources can be subject to both PSD and NNSR for NO_x since NO_x is both a criteria pollutant under PSD and is a precursor to the formation of ozone under NNSR.

The Project is located in an area designated as attainment or unclassified for all criteria pollutants with the exception of the 8-hour ozone[1] and annual $PM_{2.5}$ ambient air quality standards. Bridgeport is located in a region classified as "moderate non-attainment" for ozone. Ozone attainment is achieved through regulation of NO_x and VOC emissions. The major source threshold for NO_x and VOC emissions in the location of the proposed project is 25 tpy. Therefore, the project will be a major source of NO_x emissions and subject to Non-Attainment New Source Review.

In accordance with the implementation requirements of the $PM_{2.5}$ standard, Connecticut is required to submit revisions of their State Implementation Plan (SIP) no later than December 2007 to implement regulations to achieve attainment of the $PM_{2.5}$ standard. In the interim, the EPA has issued guidance that PM_{10} shall be used as a surrogate for meeting New Source Review (NSR) requirements. Since project potential emissions are below the PM_{10} major source threshold of 100 tpy, the project is not a major source subject to NNSR with respect to $PM_{10}/PM_{2.5}$ emissions.

3.1.2 Prevention of Significant Deterioration (PSD) Review

PSD permit review is a federal program for new major sources of regulated pollutants and for major modifications to existing major sources, mandated by the 1970 Clean Air Act and promulgated as regulations at 40 CFR 52.21. The federal PSD program

[1] The 1-hour ozone standard was revoked effective June 15, 2005 for all areas in Connecticut. Despite this change, the major source threshold of 25 tpy for NOx and VOC emissions, and the requirement for emissions offsets at a ratio of 1.3 to 1, remain in force for the area that had been designated as "severe non-attainment" based on the 1-hour standard.

is administered by CTDEP pursuant to RCSA Section 22a-174-3a under the Abatement of Air Pollution regulations.

Under Connecticut's PSD program, a new project is considered a major stationary source subject to PSD review if potential emissions of any criteria pollutant are greater than 100 tpy. Based upon the emissions presented in Tables 2-5 and 2-6, the proposed project will be a PSD major source for CO and NO_x emissions. Additionally, potential PM/PM_{10} emissions exceed their significant emission rate threshold as defined in RCSA Section 22a-174-3a, Table 3a(k)-1. Table 3-1 compares potential emissions from the project to the PSD thresholds for all PSD regulated pollutants.

Table 3-1: Potential Emissions vs. PSD Thresholds

Pollutant	Project Potential Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicable?
NOx	135.7	25	Yes
CO	330.6	100	Yes
PM	49.2	25	Yes
$PM_{10}/PM_{2.5}$	49.2	15	Yes
SO_2	5.72	40	No
VOC	24.8	25	No
Lead (Pb)	0.015	0.6	No
Mercury (Hg)	0.0013	0.1	No
Sulfuric Acid Mist (H_2SO_4)	1.0	7	No

Accordingly, the project will be subject to PSD permitting requirements for NO_x, CO, and PM/PM_{10} emissions. In addition to the information provided for a standard permit to construct, the CT DEP regulations require the following additional information for PSD subject pollutants:

- Application of BACT controls;
- An evaluation of the proposed project's impact on ambient air quality ;
- An evaluation of the project's impact on visibility, soils, and vegetation; and
- A construction schedule

A BACT analysis is provided in Section 4 of this report. The analysis of the project's impact on ambient air quality, visibility, soils, and vegetation will be contained within the air dispersion modeling analysis to be provided under separate cover.

3.1.3 New Source Performance Standards (NSPS)

As required under the Clean Air Act, EPA has promulgated standards of performance for new sources that define minimum control requirements, recordkeeping, and reporting for all new sources in specific source categories. The combustion turbines will be subject to Subpart GG of 40 CFR 60. The proposed combustion turbines will meet or exceed the requirements of NSPS Subpart GG.

NSPS Subpart GG places restrictions on emissions of NO_x and SO_2 from the turbines. The allowable NO_x emission concentration is limited to a nominal value of 75 parts per million dry volume at 15 percent O_2 (ppmvd). An upward correction to this 75 ppmvd limit is allowed for fuel bound nitrogen content and turbine thermal efficiencies greater than 25 percent. The turbines will be equipped with DLN combustors and SCR in order to limit NO_x emissions to no greater than 3.0 ppm[2], which is well below the nominal NSPS limit of 75 ppmvd.

Under NSPS Subpart GG, SO_2 is limited to 150 ppmvd corrected to 15 percent O_2, and fuel sulfur content is limited to less than 0.8 wt%. The Project will meet these criteria by using natural gas as the primary fuel with ULSD as backup fuel. The sulfur content of natural gas is expected to be no greater than 0.5 grains/100 scf (<0.01%). The ULSD will have a maximum fuel sulfur content of 15 ppmw, or 0.0015 wt%. Therefore, the fuel sulfur content for the project will be well below the NSPS requirements. The corresponding maximum flue gas SO_2 concentrations will also be well below the NSPS standards, with SO_2 emissions of about 1 ppmvd corrected to 15 percent O_2.

3.1.4 Applicability of National Emission Standards for Hazardous Air Pollutants

Realizing that numerous pollutants did not meet the specific criteria for development of a NAAQS, Congress included Section 112 in the 1970 Amendments to specifically address this problem. Section 112 provides the EPA with a vehicle for developing standards for potentially hazardous pollutants.

The regulations that have been developed to implement Section 112(b) are presented in 40 CFR Parts 61 and 63. Unlike the NSPS, emission limits or control requirements developed to implement Section 112 of the Act, as amended, are applicable to both new and existing sources. As noted in Section 2.3, the project will be a minor source of HAP emissions. The EPA had issued a Maximum Achievable

[2] All ppm values are ppmvd at 15% O_2.

Control Technology (MACT) standard for gas-fired combustion turbines that were major HAP sources or were located at a major HAP source. However, on August 18, 2004 the EPA stayed the effectiveness of the MACT standard for lean pre-mix and diffusion flame gas-fired turbines until such time that these two subcategories could be deleted from the MACT standard. Since the proposed project is a minor HAP source and will incorporate lean pre-mix turbines, there are currently no MACT standards applicable to the project.

3.1.5 Federal Acid Rain Program - 40 CFR 72 and 75

EPA promulgated regulations to implement Title IV of the 1990 Amendments at 40 CFR 72 and 75. As one feature of the Acid Rain Program, EPA established a program to reduce SO_2 emissions from power plants by allocating a limited number of marketable allowances primarily to existing power plants and by requiring all plants, including new plants, that were not allocated allowances to hold or obtain allowances equal to their actual annual SO_2 emissions. Allowances are available through the Chicago Board of Trade and other sources, and will be secured by the Project in the amount required.

According to 40 CFR 72, the Project will be designated as a Phase II Acid Rain "New Affected Unit" 90 days after commencement of commercial operation. The regulations allow a review period of 24 months for reviewing and issuing acid rain permits. In practice, Phase II Acid Rain applications are typically approved in considerably less time than the 24 months allowed in the regulations. BEII will file the required application for the acid rain permit for the Project.

Under 40 CFR 72, the project will be required to install a continuous emissions monitoring system (CEMS). CEMS requirements are specified in 40 CFR 75 for monitoring of SO_2, NO_x, and CO_2 emissions as well as opacity and volumetric flow of the flue gas. As an option, natural gas and oil-fired facilities may conduct fuel quality and fuel flow monitoring in place of SO_2 monitoring and flue gas flow monitoring (40 CFR 75). CEMS reports provide the basis for demonstrating compliance with permit requirements. The project will install CEMS designed to meet the requirements under 40 CFR 75 for NO_x and CO_2. For SO_2 emissions and flue gas monitoring, the project will comply with the alternative monitoring requirements contained in 40 CFR 75, Appendix D.

3.1.6 Accidental Release Prevention Program

Ammonia is required by the SCR systems proposed to control NO_x emissions. The Accidental Release Program promulgated under Section 112(r) of the 1990 Clean Air Act Amendments governs the storage and handling of chemicals identified as extremely hazardous substances. For the SCR system, the project will utilize either anhydrous ammonia or aqueous ammonia with a maximum concentration no greater than 31 percent. BEII is evaluating the storage, transportation, and cost issues associated with both anhydrous and aqueous ammonia of varying concentrations in making its decision on which type of ammonia to implement. If anhydrous ammonia or aqueous ammonia at or above 20% is selected, the maximum quantity of ammonia stored will most likely be greater than 10,000 pounds and consequently the Project will be subject to the requirements of the Accidental Release Program under 112(r). The Accidental Release Program requires preparation of a Risk Management Plan (RMP) to evaluate the potential for a catastrophic release of the stored ammonia and to implement mitigation measures to minimize potential impacts.

If aqueous ammonia less than 20 percent is selected, the Project will not be subject to the specific provisions of the program, as the program does not regulate aqueous ammonia less than 20 percent concentration.

Regardless of the type of ammonia selected, the Project will incorporate state-of-the-art collection and mitigation measures to minimize the impacts from the storage and handling of the ammonia.

3.2 Connecticut Regulations and Policies

In addition to the federal NSR, NSPS, and Title IV provisions, there are a number of CTDEP air quality requirements that apply to the proposed Project. The applicable requirements of the Connecticut regulations are summarized below.

3.2.1 Maximum Allowable Stack Concentration (MASC)

Section 22-174-29 of the CTDEP regulations limits emissions of state regulated hazardous air pollutants (HAP) as defined in Tables 29-1, 29-2, and 29-3 of this regulation. The regulation establishes a Maximum Allowable Stack Concentration (MASC) for each state regulated HAP. The project will comply with the CTDEP MASC requirements. The compliance demonstration will be contained in the air dispersion modeling analysis report to be provided under separate cover.

3.2.2 Particulate Matter and Visible Emissions

Section 22-174-18 limits particulate matter and visible emissions from stationary sources. Visible emissions are limited to a 6-minute block average of no greater than 20 percent or a one minute average of not more than 40 percent opacity. The Project will be fired with natural gas and ULSD and will also incorporate state-of-the-art combustion controls, which will minimize visible emissions from the Project. Visible emissions will not exceed 20 percent from the turbines.

Particulate matter emissions are limited to no greater than 0.10 pounds per million Btu (lb/MMBtu). As detailed in Appendix B, the particulate matter emissions from the turbines will not exceed 0.044 lbs/MMBtu under all operating loads and fuels.

3.2.3 SO_2 Emissions

Section 22-174-19a limits SO_2 emissions from "power plants". The regulation limits the sulfur content of all fuels to no greater than 0.3% by weight (wt%) or SO_2 emissions to no greater than 0.33 lbs/MMBtu. The project will fire natural gas as the primary fuel with ULSD as backup fuel. The ULSD will have a maximum sulfur content of 15 ppmw, which is equivalent to 0.0015 wt%. As detailed in Appendix B, the SO_2 emissions from the turbines will not exceed 0.0015 lbs/MMBtu under all operating loads and fuels.

The regulation also requires that subject sources retire one Acid Rain allowance for each ton of SO_2 emitted above the Acid Rain allowance requirements under 40 CFR 72.

3.2.4 NO_x Emission Limitations

Sections 22-174-22 and 22-174-22b govern NO_x emissions from the project. Section 22-174-22 limits NO_x emissions from the turbines to no greater than 0.15 lb/MMBtu during the non-ozone season (October 1^{st} through April 30^{th}). With the application of SCR, the turbines emissions during ULSD firing will not exceed 15 ppmvd at 15% $O_{2,}$, which is equivalent to 0.058 lb/MMBtu.

Section 22-174-22b implements the post-2002 NO_x Budget Trading Program in Connecticut. The NO_x Budget Trading Program requires that subject sources secure NO_x Budget Allowances for each ton of emissions during the ozone season (May 1^{st} through September 30^{th}) each year. The turbines are defined as New Units under the regulation since their operation will commence after May 1, 2001. As a New Unit, the station may request allowances from the state's new unit set aside account to cover emission during the first two years of operation. Following the first two years, the station will be allocated allowances from the general pool.

3.2.5 Title V Permit Program

BEII will be a Title V major stationary source as a result of its NO_x and CO emissions. As a new major source, the facility is required to submit a Title V Operating Permit Application within 12-months from the commencement of operation in accordance with Section 22-174-33 of the CTDEP regulations.

3.2.6 Emissions Offsets

BEII will be located in a non-attainment area for ozone and will be major source of NO_x emissions and is therefore subject to NNSR for NO_x. Section 22-174-3a of the CTDEP regulations implements the NNSR program in Connecticut. In accordance with these regulations, BEII must secure NO_x emissions offsets at a ratio of 1.3:1 to offset the project's potential NO_x emissions prior to the commencement of operation.

BEII will obtain certified NO_x emissions offsets prior the commencement of operation. The amount of offsets required will be based upon the final turbine selection for the project.

4. ANALYSIS OF ALTERNATIVES, INCLUDING CONTROL TECHNOLOGY

BEII is proposing to install two (2) F-Class combustion turbines in simple cycle configuration in Bridgeport, CT. In accordance with the provisions of the Regulations of Connecticut State Agencies (RCSA) Section 22a-174-3a, a Best Available Control Technology (BACT) analysis must be completed for each criteria pollutant with potential emissions in excess of 15 tons per year (tpy) per emissions unit. Additionally, a Lowest Achievable Emission Rate (LAER) analysis is required, because potential NO_x emissions exceed 25 tpy. Based upon the potential to emit from the proposed project as presented in Section 2 of this application, a BACT analysis is required for emissions of particulate matter ($PM_{10}/PM_{2.5}$), CO and NH_3 to satisfy CTDEP permitting requirements. Potential NO_x emissions exceed 25 tpy and therefore will require LAER controls. As required by RCSA Section 22a-174-3a(l)(3)(F), LAER must be at least as stringent as the BACT requirements for NO_x .

Under RCSA-22a-174-3a (k)(2), the application for a source subject to LAER must include an "Analysis of Alternatives" which addresses alternative sites, alternative sizes for the subject source, alternative production processes, and all available control techniques. Further, such analysis must demonstrate whether the benefits of the source "*significantly outweigh its adverse environmental impacts, including secondary and cumulative impacts, and social costs imposed as a result of the location, construction or modification*."

The "analysis of alternatives" is presented below in Section 4.1; available control techniques for each pollutant are addressed in following sub-sections. LAER analysis for NO_x emissions is presented in 4.2, while BACT analysis for CO, $PM_{10}/PM_{2.5}$, and NH_3 is in 4.3 Control alternatives for VOC emissions are also addressed, although a BACT analysis for VOC is not required. These analyses are based upon current control levels achieved by "F" class simple cycle combustion turbines. The analyses were conducted for all subject pollutants and both the GE 7FA and Siemens SGT6-5000F model combustion turbines. The analyses also address both natural gas and distillate oil firing in the combustion turbines.

All parts-per-million (ppm) concentrations, with the exception of VOCs listed in the following text represent ppm dry volume at 15% oxygen (O_2). The measurement method for VOC emissions from combustion sources, 40 CFR 60 Appendix A Method 25A, measures emissions without moisture removal. Therefore, the VOC concentrations listed are ppm wet volume at 15% O_2.

4.1 Analysis of Alternatives

The proposed site is exceptionally well-suited for the proposed peaking station. Important advantages include a local shortage of peaking power, access to natural gas on-site, proximity to the regional electrical transmission system through the adjacent Singer Substation being constructed as part of the electric transmission line improvements being made in Southwestern Connecticut, and existing (larger) generating facilities on adjacent sites. Fairfield County is recognized as an area with a chronic shortage of peak generating capacity, and the regional transmission system does not provide the transmission capacity to import sufficient power from outside the region to meet local demand. The proposed facility is located in an industrial area; the proposed use is consistent with current zoning and neighboring land uses. With adjacent electric generating and transmission facilities, the proposed peaking station will not alter the character of the neighborhood.

Since the proposed site is the only one under the ownership and control of the applicant, other sites were not evaluated. However, as the Connecticut Siting Council stated in its *Review of the Ten Year Forecast of Connecticut Electric Loads and Resources 2006-2015*, the "most critical and constrained transmission area in the state, as well as New England, is the 54 town region referred to as Southwest Connecticut. . . ." (page 19) Therefore, locating new generation assets in southwest Connecticut, and especially near new transmission facilities, like the Singer Substation, is the most efficient and effective way to address the critical need for additional peaking generation capacity in Southwest Connecticut. The proposed site is perfectly situated to address this important need.

The 350-MW capacity of the proposed peaking station will make a substantial contribution to meeting the local demand for peaking power, and represents the maximum capacity that can be accommodated on this site. The choice of two 175-MW F-Class turbines provides greater operating flexibility to meet peaking demand, compared to a single larger turbine, and provides greater fuel efficiency, compared to a larger number of smaller turbines. For example, the Siemens SGT6-5000F (simple cycle) achieves a nominal fuel efficiency of 37.7 %, compared to 34.2 % efficiency for the smaller (118 MW) SSC-3000F.

Dual-fuel simple-cycle turbines represent the optimal method of generating power to meet peak demand. The use of ULSD as a back-up fuel provides reliability during periods of high demand for natural gas. No alternative types of power generating facilities provide the necessary combination of rapid demand response, reliability, and fuel efficiency. Coal-fired boilers, nuclear generating facilities, hydropower and combined-cycle turbines require longer times for start-up and cannot respond rapidly to shifting demand. Wind and solar power are intermittent and are only available during favorable weather conditions.

Alternative control technologies are addressed below by pollutant in Sections 4.2 and 4.3.

The proposed peaking facility will provide important social benefits by helping to ensure an adequate supply of electrical power to Bridgeport and surrounding communities. Increased peaking capacity in Fairfield County has been identified by ISO-New England, the Connecticut Department of Public Utility Control, and the Connecticut Siting Council as a critical need. At the proposed site, the peaking station will have minimal impact on the neighboring community. The installation of SCR to control NO_x emissions and the acquisition of emissions offsets at 1.3 to one will minimize Project impacts on regional ozone levels. The dispersion modeling analysis will ensure that cumulative impacts on ambient air quality for CO, PM and SO_2 are acceptable.

4.2 Lowest Achievable Emission Rate (LAER) Analysis for Nitrogen Oxide

BEII will be a new major source of potential NO_x emissions in excess of 25 tpy. Therefore, the Project is subject to NNSR for NO_x including application of LAER controls. LAER is defined as "the most stringent emission limitation contained in the implementation plan of any state for such class or category of source unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or the most stringent emission limitation achieved in practice by such class or category of source."[3]

LAER is expressed as an emission rate and may be achieved from one or more of the following emissions reduction methods:

- Change in raw material(s);
- Process modification(s); and
- Installation of add-on pollution controls.

In determining LAER, the Project evaluated CTDEP's and EPA's recommended sources of information, specifically:

- State Implementation Plan (SIP) limits for the appropriate class or category of sources;
- Preconstruction and/or operating permits issued; and
- The Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC).

[3] EPA, Office of Air Quality Planning and Standards, "New Source Review Workshop Manual," October 1990, p. G.2; Section 171(3) of the Federal Clean Air Act.

In addition to the sources of information listed above, a review of EPA's *National Combustion Turbine Projects Spreadsheet*[4] (last updated 07/20/2004) was also conducted. Following is an analysis of each emissions limiting option and applicable NO_x emission limits for other "F" class simple-cycle CTG facilities.

4.2.1 Evaluation of Emissions Limiting Techniques

NO_x is formed during the combustion of fuel in the turbine. The formation of NO_x from combustion is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric nitrogen is oxidized at high temperatures to yield NO, NO_2, and other oxides of nitrogen. Fuel-related NO_x is formed from the oxidization of chemically bound nitrogen in the fuel.

Reductions in NO_x emissions can be achieved using combustion controls or add-on controls or a combination of these control techniques. Available combustion controls for CTGs include water or steam injection and DLN combustors. The application of add-on controls for simple-cycle CTGs is limited. Selective catalytic reduction (SCR) is a commonly used add-on control technology for combustion turbines operating in combined-cycle mode. Combined-cycle turbines allow for installation of the SCR at its ideal operating temperature within a heat recovery steam generator (HRSG). Simple-cycle turbines do not include a HRSG and consequently exhaust temperatures are significantly higher. Additionally, "F" class combustion turbines have higher exhaust rates than smaller, less efficient, combustion turbines, which further complicates the application of SCR. As a result of these high exhaust temperatures, there has been very limited application of SCR on "F" Class simple cycle combustion turbines.

4.2.1.1 Change in Raw Materials

Limiting emissions through a change in raw materials is typically considered for industrial processes that use chemicals where substitution with a lower emitting chemical may be feasible. In this case, the "raw material" is a fuel to be combusted for the generation of electricity. The lowest emitting fuel for combustion processes is natural gas. Natural gas contains virtually no fuel bound nitrogen thereby eliminating this portion of NO_x from the combustion process. CTG manufacturers have also made significant technological improvements in DLN combustor design using a lean pre-mix fuel injection system to minimize thermal NO_x formation.

The Project will fire natural gas as the primary fuel resulting in the lowest NO_x emissions from the CTG. In addition to natural gas, BEII is proposing limited firing of distillate oil as backup fuel for the project. Distillate fuel firing is required as

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[4] http://www.epa.gov/ttn/catc/dir1/natlturb.xls

backup due to the constrained natural gas supply in New England and the critical power supply needs of Southwest Connecticut. Distillate oil firing will be limited to no greater than 500 hours per rolling 12-month period for each combustion turbine. Additionally, ultra-low sulfur diesel (ULSD) distillate oil will be used by the project. ULSD has been shown to contain lower amounts of fuel-bound nitrogen than standard diesel fuel and may help to lower NO_x emissions as compared to other distillate oil simple cycle combustion turbines.

4.2.1.2 Process Modifications

Process modifications are typically considered for industrial processes that use chemicals where a change in the process methods or conditions may result in lower emissions. In this case, the "process" is a combustion turbine firing natural gas. The Project will use either GE 7FA or Siemens SGT6-5000F combustion turbines equipped with lean pre-mix DLN combustors, which is the lowest NO_x emitting combustion technology for "F" class combustion turbines that is commercially available

The formation of both thermal and fuel NO_x depend upon combustion conditions. In a conventional combustor, the fuel and air are introduced directly into the combustion zone with fuel-air mixing and combustion taking place simultaneously. This approach does not optimize fuel-air mixing and results in fuel-rich pockets that produce areas of high temperatures causing increased thermal NO_x emissions.

In a DLN combustor, lean combustion techniques are utilized to reduce peak temperatures in the combustor and thereby minimize NO_x formation. In a lean premixed combustor design, the air and fuel are premixed at very lean air-to-fuel ratios prior to introduction in the combustion zone. The premixing of the air and fuel results in a homogeneous mixture that minimizes local fuel-rich zones. In addition, the excess air in the lean mixture acts as a heat sink that further minimizes peak combustion temperatures and thermal NO_x formation.

The combustion turbines will also incorporate advanced combustion control systems to monitor combustor operation and ensure efficient combustion. The combination of lean pre-mix DLN combustors with advanced combustion controls will limit NO_x emissions at the proposed operating loads. The Project has, therefore, selected the lowest NO_x emitting combustion turbines available.

4.2.1.3 Add-On Controls

Add-on controls can be classified as either front-end or back-end controls. Add-on controls for combustion turbines have historically been back-end applications. A front-end control currently being researched for combustion turbines is catalytic combustion. Catalytic combustion uses an oxidation catalyst within the combustor to oxidize the fuel at a lower temperature and consequently lower NO_x emissions. At this time, catalytic combustion is available for very small turbines (<3MW) but not for the "F" Class machines proposed for the project. At this time there are no commercially available front-end controls available for large combustion turbines and therefore, front-end controls were eliminated as a LAER control option.

Back-end controls remove NO_x from the exhaust gas stream once NO_x has been formed. The most efficient and widely used NO_x control technology for combustion turbines is SCR. SCR technology uses ammonia (NH_3) to reduce NO_x to N_2 and H_2O in the presence of a catalyst. The reactions that occur in an SCR system are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O, \text{ and}$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

An SCR system is composed of an ammonia storage tank, ammonia forwarding pumps and controls, an injection grid (a system of nozzles that spray ammonia into the exhaust gas ductwork), a reactor that contains the catalyst, and instrumentation and controls. The injection grid disperses NH_3 in the flue gas upstream of the catalyst, where NH_3 and NO_x are reduced to nitrogen (N_2) and water (H_2O).

To maximize NO_x reduction, ammonia is generally injected into the SCR in excess of stoichiometric amounts. This results in some unreacted ammonia that passes through the SCR reactor and is exhausted to the atmosphere. This ammonia that passes through the SCR unreacted is called the "ammonia slip."

SCR systems are common on combustion turbines operating in combined-cycle mode and have been applied to smaller simple cycle combustion turbines. There has been very limited application of SCR on larger "F" class combustion turbines. The primary technical concern for implementing an SCR system on an "F" class combustion turbine in simple-cycle mode is the very high exhaust gas temperature, which can exceed 1,200°F during certain operating conditions. The upper end operating temperature of SCR systems is typically 850°F, which is several hundred degrees below the maximum exhaust temperature of an "F" class combustion turbine.

The GE 7FA and Siemens SGT6-5000F combustion turbines proposed by the Project will have exhaust gas temperatures as high as 1,200°F and typically greater than 1,100°F as documented in Appendix B of this application. These temperatures greatly exceed the upper end operating temperature of SCR systems. Therefore, in order to operate an SCR system on the proposed combustion turbines, a cooling air system will be required to lower the exhaust temperature below the maximum operating temperature of the SCR.

A review of available sources of information, as described in Section 4.1, identified only two simple cycle combustion projects that incorporated SCR with a cooling air system. The first installation of SCR with a cooling air system was at the Puerto Rico Electric Power Authority (PREPA) Central Cambalache facility in Arecibo, Puerto Rico. The PREPA facility operates three ABB GT11N turbines firing No. 2 oil only (≤0.2 wt% S). An SCR system was installed on these turbines to reduce NO_x emissions from 42 ppm down to 10 ppm.

From July 1997 through September 2001, the SCR systems failed to operate as designed despite the efforts of PREPA, the combustion turbine provider (ABB Alstom), and the catalyst manufacturer (Englehard). The expected cause of the SCR system failure was catalyst poisoning due to high SO_2 emissions resulting in sulfuric acid mist (H_2SO_4) emissions as well as emissions of heavy metals. In September 2001, the EPA and PREPA agreed to remove the SCR systems and the facility's permit was revised to the uncontrolled NO_x emission level of 42 ppm.

The second known installation of an SCR with cooling air system is at the Riverside Generating Company facility in Frankfort, KY. The facility operates five Siemens 501F combustion turbines, which are equivalent to the Siemens SGT6-5000F turbines, that fire natural gas only. Two of the five combustion turbines are equipped with SCR systems. However, a review of the facility's air permit shows that the NO_x emission limit for all five combustion turbines is the same at 20 ppm. Further review of the permit indicates that the facility voluntarily elected to install SCR on two of the turbines so that operating hours could be increased without triggering the PSD threshold of 250 tpy for NO_x emissions.

A review of annual Acid Rain emissions data was conducted to determine the NO_x emission level achieved by the two turbines at Riverside Generating that are equipped with SCR. This review showed that the NO_x emission level for these two turbines was equivalent to the NO_x emission level achieved by the other three turbines without SCR. The lowest annual NO_x emission level achieved by the two turines with SCR since their initial operation in 2001 was 0.06 pounds per million BTU, or roughly 16 ppm. This data indicates that these two turbines have operated very little with operation of the SCRs.

In summary, there are no known successful applications of SCR on a large "F" class combustion turbine in simple cycle mode for an extended period of time. However, the installation of SCR at the Riverside Generating facility in Kentucky and discussions with SCR vendors indicates that the application of SCR to the project is technically feasible. The utilization of ULSD should mitigate the SCR catalyst poisoning concerns that occurred at the PREPA facility. A cooling air system will be necessary to prevent thermal degradation of the SCR catalyst such that the temperature at the catalyst face must not exceed 850°F based upon a maximum exhaust gas temperature of 1200°F.

4.1.2 Sources Consulted to Determine LAER

A review of the RBLC and other known preconstruction permits for large gas-fired simple cycle combustion turbine projects was conducted to evaluate permitted BACT and LAER NO_x emission rates since the beginning of 2002. Provided in Table 4-1 is a summary of known BACT and LAER NO_x emission rates for projects permitted since the beginning of 2000.

All of the limits identified in Table 2-1 are BACT limits with the exception of the Sithe West Medway project in Massachusetts, which was a LAER project for NO_x emissions. Based upon these projects, the lowest permitted NO_x emission limit for an "F" class simple cycle combustion turbine project identified is 9 ppm on a one-hour basis for natural gas and 42 ppm on a three-hour basis for oil.

Table 4-1: Recent NO_x Permit Limits for Large Simple Cycle Projects

Facility	Permit Date	Combustion Turbine	NO_x (ppm)		Controls
			Gas	Oil	
Faribault Energy Park - MN	07/2004	Mitsubishi 501F	25 (3-hr)	42 (3-hr)	DLNC / WI
Cass County Power – NE	06/2004	West. 501F	20	NA	DLNC
Currant Creek Power – UT	05/2004	GE 7FA	9 (18-hr)	NA	DLNC
Broad River Energy – SC	05/2003	GE 7FA	9 12 w/ P.A.	42	DLNC / WI
Chickahominy Power – VA	01/2003	Siemens 501F	15	NA	DLNC
White Oak Power – VA	08/2002	GE 7FA	9	NA	DLNC
Sithe West Medway – MA	04/2002	GE 7FA	9 (1-hr)	NA	DLNC
Rowan Generating – NC	01/2002	GE 7FA	9 (24-hr)	42 (24-hr)	DLNC / WI

Note: EPA's *National Combustion Turbine Projects Spreadsheet* incorrectly lists the following combined-cycle projects as simple-cycle: ExxonMobil – TX (06/13/03); BP Amoco Chemical – TX (03/24/03); OxyVinyls, LP – TX (12/20/02); Hartburg Power – TX (07/05/02); Connectiv Bethlehem North – PA (11/16/02); Mobil Oil – TX (03/14/00); and Lost Pines Power – TX (09/30/99).

4.1.3 LAER Proposal

Based upon this review of available control technologies and previously permitted "F" class simple-cycle combustion turbine projects, BEII proposes to incorporate the following NO_x emission controls to achieve LAER for the project:

1. Utilize natural gas as the primary fuel restricted to ≤2,500 hr/yr/turbine (5,000 hr/yr both turbines combined); and

2. Restricted use of ULSD as backup fuel restricted to ≤500 hr/yr/turbine (1,000 hr/yr both turbines combined); and

3. DLN Combustors to limit NO_x emissions during both natural gas and ULSD firing; and

4. Water Injection to limit NO_x emissions during ULSD firing; and

5. Post-combustion control with a dilution air system and Selective Catalytic Reduction.

The application of these controls will achieve the following NO_x emission levels:

- 3.0 ppm on a 3-hr block average basis during natural gas firing; and

- 15 ppm on a 3-hr block average basis during ULSD firing.

The proposed controls and emission limits represent the most stringent NO_x controls on an "F" class simple cycle combustion turbine project in the United States. By definition, these proposed controls meet LAER requirements.

4.3 BACT Analysis

Connecticut's air regulations require the application of BACT for each regulated pollutant emitted from a project that exceeds the thresholds listed in Table 3-1, or for any regulated pollutant emitted by an individual emissions unit at greater than 15 tpy. The pollutants subject to Connecticut's BACT requirements are SO_2, CO, $PM_{10}/PM_{2.5}$, and NH_3.

BACT is defined in Connecticut's regulations as "an emissions limitation...based on the maximum degree of reduction for each applicable pollutant emitted...which the commissioner, on a case-by-case basis, determines is achievable. The commissioner shall take into account energy, economic, and environmental impacts, including secondary and cumulative impacts, and other costs".

The CT DEP requires a "top-down" approach to BACT analysis. The process begins with the identification of control technology alternatives for each pollutant. Technically infeasible technologies are eliminated and the remaining technologies are ranked by control efficiency. These technologies are evaluated based on economic, energy and environmental impacts. If an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected.

A BACT analysis is presented below for emissions of SO_2, CO, and $PM_{10}/PM_{2.5}$ from the Project. Because the more stringent LAER is applied to NO_x, the LAER analysis for NO_x is presumed to meet BACT requirements and therefore no additional BACT information is provided for NO_2. The same sources of information reviewed to determine LAER for NO_x emissions as described in Section 4.1 were reviewed to determine BACT for each subject pollutant.

4.3.1 Sulfur Dioxide (SO_2)

SO_2 is emitted from combustion turbines as a result of the oxidation of the sulfur in the fuel. Therefore, utilization of low sulfur fuels is the simplest and best means for limiting SO_2 emissions. Natural gas generally has the lowest sulfur content of all fossil fuels. Based on the maximum expected sulfur content in the natural gas supply (0.5 grain/100 scf), SO_2 emissions during gas firing will not exceed 0.0012 lb/MMBtu. The facility will use ULSD oil with a maximum sulfur content of no greater than 15 ppm (≤0.0015 wt%), which is equivalent to an SO_2 emission rate of 0.0015 lb/MMBtu. These are the lowest fuel sulfur limits identified for each fuel type during review of the sources consulted to determine BACT. Add-on pollution controls (such as scrubber systems) for SO_2 reduction have never been applied to a combustion turbine. The extremely high gas flow rate and low fuel sulfur produce a very dilute exhaust gas stream, which makes add-on control both technically and economically unfeasible.

Therefore, the use of natural gas as the primary fuel and limited firing of ULSD represents BACT for control of SO_2 emissions from the project.

4.3.2 Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

CO and VOC are emitted from combustion turbines as a result of incomplete oxidation of the fuel. Similar to NO_x emissions, these pollutants are minimized by the use of proper combustor design and good combustion practices. The BACT analysis for CO includes discussion of VOC, since the same control methods are appropriate for both.

In reviewing the BACT alternatives for the Project, two CO control techniques have been considered: efficient combustion resulting from proper design and operation of the turbine; and catalytic oxidation add-on control technology.

The most stringent CO control technology is a catalytic oxidation system. This system is a passive reactor that consists of a honeycomb grid of metal panels coated with a platinum catalyst. The catalyst grid is placed in the engine exhaust where the optimum reaction temperature can be maintained (>500°F). In these systems, typically 80-90 percent of the CO is oxidized to CO_2. In addition, the catalyst may provide some reduction in VOC emissions dependent upon the specific organic species in the turbine exhaust.

A review of available sources of information did not identify any “F” class simple cycle combustion turbine projects that were required to install an oxidation catalyst. There are potentially significant environmental impacts associated with the use of a catalytic oxidation system because of the oxidation of SO_2 to SO_3. Catalyst vendors predict that from 20 to 80 percent of the SO_2 in the turbine exhaust will be further oxidized to SO_3 by the catalyst, depending upon its actual operating temperature. The additional SO_3 will most likely react with water to form H_2SO_4 or with the ammonia slip to form ammonium salts. Each of these two pollutants will most certainly be emitted in the form of $PM_{10}/PM_{2.5}$. Bridgeport is located in an area designated as non-attainment for the current $PM_{2.5}$ national ambient air quality standard (NAAQS). EPA has recently proposed to lower the $PM_{2.5}$ NAAQS in half in order to provide greater protection of public health. Therefore, an oxidation catalyst would increase emissions of $PM_{2.5}$ in an area that is currently designated as non-attainment and may have difficulty achieving attainment of the newly proposed standard.

The project is located in an area that is in attainment with the CO NAAQS. Based upon preliminary air dispersion modeling data, the maximum predicted ambient air concentrations of CO from the project will be well below the PSD Significant Impact Levels (SILs) based upon the proposed BACT emission rates. This result is expected to be formalized when the final air dispersion modeling analysis is submitted under separate cover. Therefore, the CO emissions from the project, without add-on controls, are presumed not to cause or contribute to a PSD increment or NAAQS violation and to have essentially no impact on the existing air quality for CO. Assuming the additional SO_3 was completely converted to $H_2SO_4/PM_{2.5}$, there would be an increase in potential $H_2SO_4/PM_{2.5}$ emissions of more than 10 tpy. Therefore, installation of an oxidation catalyst would reduce emissions of one pollutant that is having no impact on the existing air quality and increase emissions of a secondary pollutant in an area that is designated as non-attainment for that secondary pollutant.

The performance penalty associated with a CO catalyst system represents a further dis-benefit of add-on control. The estimated performance loss (0.12 percent) has the effect of increasing emissions of all other pollutants, per kW of electrical power delivered to the grid. From a greenhouse gas perspective, it would require an increase of 7 lb of CO_2 emissions, for every lb of CO controlled, to make up for this performance loss.

A cost to control analysis was also conducted for the application of an oxidation catalyst on the turbines. This analysis, as presented in Appendix B, shows that the CO cost to control for the turbines is between $7,300/ton and $7,800/ton. These costs are based upon a baseload control level of 1 ppm during gas firing. This cost to control is excessive for the control of CO emissions.

Taking into account that no known large combustion turbine simple-cycle project has installed an oxidization catalyst, the catalyst will result in a net negative impact to the environment, and the excessive cost to control, an oxidation catalyst was determined to not be BACT for the project.

The next level of control for CO/VOC emissions is efficient combustion control. As discussed previously, the combustion turbines proposed for the Project incorporate state of-the-art DLN combustors and advanced combustion controls to maximize combustion efficiency and minimize CO/VOC emissions. The proposed BACT CO/VOC emission levels (at 15% O_2) for the project are as follows:

<u>GE 7FA Turbines</u>

- CO ≤8.0 ppm 3-hr block average, natural gas firing;
- CO ≤16.0 ppm 3-hr block average, ULSD firing;

- VOC ≤1.1 ppm, natural gas firing; and
- VOC ≤3.9 ppm, ULSD firing.

Siemens SGT6-5000F Turbines

- CO ≤4.5 ppm 3-hr block average, natural gas firing;
- CO ≤12.0 ppm 3-hr block average, ULSD firing;
- VOC ≤0.9 ppm, natural gas firing;
- VOC ≤4.6 ppm, ULSD firing.

4.3.3 Particulate Matter ($PM_{10}/PM_{2.5}$)

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel. Particulate emissions will be minimized by use of natural gas as the primary fuel with limited firing of ULSD, which contains virtually no ash. There are no applications of particulate matter add-on controls on combustion turbines due to the already low emissions from combustion turbines and the large exhaust volume. The proposed $PM_{10}/PM_{2.5}$ emissions from both the GE 7FA and Siemens SGT6-5000F combustion turbines, based upon vendor guarantees, are as follows:

GE 7FA Turbines

- ≤0.011 lb/MMBtu, natural gas firing;
- ≤0.023 lb/MMBtu, ULSD firing.

Siemens SGT6-5000F Turbines

- ≤0.0083 lb/MMBtu, natural gas firing;
- ≤0.035 lb/MMBtu, ULSD firing.

4.3.4 Ammonia (NH_3)

Ammonia is used in the SCR systems for the reduction of NO_x emissions as described in Section 4.1.1.3. Some of the injected NH_3 will pass through the SCR catalyst unreacted and be emitted to the atmosphere. This unreacted NH_3 is referred to as the SCR's "ammonia slip". The ammonia slip is limited by proper SCR design and NH_3 injection control systems. BEII proposes to limit the ammonia slip to 6 ppm based upon vendor specification for the system.

4.4 Proposed Project Emissions Summary

Tables 4-2 and 4-3 summarize the proposed LAER/BACT emission rates and the annual emissions for criteria pollutants from the GE 7FA and Siemens SGT6-5000F combustion turbines, respectively. The resulting annual emissions from these BACT emission rates were presented in Tables 2-5 and 2-6.

Table 4-2: GE 7FA LAER and BACT Emission Rates

Pollutant	Fuel	ppm(1)	(lb/MMBtu)(1)	lb/hr(2)
NO_x	Nat. Gas	3.0 (3-hr)	0.011	22.0
	ULSD	15.0 (3-hr)	0.058	123.0
CO	Nat. Gas	8.0 (3-hr)	0.018	36.0
	ULSD	16.0 (3-hr)	0.038	80.0
VOC	Nat. Gas	1.1 (1-hr)	0.0017	3.4
	ULSD	3.9 (1-hr)	0.0059	12.5
$PM/PM_{10}/PM_{2.5}$	Nat. Gas	NA	0.011	15.0
	ULSD	NA	0.023	34.0
SO_2	Nat. Gas	NA	0.0012	2.23
	ULSD	NA	0.0015	3.24

Notes:

(1) For all operating loads above 50% of full load.

(2) Maximum hourly emission rate per turbine based on an ambient temperature of 3°F.

Table 4-3: Siemens SGT6-5000F LAER and BACT Emission Rates

Pollutant	Fuel	ppm(1)	(lb/MMBtu)	lb/hr(2)
NO_X	Nat. Gas	3.0 (3-hr)	0.011	25.0
	ULSD	15.0 (3-hr)	0.058	125.0
CO	Nat. Gas	4.5 (3-hr)	0.010	23.0
	ULSD	12.0 (3-hr)	0.0285	61.0
VOC	Nat. Gas	0.9 (1-hr)	0.0014	3.2
	ULSD	4.6 (1-hr)	0.0070	15.0
$PM/PM_{10}/PM_{2.5}$	Nat. Gas	NA	0.0083	12.0
	ULSD	NA	0.035	60.0
SO_2	Nat. Gas	NA	0.0012	2.6
	ULSD	NA	0.0015	3.3

Notes:

(1) For all operating loads above 75% of full load.

(2) Maximum hourly emission rate per turbine based on an ambient temperature of 3°F.

Appendix A

CTDEP Application Forms

Application Forms

Public Notice in this Appendix

DEP-AIR-APP-200 in this Appendix

Attachment A: Executive Summary in this Appendix

Attachment B: Applicant Background Information in this Appendix

Attachment C: Site Plan provided in Appendix C

Attachment D: USGS Map and Latitude/Longitude Form Map provided in report as Figure 1-1; Lat/Lon Form included in this Appendix

Attachment E: Supplemental Application Forms

- ***Stack Parameters (AIR-APP-211) -*** in this Appendix
- ***Unit Emissions-(AIR-APP-212) –*** in this Appendix. Details in Appendix B
- ***Air Pollution Control Equipment-(AIR-APP-210)-***in this Appendix
- ***Fuel Burning Equipment (AIR-APP-202) -*** in this Appendix
- ***Volatile Liquid Storage (APP-204) -*** in this Appendix

Attachment F: Major Premise Pollutant Summary not applicable (new facility)

Attachment G: BACT Determination information provided in Section 4 of report

Attachment H: Emergency Episode Standby Plan in this Appendix

Attachment I: Operation and Maintenance Plan in this Appendix

Attachment J: Ambient Air Quality Analysis provided under separate cover

Attachment K: Applicant Compliance Information in this Appendix

Attachment L: Conformance Certification in this Appendix

EarthTech
A tyco International Ltd. Company

300 Baker Avenue
Concord, MA
01742

P 978.371.4000
F 978.371.2468
www.earthtech.com

February 26, 2007

Engineering & Enforcement Division
Bureau of Air Management
Department of Environmental Protection
79 Elm Street
Hartford, CT 06106-5127

Subject: Bridgeport Peaking Station
New Source Review Permit Application by Bridgeport Energy II, LLC

Dear Sirs:

A permit application for Bridgeport Peaking Station was submitted by Bridgeport Energy II, LLC to the Department's Central Permit Processing Unit on February 16, 2007.

Enclosed are the Certification of Notice Form pertaining to this application and a notarized statement from the Connecticut Post, documenting the publication of the Public Notice on February 20, 2007. A copy of the public notice was also delivered to Mr. John Michael Fabrizi, Mayor of Bridgeport, on February 20.

Please contact me if you have any questions or need any additional information concerning these forms.

Sincerely yours,
Earth Tech, Inc.

Richard J. Londergan
Senior Program Director

Cc: Blake Wheatley, LS Power Development, LLC
Andrew Degon, LS Power Development, LLC
Robert Haley, LS Power Development, LLC

STATE OF CONNECTICUT
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP USE ONLY
Division
Application No.

Certification of Notice Form - Notice of Application

I , **Richard Londergan** , certify that
(Name of Applicant)

the attached notice is a true copy of the notice that appeared in **The Connecticut Post**
(Name of Newspaper)

on **02/20/2007** .

I also certify that I have provided a copy of the notice to the municipal official(s) listed below as required by CGS Section 22a-6g.

John Michael Fabrizi
(Name of Official)

Mayor
(Title of Official)

Bridgeport, CT
(Address)

(Name of Official)

(Title of Official)

(Address)

Signature of Applicant

02/26/2007
Date

Richard J. Londergan
Name of Applicant (print or type)

Sr Program Director
Title (if applicable)

CONNECTICUT POST

Certificate of Publication

Classified Advertising Department
410 State Street, Bridgeport, CT 06604
203-330-6213, 800-423-8058, ext. 6213
Fax 203-384-1158

This is to certify that the advertisement of NOTICE OF PERMIT APPLICATION - BPT. ENERGY II

was published in the Connecticut Post newspaper on 2/20/07
(Month, Day, Year)

Signed A. Score
(Advertising Representative)

Ad Number 110109

Account Telephone Number 978 371-4258

Purchase Order Number

Subscribed and sworn to before me

This 22nd day of February 2007

Donna L. Robinson
Notary Public

Sate Commission Expires 09/30/2007

OFFICIAL SEAL
Donna L. Robinson
Notary Public
Connecticut
My Commission Expires Sept. 30, 2007

Notice of Permit Application

Bridgeport

Notice is hereby given that Bridgeport Energy II, LLC (the "applicant") of Atlantic Street & Russell Street, Bridgeport, CT has submitted to the Department of Environmental Protection an application under Connecticut General Statutes Section 22a-174 for a permit to construct, install, enlarge or establish an air contaminant source or to operate a source regulated under the federal Clean Air Act.

Specifically, the applicant proposes to build and operate a new 350 MW nominal simple cycle combustion turbine generating facility. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. The project will be called the Bridgeport Peaking Station (BPS). The new facility will be located at Atlantic Street and Russell Street, south of the existing Bridgeport Energy facility on a parcel of land adjacent to the western boundary of the existing Bridgeport Harbor Station property. BPS will be owned and operated separately from the existing Bridgeport Energy generating station. The proposed activity will potentially affect air resources.

Interested persons may obtain copies of the application from Richard Londergan, Earth Tech, Inc., 300 Baker Avenue, Suite 290, Concord, MA 01742, (978) 371-4258.

The application is available for inspection at the Department of Environmental Protection, Bureau of Air Management, Permitting Section, 79 Elm Street, 5th floor, Hartford, CT 06106-5127, 860-424-4152, from 8:30 to 4:30 Monday Through Friday.

Notice of Permit Application

Bridgeport

Notice is hereby given that Bridgeport Energy II, LLC (the "applicant") of Atlantic Street & Russell Street, Bridgeport, CT has submitted to the Department of Environmental Protection an application under Connecticut General Statutes Section 22a-174 for a permit to construct, install, enlarge or establish an air contaminant source or to operate a source regulated under the federal Clean Air Act.

Specifically, the applicant proposes to build and operate a new 350 MW nominal simple cycle combustion turbine generating facility. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. The project will be called the Bridgeport Peaking Station (BPS). The new facility will be located at Atlantic Street and Russell Street, south of the existing Bridgeport Energy facility on a parcel of land adjacent to the western boundary of the existing Bridgeport Harbor Station property. BPS will be owned and operated separately from the existing Bridgeport Energy generating station. The proposed activity will potentially affect air resources.

Interested persons may obtain copies of the application from Richard Londergan, Earth Tech, Inc., 300 Baker Avenue, Suite 290, Concord, MA 01742, (978) 371-4258.

The application is available for inspection at the Department of Environmental Protection, Bureau of Air Management, Permitting Section, 79 Elm Street, 5th floor, Hartford, CT 06106-5127, 860-424-4152, from 8:30 to 4:30 Monday Through Friday.

CONNECTICUT POST PROOF

Customer: EARTH TECH Contact: RICHARD LONDERGAN Phone: 9783714258

Address: 300 BAKER AVENUE
CONCORD MA 01742

Ad Number: 1101109 PUB: PO

Insert Dates: 02/20/2007 02/20/2007

Price: 241.80

Section: CL Class: 11031; PUBLIC NOTICE - 2 COLUMN Size: 2 x 40.00

Printed By: R209 Date: 02/22/2007

Salesperson No: R209

Signature of Approval: ____________________ Date:________________

Permit Application for New Source Review Stationary Sources of Air Pollution

Please complete this form in accordance with CGS Section 22a-174, RCSA Sections 22a-174-1 and 3, and the instructions (DEP-AIR-INST-200). Print or type unless otherwise noted.

Part I: Application and Source Type

Please read the instructions (DEP-AIR-INST-200) in order to properly complete the table below. Please reproduce this page if additional space is necessary. You may apply for more than one permit on one application if the sources originate from the same premise. *Each* unit or process line requires a separate permit.

Unit No.	Source Type	App. Type (N, R, M)	If renewal or modification, indicate existing permit/reg. no.	DEP Use Only		
				Application No.	Permit No.	EPE No.
U1	fuel burn	N				
U2	fuel burn	N				

Part II: Fee Information

Please note: effective August 21, 2003 an initial fee of $750.00 is to be submitted for *each* permit that you are applying for. *Each* unit or process line requires a separate permit. For municipalities, the 50% discount applies. The application will not be processed without the initial fee. If a permit is required, an invoice will be sent for the permit fee. See RCSA Section 22a-174-26 for information regarding the amount of the permit fee.

Part III: Applicant Information

1. Fill in the name of the applicant(s) as indicated on the *Permit Application Transmittal Form* (DEP-APP-001).

   Applicant: **Bridgeport Energy II, LLC**

   Applicant's interest in property at which the proposed activity is to be located:

   ☒ site owner ☐ option holder ☐ lessee

   ☐ easement holder ☐ operator ☐ other (specify)

   ☐ Enter a check mark if there are co-applicants. If so, label and attach additional sheet(s) with the required information as supplied above.

2. List primary contact for departmental correspondence and inquiries, during processing of application, if different than the applicant.

   Name: **Earth Tech, Inc.**

   Mailing Address: **300 Baker Avenue, Suite 290**

   City/Town: **Concord** State: **MA** Zip Code: **01742-**

   Business Phone: **978-371-4258** ext. Fax: **978-371-2468**

   Contact Person: **Richard Londergan** Title: **Senior Program Director**

3. List primary contact for departmental correspondence and inquiries, after permit is issued, if different than the applicant.

   Name:

   Mailing Address:

   City/Town: State: Zip Code: -

   Business Phone: - - ext. Fax: - -

   Contact Person: Title:

4. List attorney or other representative, if applicable.

   Firm Name: **Murtha Cullina LLP**

   Mailing Address: **City Place I, 185 Asylum Street**

   City/Town: **Hartford** State: **CT** Zip Code: **06103-3469**

   Business Phone: **860**-240-**6034** ext. Fax: **860-240-5834**

   Attorney Name: **Mark Sussman** Title: **Attorney**

Part III: Applicant Information (continued)

5. List equipment operator, if different than the applicant.

   Name:

   Mailing Address:

   City/Town: State: Zip Code: -

   Business Phone: - - ext. Fax: - -

   Contact Person: Title:

6. List equipment owner, if different than the applicant.

   Name:

   Mailing Address:

   City/Town: State: Zip Code: -

   Business Phone: - - ext. Fax: - -

   Contact Person: Title:

7. List any engineer(s) or other consultant(s) employed or retained to assist in preparing the application or in designing or constructing the activity. Please enter a check mark if additional sheets are necessary, and label and attach them to this sheet. ☐

   Name: **Earth Tech, Inc.**

   Mailing Address: **300 Baker Avenue, Suite 290**

   City/Town: **Concord** State: **MA** Zip Code: **01742-**

   Business Phone: **978-371-4258** ext. Fax: **978-371-2468**

   Contact Person: **Richard Londergan** Title: **Senior Program Director**

   Service Provided: **Environmental Consultant**

Part IV: Premise Information

1. Name of facility, if applicable: **Bridgeport Peaking Station**

   Street Address or Description of Location: **Atlantic Avenue at Russell Street**

   City/Town: **Bridgeport** State: **CT** Zip Code: **06604-**

   Latitude and Longitude of the approximate "center of the site" in *degrees, minutes, and seconds*:

   Latitude: **41 deg 10 min 05.16 s N** Longitude: **73 deg 11 min 01.68 s W**

   Method of determination (check one): ☐ GPS ☐ USGS MAP ☒ other

   If a USGS Map was used, provide the quadrangle name:

2. Is or will the premise be located on federally recognized Indian lands? ☐ Yes ☒ No

Part IV: Premise Information (continued)

3. Identify the air quality attainment status of the area in which the premise is or will be located. (Check all that apply. See instructions for the air quality attainment status of Connecticut municipalities).

Non-Attainment for Ozone Standard: ☒ Severe ☐ Serious

Carbon Monoxide:

☐ Moderate Non-Attainment ☐ Unclassified Non-Attainment ☐ Unclassified Attainment

Non-Attainment for PM_{10}: ☐

4. SIC Codes:

Primary **4911** Secondary Other Other

Part V: Supporting Documents

Be sure to read the instructions (DEP-AIR-INST-200) to determine whether the attachments listed are applicable to your specific activity. Please enter a check mark by the attachments as verification that **all applicable** attachments have been submitted with this Permit Application Form. When submitting any supporting documents, please label the documents as indicated in this Part (e.g., Attachment A, etc.) and be sure to include the applicant's name as indicated on the *Permit Application Transmittal Form*.

☒ Attachment A: *Executive Summary* (DEP-AIR-APP-222)

☒ Attachment B: *Applicant Background Information* (DEP-APP-008)

☒ Attachment C: Site Plan

☒ Attachment D: An 82" X 11" copy of the relevant portion, or a full size original, of a USGS Quadrangle Map indicating the exact location of the facility or site and, if applicable, *Latitude and Longitude* (DEP-APP-003)

☒ Attachment E: Supplemental Application Forms

In the space provided by each supplemental application form, indicate the quantity of each form attached as part of this application. For each supplemental application form submitted, please provide a process flow diagram indicating all units, air pollution control equipment and stacks, as applicable. See sample diagram in instructions (DEP-AIR-INST-200).

☐ *Manufacturing or Processing Operations* (DEP-AIR-APP-201): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable.

☒ *Fuel Burning Equipment* (DEP-AIR-APP-202): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable.

☐ *Stationary Reciprocating Internal Combustion Engine - Compliance Assurance Form*
(DEP-AIR-COMP-001), if applicable.

☐ *Incinerators* (DEP-AIR-APP-203): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable. Also, attach documentation of waste heat contents and waste analysis.

Part V: Supporting Documents (continued)

Attachment E: Supplemental Application Forms (continued)

- ☒ *Volatile Liquid Storage* (DEP-AIR-APP-204): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable. Also, attach a MSDS for each product stored.
- ☐ *Surface Coating or Printing Operations* (DEP-AIR-APP-205): Attach a process flow diagram indicating all applicator identifications, air pollution control equipment, and stacks, as applicable. Also, attach a MSDS for each coating, ink, thinner, catalyst, cleanup solvent, or other compound to be used in this type of operation. Also, attach documentation to support transfer efficiency of spray applicators, if applicable.
- ☐ *Metal Plating and Surface Treatment Operations* (DEP-AIR-APP-206): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable. Also, attach a MSDS for each product stored in a tank.
- ☐ *Metal Cleaning Degreasers* (DEP-AIR-APP-207): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable. Also, attach a MSDS for each solvent used.
- ☐ *Concrete, Asphalt, Aggregate, Coal, Feed, Flour, & Grain* (DEP-AIR-APP-208): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable.
- ☐ *Site Remediation Equipment* (DEP-AIR-APP-209): Attach a process flow diagram indicating all units, air pollution control equipment, and stacks, as applicable. Also, submit documentation, such as pilot test data, which characterizes the site's degree of contamination.
- ☒ *Air Pollution Control Equipment* (DEP-AIR-APP-210), if applicable
- ☒ *Stack Parameters* (DEP-AIR-APP-211)
- ☒ *Unit Emissions* (DEP-AIR-APP-212): Attach all calculations by which emissions were determined.

☐ Attachment F: *Major Premise Pollutant Summary* (DEP-AIR-APP-213), if applicable

☒ Attachment G *BACT Determination Form* (DEP-AIR-APP-214), if applicable

☒ Attachment H: *Emergency Episode Standby Plan*, if applicable

☒ Attachment I: *Operation and Maintenance Plan*, if applicable

☒ Attachment J: *Ambient Air Quality Analysis*, if applicable

☒ Attachment K: *Applicant Compliance Information* (DEP-APP-002)

☒ Attachment L: *Conformance Certification Form* (DEP-AIR-APP-215)

Part VI: Application Certification

The applicant **and** the individual(s) responsible for actually preparing the application must sign this part. An application will be considered incomplete unless all required signatures are provided.

"I have personally examined and am familiar with the information submitted in this document and all attachments thereto, and I certify that based on reasonable investigation, including my inquiry of the individuals responsible for obtaining the information, the submitted information is true, accurate and complete to the best of my knowledge and belief.

I understand that a false statement in the submitted information may be punishable as a criminal offense, in accordance with Section 22a-6 of the General Statutes, pursuant to Section 53a-157b of the General Statutes, and in accordance with any other applicable statute.

I certify that this application is on complete and accurate forms as prescribed by the commissioner without alteration of the text.

I certify that I will comply with all notice requirements as listed in Section 22a-6g of the General Statutes.

Signature of Applicant — Date: 2/9/07

Paul Thessen
Name of Applicant (print or type)

Executive Vice President
Title (if applicable)

Signature of Preparer — Date: 2/15/07

Richard J Londergan
Name of Preparer (print or type)

Senior Program Director
Title (if applicable)

☐ Please enter a check mark if additional signatures are necessary. If so, please reproduce this sheet and attach signed copies to this sheet.

Attachment A: Executive Summary

Applicant Name as indicated on the *Permit Application Transmittal Form* (DEP-APP-001):

Bridgeport Energy II, LLC

Location of Facility or Activity: **Atlantic Street and Russell Street, Bridgeport, CT 06640**

Contact Person: **Blake Wheatley** Phone: **636-532-2200**

For Renewals, Modifications, and Revisions provide the following:

Existing Permit or Registration #: Expiration Date: / /

Provide a Table of Contents of the application which includes the *Permit Application Transmittal Form* (DEP-APP-001), the Permit Application Form (DEP-AIR-APP-100 or 200), and a list of all supplemental application forms, plans, drawings, reports, studies, or other supporting documentation which are attached as part of the application, along with the corresponding attachment label and the number of pages (e.g., Executive Summary - Attachment A - 4 pgs.).

The attached Application Document contains the Executive Summary and Table of Contents, plus a narrative description of the proposed source and associated emission controls. Completed Application Forms, aside from APP-AIR-200 and APP-AIR-222, are provided in Appendix A of the Application Document.

Bridgeport Energy II, LLC (BEII) is proposing to build and operate a new 350 MW nominal simple cycle combustion turbine generating facility in Bridgeport, CT. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. The project will be called the Bridgeport Peaking Station (BPS). The new facility will be located south of the existing Bridgeport Energy facility on a parcel adjacent to the western boundary of the existing Bridgeport Harbor Station property. The BEII facility will owned and operated separately from the existing Bridgeport Energy generating station.

The Project will utilize either two (2) General Electric (GE) model 7FA or Siemens model SGT-5000F turbines. BEII is currently evaluating the availability and cost of these two turbines but has not yet made a final decision on turbine technology. Accordingly, this application presents information for both turbine models. BEII will provide the Connecticut Department of Environment Protection (CTDEP) with the selected turbine model prior to commencing construction.

(continued next page)

(OVER)

Attachment A: Executive Summary (continued)

Provide a brief project description which includes: a description of the proposed regulated activities; a synopsis of the environmental and engineering analyses; summaries of data analysis; a conclusion of any environmental impacts and the proposed timeline for construction. For renewals, modifications, and revisions, provide a list of changes in circumstances or information on which the previous permit was based.

BEII is proposing to limit total annual operating hours and annual hours firing ULSD, and proposes to install selective catalytic reduction (SCR) to minimize NOx emissions. The application of these operation and pollution controls will limit emissions of all pollutants below the Prevention of Significant Deterioration (PSD) major source thresholds with the exception of CO and NOx. BPS will also be a non-attainment new source review (NNSR) new major source for NOx emissions with potential emissions above 25 tons per year (tpy).

The NNSR regulations require that a new major source install Lowest Achievable Emission Rate (LAER) technology to reduce emissions to the lowest level technically feasible. Therefore, BEII has proposed to install SCR on the turbines to achieve the lowest NOx emissions of any simple-cycle “F” class turbine operating in the United States. Additionally, CTDEP regulations require the application of Best Available Control Technology (BACT) for any pollutants with a potential to emit above 15 tpy for any emission unit. A BACT analysis is also provided for emissions of SO2, particulate matter (PM/PM10/PM2.5), carbon monoxide, VOCs and ammonia (NH3).

The two proposed combustion turbines will comprise the two primary air pollutant emission sources from the project. BPS will also include a 1.2 million gallon backup fuel oil tank that will have minor VOC emissions. The project will not include any supporting diesel fired emergency engines or cooling towers.

☐ If additional sheets are necessary, please label and attach them to this sheet and enter a check mark.

Applicant Background Information

Please enter a check mark by the entity which best describes the applicant and complete the requested information. **You must choose one of the following.**

☐ **Corporation**

1. Parent Corporation

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Contact Person: Title:

2. Subsidiary Corporation:

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Contact Person: Title:

3. Directors:

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

4. Officers:

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

Applicant Background Information (continued)

☒ **Limited Liability Company**

1. List each member.

Name: **LS Power Generation, LLC**
Mailing Address: **Two Tower Center, 11th Floor**
City/Town: **East Brunswick** State: **NJ** Zip Code: **08816-**
Business Phone: **732-249-6750** ext. Fax: **732-249-7290**

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

2. List any manager(s) who, through the articles of organization, are vested the management of the business, property and affairs of the limited liability company.

Name: **Paul G. Thessen, Executive Vice President**
Mailing Address: **400 Chesterfield Center, Suite 110**
City/Town: **St. Louis** State: **MO** Zip Code: **63017-**
Business Phone: **636-532-2200** ext. Fax: **636-532-2250**

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

Applicant Background Information (continued)

☐ **Limited Partnership**

1. General Partners:

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

2. Limited Partners:

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

Name:

Mailing Address:

City/Town: State: Zip Code: -

Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

Applicant Background Information (continued)

☐ **General Partnership**

1. General Partners:

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

Applicant Background Information (continued)

☐ **Voluntary Association**

1. List authorized persons of association or list all members of association.

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

☐ **Individual or Other Business Type**

1. Name:
Mailing Address:
City/Town: State: Zip Code: -
Business Phone: - - ext. Fax: - -

2. State other names by which the applicant is known, including business names.
Name:

☐ Please enter a check mark, if additional sheets are necessary. If so, label and attach additional sheet(s) to this sheet with the required information as supplied above.

Latitude and Longitude

Applicant Name: **Bridgeport Energy II, LLC**
(as indicated on the *Permit Application Transmittal Form*)

Method of latitude and longitude determination (check one):

☐ Global Positioning System (GPS) ☒ USGS Map ☐ Other (please specify)

In the table below, label each point for which latitude and longitude were measured, being consistent with identification numbers assigned throughout the application (e.g., 100, 101, etc.). For renewals or modifications of existing permits, please provide the existing permit number. Also provide: a brief description of the point (e.g., monitoring well, pipe outlet, air stack, etc.); latitude and longitude in degrees, minutes and seconds (e.g., 41E 16' 29"); and the name of the USGS quadrangle map(s) the points described are located on.

ID Number	Permit Number	Description	Latitude	Longitude	Quad Map Name	For DEP Use Only: GIS ID
S1		**Stack for Unit 1**	**41d 10m 06.08s N**	**73d 11m 00.53s W**		
S2		**Stack for Unit 2**	**41d 10m 04.97s N**	**73d 11m 00.18s W**		

Supplemental Application Form
Stack Parameters

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on *Permit Application Transmittal Form)*

DEP USE ONLY
App. No.: ____________
EPE No.: ____________

Section I. Stack Parameters (Make additional copies, if necessary)

Stack No. (1)	Unit No.(s) (2)	Control Equipment No.(s) (3)	Height ft. (4)	Diameter ft. (5)	Temp ^oF (6)	Flow ACFM (7)	Exit Dir. H or V (8)	Rain Hat Y or N (9)	Stack Lining (10)	Distance to Property Line ft. (11)
S1	U1	C1	213.25	24.0	820	233,6645	V	N	N	56.
S2	U2	C2	213.25	24.0	820	233,6645	V	N	N	52.

Supplemental Application Form
Unit Emissions

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form*)

DEP USE ONLY
App. No.:
EPE No.:

Section I: General Information

Please complete a separate form for each unit.

1. Unit Number: **U1**
2. Stack Number: **S1**
3. Control Equipment Number(s): **C1**

Section II: Stack Emission Information for Listed Pollutants (Exclude Fugitive Emissions)

Pollutant		(1) Stack Emission Rate (@ *Rated Capacity*)			
		Pounds Per Hour (lb/hr) (a)	Tons Per Year (TPY) (b)	Other (Units) (c)	Basis (d)
Carbon Monoxide (CO)	Uncontrolled potential	**80.0**	**350.4**		**Manufacturer (firing ULSD)**
	proposed actual	**80.0**	**162.4**		**Limit fuel and operating hours, include SUSD**
Volatile Organic Compounds (VOC)	uncontrolled potential	**12.0**	**52.6**		**Manufacturer (firing ULSD)**
	proposed actual	**12.0**	**12.3**		**Limit fuel and operating hours, include SUSD**
Exempted Volatile Organic Compounds	uncontrolled potential				**Not estimated**
	proposed actual				**Not estimated**
Hydrocarbons	uncontrolled potential				**Not estimated**
	proposed actual				**Not estimated**
Nitrogen Oxides (NOx)	uncontrolled potential	**350.0**	**1533.**		**Manufacturer (firing ULSD)**
	proposed actual	**125.0**	**67.85**		**SCR control, limit fuel and operating hours, add SUSD**
Sulfur Oxides (SOx)	uncontrolled potential	**3.27**	**14.3**		**Mass balance**
	proposed actual	**3.27**	**2.86**		**Limit fuel and operating hours.**
Particulate Matter (TSP)	uncontrolled potential	**60.0**	**262.8**		**Manufacturer (firing ULSD)**
	proposed actual	**60.0**	**24.6**		**Limit fuel and operating hours**
Particulate Matter <- 10 Micrometers (PM_{10})	uncontrolled potential	**60.0**	**262.8**		**Manufacturer (firing ULSD)**
	proposed actual	**60.0**	**24.6**		**Limit fuel and operating hours**
Lead (Pb)	uncontrolled potential	**0.03**	**0.13**		**Mass balance**
	proposed actual	**0.03**	**0.012**		**Limit fuel and operating hours**

Section III: Stack Emission Information for Hazardous Air Pollutants
(Exclude Fugitive Emission Information)

Hazardous Air Pollutants *(List Separately)* (1)		Stack Emission Rate (@ *Rated Capacity)* (2)				
		Pounds Per Hour (lb/hr) (a)	Tons per year (TPY) (b)	Concentration Micrograms Per Cubic Meter ($\mu g/m^3$) (c)	Other (Units) (d)	Basis (e)
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					

Section IV: Fugitive Emission Information for Listed Pollutants

Pollutant		Emission Rate (@ *Rated Capacity*) (1)			
		Pounds Per Hour (lb/hr) (a)	Tons Per Year (TPY) (b)	Other (Units) (c)	Basis (d)
Carbon Monoxide (CO)	uncontrolled potential				
	proposed actual				
Volatile Organic Compounds (VOC)	uncontrolled potential				
	proposed actual				
Exempted Volatile Organic Compounds	uncontrolled potential				
	proposed actual				
Hydrocarbons	uncontrolled potential				
	proposed actual				
Nitrogen Oxides (NOx)	uncontrolled potential				
	proposed actual				
Sulfur Oxides (SO_X)	uncontrolled potential				
	proposed actual				
Particulate Matter (TSP)	uncontrolled potential				
	proposed actual				
Particulate Matter <- 10 Micrometers (PM_{10})	uncontrolled potential				
	proposed actual				
Lead (Pb)	uncontrolled potential				
	proposed actual				

1e. Assumptions:

Section V: Fugitive Emission Information for Hazardous Air Pollutants

Hazardous Air Pollutants *(List Separately)* (1)		Emission Rate (@ *Rated Capacity)* (2)				
		Pounds Per Hour (lb/hr) (a)	Tons per year (TPY) (b)	Concentration Micrograms Per Cubic Meter ($\mu g/m^3$) (c)	Other (Units) (d)	Basis (e)
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					

Supplemental Application Form
Unit Emissions

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY
App. No.:
EPE No.:

Section I: General Information

Please complete a separate form for each unit.

1. Unit Number: **U2**
2. Stack Number: **S2**
3. Control Equipment Number(s): **C2**

Section II: Stack Emission Information for Listed Pollutants (Exclude Fugitive Emissions)

Pollutant		(1) Stack Emission Rate (@ *Rated Capacity*)			
		Pounds Per Hour (lb/hr) (a)	Tons Per Year (TPY) (b)	Other (Units) (c)	Basis (d)
Carbon Monoxide (CO)	Uncontrolled potential	**80.0**	**350.4**		**Manufacturer (firing ULSD)**
	proposed actual	**80.0**	**162.4**		**Limit fuel and operating hours, include SUSD**
Volatile Organic Compounds (VOC)	uncontrolled potential	**12.0**	**52.6**		**Manufacturer (firing ULSD)**
	proposed actual	**12.0**	**12.3**		**Limit fuel and operating hours, include SUSD**
Exempted Volatile Organic Compounds	uncontrolled potential				**Not estimated**
	proposed actual				**Not estimated**
Hydrocarbons	uncontrolled potential				**Not estimated**
	proposed actual				**Not estimated**
Nitrogen Oxides (NOx)	uncontrolled potential	**350.0**	**1533.**		**Manufacturer (firing ULSD)**
	proposed actual	**125.0**	**67.85**		**SCR control, limit fuel and operating hours, add SUSD**
Sulfur Oxides (SOx)	uncontrolled potential	**3.27**	**14.3**		**Mass balance**
	proposed actual	**3.27**	**2.86**		**Limit fuel and operating hours.**
Particulate Matter (TSP)	uncontrolled potential	**60.0**	**262.8**		**Manufacturer (firing ULSD)**
	proposed actual	**60.0**	**24.6**		**Limit fuel and operating hours**
Particulate Matter <- 10 Micrometers (PM_{10})	uncontrolled potential	**60.0**	**262.8**		**Manufacturer (firing ULSD)**
	proposed actual	**60.0**	**24.6**		**Limit fuel and operating hours**
Lead (Pb)	uncontrolled potential	**0.03**	**0.13**		**Mass balance**
	proposed actual	**0.03**	**0.012**		**Limit fuel and operating hours**

Section III: Stack Emission Information for Hazardous Air Pollutants
(Exclude Fugitive Emission Information)

Hazardous Air Pollutants *(List Separately)* (1)		Stack Emission Rate (@ *Rated Capacity*) (2)				
		Pounds Per Hour (lb/hr) (a)	Tons per year (TPY) (b)	Concentration Micrograms Per Cubic Meter ($\mu g/m^3$) (c)	Other (Units) (d)	Basis (e)
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					

Section IV: Fugitive Emission Information for Listed Pollutants

Pollutant		Emission Rate (@ *Rated Capacity*) (1) Pounds Per Hour (lb/hr) (a)	Tons Per Year (TPY) (b)	Other (Units) (c)	Basis (d)
Carbon Monoxide (CO)	uncontrolled potential				
	proposed actual				
Volatile Organic Compounds (VOC)	uncontrolled potential				
	proposed actual				
Exempted Volatile Organic Compounds	uncontrolled potential				
	proposed actual				
Hydrocarbons	uncontrolled potential				
	proposed actual				
Nitrogen Oxides (NOx)	uncontrolled potential				
	proposed actual				
Sulfur Oxides (SO_X)	uncontrolled potential				
	proposed actual				
Particulate Matter (TSP)	uncontrolled potential				
	proposed actual				
Particulate Matter <- 10 Micrometers (PM_{10})	uncontrolled potential				
	proposed actual				
Lead (Pb)	uncontrolled potential				
	proposed actual				

1e. Assumptions:

Section V: Fugitive Emission Information for Hazardous Air Pollutants

Hazardous Air Pollutants *(List Separately)* (1)		Emission Rate (@ *Rated Capacity*) (2)				
		Pounds Per Hour (lb/hr) (a)	Tons per year (TPY) (b)	Concentration Micrograms Per Cubic Meter ($\mu g/m^3$) (c)	Other (Units) (d)	Basis (e)
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					
	uncontrolled potential					
	proposed actual					
	maximum allowable					

Supplemental Application Form
Air Pollution Control Equipment

DEP USE ONLY	
App. No.:	
EPE No.:	

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on *Permit Application Transmittal Form)*

Section I. Summary Sheet (Make additional copies, if necessary)

Unit Number (1)	Unit Description (2)	Control Equipment		Overall Control Efficiency % (5)	Pollutants Controlled (6)	*Basis (7)	Stack No. (8)
		No. (3)	Type (4)				
U1	**comb. turbine**	**C1**	**SCR**	**66.6 NG**	**NOx**	**manufacturer**	**S1**
U1	**comb. turbine**	**C1**	**SCR**	**64.3 oil**	**NOx**	**manufacturer**	**S1**
U2	**comb. turbine**	**C2**	**SCR**	**66.6 NG**	**NOx**	**manufacturer**	**S2**
U2	**comb. turbine**	**C2**	**SCR**	**64.3 oil**	**NOx**	**manufacturer**	**S2**

** Attach supporting documentation with this form, e.g., stack test data, manufacturer's guarantee, etc.*

Section II: Specific Control Equipment

(Complete the appropriate subsection for each *distinct* piece of control equipment you utilize. You may reproduce the pages of the form as necessary.)

Adsorption Device

1a. Designated Reference Number of Adsorption Unit:

1b. Designated Reference Number of Unit which uses Adsorber:

2. Manufacturer:

3. Model Name & Number:

4. Construction Date: / /

5. Adsorbent:

☐ Activated Charcoal Type:

☐ Other (specify):

6. Number of Beds:

7. Dimensions of Bed

Bed No.1

Thickness in direction of gas flow(inches): Cross-section area (sq. inches):

Bed No.2

Thickness in direction of gas flow(inches): Cross-section area (sq. inches):

Bed No.3

Thickness in direction of gas flow(inches): Cross-section area (sq. inches):

8. Inlet Gas Temperature: ^{o}F or ^{o}C

9. Design Pressure Drop Across Unit: inches H_2O

10. Type of Regeneration

☐ Replacement ☐ Steam ☐ Other (specify):

11. Method of Regeneration

☐ Alternate use of beds ☐ Source shut down ☐ Other (specify):

Describe procedures used to ensure that emissions from regeneration process are treated or minimized:

12. Maximum Operation Time Before Regeneration:

13. Is adsorber equipped with a break-through detector? ☐ Yes ☐ No

14. a) Control Efficiency(s) of Adsorber (%):

b) Collection Efficiency(s) of Adsorber (%):

15. Pollutant(s) Controlled:

Afterburner (Incinerator for Air Pollution Control)

1a. Designated Reference Number of Afterburner:

1b. Designated Reference Number of Unit which uses Afterburner:

2. Manufacturer:

3. Model Name & Serial Number:

4. Construction Date: / /

5. Type of Afterburner: ☐ Thermal ☐ Catalytic ☐ Other (specify):

6. Combustion Chamber Dimensions

   Length (inches): Cross-section area (sq. inches):

7. Inlet Gas Temperature: ^{o}F *or* ^{o}C

8. Operating Temperature of Chamber: ^{o}F *or* ^{o}C

9. Type of Auxiliary Fuel: Higher Heating Value:

10. a)% Sulfur: b)% Ash: c)% Nitrogen:

11. Maximum Auxiliary Fuel Usage (specify units): a) Hourly:

    b) Annually:

12. Number of Burners Per Afterburner:

    Burner No. 1 @: BTU per hour

    Burner No. 2 @: BTU per hour

    Burner No. 3 @: BTU per hour

13. Catalyst Used: ☐ Yes ☐ No

    Type of Catalyst:

14. Catalyst Sampling Interval:

15. Heat Exchanger Used: ☐ Yes ☐ No

    Type of Heat Exchanger:

    Heat Recovery:

16. Gas Flow Rate (scfm):

17. Combustion Chamber Design Residence Time (seconds):

18. Moisture Content of Exhaust Gas (%):

19. a) Control Efficiency of Afterburner (%):

    b) Collection Efficiency of Afterburner (%):

20. Pollutant(s) Controlled:

Condenser

1a. Designated Reference Number of Condenser Unit:

1b. Designated Reference Number of Unit which uses Condenser:

2. Manufacturer:

3. Model Name & Number:

4. Construction Date: / /

5. Heat Exchange Area (sq. ft.):

6. Coolant Flow Rate: ☐ Water: gpm ☐ Air: scfm (at 68^{o} F)

☐ Other (specify) : Type: Flow Rate:

7. Gas Flow Rate: scfm (at 68^{o} F)

8. Coolant Temperature (^{o}F): In: Out:

9. Gas Temperature (^{o}F): In: Out:

10. a) Control Efficiency(s) of Condenser:

b) Collection Efficiency(s) of Condenser (%):

11. Pollutant(s) Controlled:

Electrostatic Precipitator

1a. Designated Reference Number of Electrostatic Precipitator:

1b. Designated Reference Number of Unit which uses Electrostatic Precipitator:

2. Manufacturer:

3. Model Name & Serial Number:

4. Construction Date: / /

5. Collecting Electrode Area (sq ft):

6. Gas Flow Rate (scfm):

7. Voltage Across the Precipitator Plates (kv):

8. Resistivity of Pollutants (ohms):

9. Number of Fields in the Precipitator:

10. Grain Loading (grains/scf @ 68^{o} F): a) Inlet: b) Outlet:

11. a) Control Efficiency(s) of Electrostatic Precipitator (%):

b) Collection Efficiency(s) of Electrostatic Precipitator (%):

12. Pollutant(s) Controlled:

Filter

1a. Designated Reference Number of Filter:
1b. Designated Reference Number of Unit which uses Filter:
2. Manufacturer:
3. Model Name & Serial Number:
4. Construction Date: / /
5. Filtering Material:
6. Air to Cloth Ratio (sq ft):
7. Cleaning Method: ☐ Shaker ☐ Reverse Air ☐ Pulse Air
☐ Pulse Jet ☐ Other (specify):
8. Gas Cooling Method: ☐ Ductwork Length (ft): Diameter (inches):
☐ Heat Exchanger ☐ Bleed-in Air ☐ Water Spray ☐ Other (specify):
9. Gas Flow Rate (from source): scfm (at 68 F)
10. Cooling Gas Flow Rate
Bleed-in Air: scfm (at 68 F) Water Spray: gpm
11. Inlet Gas Condition Temperature (F): Dew Point (F):
12. Grain Loading (grains/scf @ 68^o F): a) Inlet: b) Outlet:
13. Design Pressure Drop Across Unit (inches H_2O):
14. a) Control Efficiency of Filter (%):
b) Collection Efficiency of Filter (%):
15. Pollutant(s) Controlled:

Cyclone

1a. Designated Reference Number of Cyclone:
1b. Designated Reference Number of Unit which uses Cyclone:
2. Manufacturer:
3. Model Name & Serial Number:
4. Construction Date: / /
5. Type of Cyclone: ☐ Single ☐ Multiple
6. Number of Cyclones in Multiple Cyclone:
7. Gas Flow Rate: scfm (at 68^o F)
8. Grain Loading (grains/SCF @ 68^o F): a) Inlet: b) Outlet:
9. Design Pressure Drop Across Unit (inches H_2O):
10. a) Control Efficiency of Cyclone (%):
b) Collection Efficiency of Cyclone (%):
11. Pollutant(s) Controlled:

Scrubber

1a. Designated Reference Number of Scrubber:

1b. Designated Reference Number of Unit which uses Scrubber:

2. Manufacturer:

3. Model Name & Serial Number:

4. Construction Date: / /

5. Type of Scrubber: ☐ Venturi ☐ Wet Fan

☐ Packed: Packing Material:

Size: Packed Height (inches):

☐ Spray: Number of Nozzles:

Nozzle No. 1 Pressure (psig):

Nozzle No. 2 Pressure (psig):

Nozzle No. 3 Pressure (psig):

Nozzle No. 4 Pressure (psig):

☐ Other (specify): ***(Attach description and sketch with dimensions)***

6. Design Pressure Drop Across the Scrubber (inches H_2O):

7. Type of Flow: ☐ Concurrent ☐ Countercurrent ☐ Crossflow

8. Scrubber Geometry

Length in direction of Gas Flow (ft): Cross Sectional Area (sq ft):

9. Chemical Composition of Scrubbing Liquid:

10. a. Scrubbing Liquid Flow Rate (gpm):

b. Fresh Liquid Make-Up Rate (gpm):

11. Scrubber Liquid: ☐ One Pass ☐ Recirculated

12. Gas Flow Rate: scfm (at 68 F)

13. Inlet Gas Temperature (^oF):

14. a) Control Efficiency(s) of Scrubber (%):

b) Collection Efficiency(s) of Scrubber (%):

15. Pollutant(s) Controlled:

Mist Eliminator

1a. Designated Reference Number of Mist Eliminator:
1b. Designated Reference Number of Unit which uses Mist Eliminator:
2. Manufacturer:
3. Model Name & Number:
4. Construction Date: / /
5. Face Velocity (feet per second):
☐ Vertical Flow ☐ Horizontal Flow ☐ Diagonal
6. Design Pressure Drop Across Mist Eliminator (inches H_2O):
7. a) Control Efficiency of Mist Eliminator at:
1 mm Hg: 5 mm Hg: 10 mm Hg:
b) Collection Efficiency of Mist Eliminator (%):
8. Pollutant(s) Controlled:

Other Type of Control Equipment for Degreasing Equipment

1a. Designated Reference Number of Equipment:
1b. Designated Reference Number of Unit which uses Equipment:
2. Manufacturer:
3. Model Name & Serial Number:
4. Construction Date: / /
5. Method of Controls
☐ Refrigerator Chiller ☐ Water Spray ☐ Other (specify):
6. a) Control Efficiency of Other Type of Control Equipment (%):
b) Collection Efficiency of Other Type of Control Equipment (%):
7. Pollutant(s) Controlled:

Other Type of Control Equipment

1a. Designated reference number of other type of control equipment: **C1 and C2**
1b. Designated reference number of unit which uses other type of control equipment: **U1 and U2**
2. Manufacturer: **Peerless**
3. Model Name & Serial Number: **N/A (custom)**
4. Construction Date: / /
5. Generic name of other equipment: **Selective catalytic reduction unit**
6. a) Control efficiency of other type of control equipment (%): **64.3**
b) Collection efficiency of other type of control equipment (%):**100**
7. Pollutant(s) Controlled: **NOx**

PEERLESS MFG. CO.

CORPORATE HEADQUARTERS
14651 NORTH DALLAS PARKWAY
SUITE 500
DALLAS, TEXAS 75254

TELEPHONE (214) 357-6181
FAX (214) 351-0194
www.peerlessmfg.com

May 14, 2007

LS Power Development, LLC
Attention: Mr. Andrew Degon
Two Tower Center, 11th Floor
East Brunswick, NJ 08816

RE: PERFORMANCE WARRANTY
LS POWER PEAKERS
SIMPLE-CYCLE F-CLASS COMBUSTION TURBINE
PEERLESS REFERENCE: SCR-4004

Dear Mr. Degon,

This letter will provide your written statement that we can meet the guarantees as shown below based on your e-mail dated April 13, 2007 for a simple cycle F-class combustion turbine:

<u>Gas firing</u>
NOx, turbine exit – 9 ppm
NOx, SCR exit – 3 ppm
Slip – 6 ppm
Averaging time – 3 hour block

<u>Oil firing</u>
NOx, turbine exit – 42 ppm
NOx, SCR exit – 15 ppm
Slip – 6 ppm
Averaging time – 3 hour block

If you have any questions, or require additional information, please do not hesitate to contact me at 214-357-6181 or via email, tshippy@peerlessmfg.com.

Sincerely,

Tim T. Shippy
SCR Product Manager
Peerless Mfg. Co.

cc: file, Royce Stout-Kohl Equipment,

Supplemental Application Form
Fuel Burning Equipment

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY
App. No.: ____________
EPE No.: ____________

Please complete a separate form for *each* fuel burning unit.
(You may reproduce this form as necessary.)
Unit #: **1**

Is this unit subject to Title 40 CFR Part 60, NSPS? ☒ Yes or ☐ No

If yes, indicate the subpart(s): **GG**

Is this unit subject to Title 40 CFR Part 63, MACT? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Section I: General

1. Type of Unit (make, model, serial no.): **General Electric 7FA**
2. Burner (make, model, serial no.): **N/A**
3. Construction Date: / /
4. Unit Rated Capacity - Input (BTU/hr): **2,100,000,000**
5. Burner Rated Capacity - Input (if different) (BTU/hr): **N/A**
6. Engine Brake Horsepower (for internal combustion engines): **N/A**
7. Equipment is: ☐ Emergency ☒ Non-emergency
8. Maximum Operating Schedule for this Unit: **24** hours/day **2,500** hours/year
9. Percentage of Use in Each Category:
   Space Heat: **0** % Process Heat: **0** % Power: **100** %

Section II: Fuel

1. Type of Primary Fuel *(check one)*:
   ☐ Fuel Oil Grade *(check one)* ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6
   ☐ Coal ☒ Natural Gas ☐ Propane ☐ Butane ☐ Wood ☐ Landfill Gas
   ☐ Other *(specify)*:
   a. Maximum Fuel Firing Rate (specify units): **87,000 lb/hr**
2. List Secondary Fuel(s): **No. 2 fuel oil**
   a. Maximum Fuel Firing Rate for each secondary fuel listed (specify units): **108,300 lb/hr**

Section II: Fuel (continued)

3. Fuel Characteristics

Type	Percent Ash (a)	Percent Sulfur (b)	Percent Nitrogen (c)	Heating Value (d)	Annual Usage (e)
Primary	**Negl.**	**0.0008**	**N/A**	**20,423**	**2.175e8**
Secondary	**Negl.**	**0.0015**	**N/A**	**18,300**	**5.415e7**
Secondary					
Secondary					

4. Percent of Annual Fuel Use by Quarter:

1st: **25** % 2nd: **25** % 3rd: **25** % 4th: **25** %

Section III: Equipment

1. Oil-Fired/Gas-Fired Unit

☐ Tangentially Fired ☐ Horizontally Opposed (normal) Fired

☒ Other (specify): **Combustion turbine**

2. Coal Fired Units

☐ *Pulverized Coal Fired:*

☐ Dry Bottom ☐ Wet Bottom ☐ Wall Fired ☐ Tangentially Fired

☐ *Stoker:*

☐ Overfeed ☐ Underfeed ☐ Spreader ☐ Hand Fed

☐ Other (specify):

☐ *Fluidized Bed Combuster:*

☐ Circulating Bed ☐ Bubbling Bed ☐ Cyclone Furnace

3. Wood-Fired Unit

☐ Dutch Oven/Fuel Cell Oven ☐ Stoker

☐ Suspension Firing ☐ Fluidized Bed Combustion (FBC)

Section IV: Combustion Controls

1. ☐ Fly Ash Reinjection 2. ☐ Flue Gas Recirculation 3. ☒ Low NOx Burners

4. ☒ Advanced Combustion Controls:

☒ Selective Catalytic Reduction ☐ Coal Reburn ☐ Gas Reburn ☐ Other

If other, please specify:

☐ Check here if a *Stationary Reciprocating Internal Combustion Engine – Compliance Assurance Form* (DEP-AIR-COMP-001) is attached.

Supplemental Application Form
Fuel Burning Equipment

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY	
App. No.:	
EPE No.:	

Please complete a separate form for *each* fuel burning unit.
(You may reproduce this form as necessary.)
Unit #: **2**

Is this unit subject to Title 40 CFR Part 60, NSPS? ☒ Yes or ☐ No

If yes, indicate the subpart(s): **GG**

Is this unit subject to Title 40 CFR Part 63, MACT? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Section I: General

1. Type of Unit (make, model, serial no.): **General Electric 7FA**
2. Burner (make, model, serial no.): **N/A**
3. Construction Date: / /
4. Unit Rated Capacity - Input (BTU/hr): **2,100,000,000**
5. Burner Rated Capacity - Input (if different) (BTU/hr): **N/A**
6. Engine Brake Horsepower (for internal combustion engines): **N/A**
7. Equipment is: ☐ Emergency ☒ Non-emergency
8. Maximum Operating Schedule for this Unit: **24** hours/day **2,500** hours/year
9. Percentage of Use in Each Category:
   Space Heat: **0** % Process Heat: **0** % Power: **100** %

Section II: Fuel

1. Type of Primary Fuel *(check one)*:
   ☐ Fuel Oil Grade *(check one)* ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6
   ☐ Coal ☒ Natural Gas ☐ Propane ☐ Butane ☐ Wood ☐ Landfill Gas
   ☐ Other *(specify)*:
   a. Maximum Fuel Firing Rate (specify units): **87,000 lb/hr**
2. List Secondary Fuel(s): **No. 2 fuel oil**
   a. Maximum Fuel Firing Rate for each secondary fuel listed (specify units): **108,300 lb/hr**

Section II: Fuel (continued)

3. Fuel Characteristics

Type	Percent Ash (a)	Percent Sulfur (b)	Percent Nitrogen (c)	Heating Value (d)	Annual Usage (e)
Primary	**Negl.**	**0.0008**	**N/A**	**20,423**	**2.175e8**
Secondary	**Negl.**	**0.0015**	**N/A**	**18,300**	**5.415e7**
Secondary					
Secondary					

4. Percent of Annual Fuel Use by Quarter:

1st: **25** % 2nd: **25** % 3rd: **25** % 4th: **25** %

Section III: Equipment

1. Oil-Fired/Gas-Fired Unit

☐ Tangentially Fired ☐ Horizontally Opposed (normal) Fired

☒ Other (specify): **Combustion turbine**

2. Coal Fired Units

☐ *Pulverized Coal Fired:*

☐ Dry Bottom ☐ Wet Bottom ☐ Wall Fired ☐ Tangentially Fired

☐ *Stoker:*

☐ Overfeed ☐ Underfeed ☐ Spreader ☐ Hand Fed

☐ Other (specify):

☐ *Fluidized Bed Combuster:*

☐ Circulating Bed ☐ Bubbling Bed ☐ Cyclone Furnace

3. Wood-Fired Unit

☐ Dutch Oven/Fuel Cell Oven ☐ Stoker

☐ Suspension Firing ☐ Fluidized Bed Combustion (FBC)

Section IV: Combustion Controls

1. ☐ Fly Ash Reinjection 2. ☐ Flue Gas Recirculation 3. ☒ Low NOx Burners

4. ☒ Advanced Combustion Controls:

☒ Selective Catalytic Reduction ☐ Coal Reburn ☐ Gas Reburn ☐ Other

If other, please specify:

☐ Check here if a *Stationary Reciprocating Internal Combustion Engine – Compliance Assurance Form* (DEP-AIR-COMP-001) is attached.

Supplemental Application Form
Fuel Burning Equipment

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY	
App. No.:	
EPE No.:	

Please complete a separate form for *each* fuel burning unit.
(You may reproduce this form as necessary.)
Unit #: **U1**

Is this unit subject to Title 40 CFR Part 60, NSPS? ☒ Yes or ☐ No

If yes, indicate the subpart(s): **GG**

Is this unit subject to Title 40 CFR Part 63, MACT? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Section I: General

1. Type of Unit (make, model, serial no.): **Siemens SGT6-5000F**
2. Burner (make, model, serial no.): **N/A**
3. Construction Date: / /
4. Unit Rated Capacity - Input (BTU/hr): **2,257,000,000 HHV**
5. Burner Rated Capacity - Input (if different) (BTU/hr): **N/A**
6. Engine Brake Horsepower (for internal combustion engines): **N/A**
7. Equipment is: ☐ Emergency ☒ Non-emergency
8. Maximum Operating Schedule for this Unit: **24** hours/day **2,500** hours/year
9. Percentage of Use in Each Category:
   Space Heat: **0** % Process Heat: **0** % Power: **100** %

Section II: Fuel

1. Type of Primary Fuel *(check one)*:
   ☐ Fuel Oil Grade *(check one)* ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6
   ☐ Coal ☒ Natural Gas ☐ Propane ☐ Butane ☐ Wood ☐ Landfill Gas
   ☐ Other *(specify)*:
   a. Maximum Fuel Firing Rate (specify units): **100,500 lb/hr**
2. List Secondary Fuel(s): **No. 2 fuel oil**
   a. Maximum Fuel Firing Rate for each secondary fuel listed (specify units): **109,300 lb/hr**

Section II: Fuel (continued)

3. Fuel Characteristics

Type	Percent Ash (a)	Percent Sulfur (b)	Percent Nitrogen (c)	Heating Value (d)	Annual Usage (e)
Primary	**Negl.**	**0.0008**	**N/A**	**20,418**	**2.513e8**
Secondary	**Negl.**	**0.0015**	**N/A**	**18,450**	**4.372e7**
Secondary					
Secondary					

4. Percent of Annual Fuel Use by Quarter:

1st: **25** % 2nd: **25** % 3rd: **25** % 4th: **25** %

Section III: Equipment

1. Oil-Fired/Gas-Fired Unit

☐ Tangentially Fired ☐ Horizontally Opposed (normal) Fired

☒ Other (specify): **Combustion turbine**

2. Coal Fired Units

☐ *Pulverized Coal Fired:*

☐ Dry Bottom ☐ Wet Bottom ☐ Wall Fired ☐ Tangentially Fired

☐ *Stoker:*

☐ Overfeed ☐ Underfeed ☐ Spreader ☐ Hand Fed

☐ Other (specify):

☐ *Fluidized Bed Combuster:*

☐ Circulating Bed ☐ Bubbling Bed ☐ Cyclone Furnace

3. Wood-Fired Unit

☐ Dutch Oven/Fuel Cell Oven ☐ Stoker

☐ Suspension Firing ☐ Fluidized Bed Combustion (FBC)

Section IV: Combustion Controls

1. ☐ Fly Ash Reinjection 2. ☐ Flue Gas Recirculation 3. ☒ Low NOx Burners

4. ☒ Advanced Combustion Controls:

☒ Selective Catalytic Reduction ☐ Coal Reburn ☐ Gas Reburn ☐ Other

If other, please specify:

☐ Check here if a *Stationary Reciprocating Internal Combustion Engine – Compliance Assurance Form* (DEP-AIR-COMP-001) is attached.

Supplemental Application Form
Fuel Burning Equipment

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY	
App. No.:	
EPE No.:	

Please complete a separate form for *each* fuel burning unit.
(You may reproduce this form as necessary.)
Unit #: **U2**

Is this unit subject to Title 40 CFR Part 60, NSPS? ☒ Yes or ☐ No

If yes, indicate the subpart(s): **GG**

Is this unit subject to Title 40 CFR Part 63, MACT? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Section I: General

1. Type of Unit (make, model, serial no.): **Siemens SGT6-5000F**
2. Burner (make, model, serial no.): **N/A**
3. Construction Date: / /
4. Unit Rated Capacity - Input (BTU/hr): **2,257,000,000 HHV**
5. Burner Rated Capacity - Input (if different) (BTU/hr): **N/A**
6. Engine Brake Horsepower (for internal combustion engines): **N/A**
7. Equipment is: ☐ Emergency ☒ Non-emergency
8. Maximum Operating Schedule for this Unit: **24** hours/day **2,500** hours/year
9. Percentage of Use in Each Category:
   Space Heat: **0** % Process Heat: **0** % Power: **100** %

Section II: Fuel

1. Type of Primary Fuel *(check one)*:
   ☐ Fuel Oil Grade *(check one)* ☐ 1 ☐ 2 ☐ 3 ☐ 4 ☐ 5 ☐ 6
   ☐ Coal ☒ Natural Gas ☐ Propane ☐ Butane ☐ Wood ☐ Landfill Gas
   ☐ Other *(specify)*:
   a. Maximum Fuel Firing Rate (specify units): **100,500 lb/hr**
2. List Secondary Fuel(s): **No. 2 fuel oil**
   a. Maximum Fuel Firing Rate for each secondary fuel listed (specify units): **109,300 lb/hr**

Section II: Fuel (continued)

3. Fuel Characteristics

Type	Percent Ash (a)	Percent Sulfur (b)	Percent Nitrogen (c)	Heating Value (d)	Annual Usage (e)
Primary	**Negl.**	**0.0008**	**N/A**	**20,418**	**2.513e8**
Secondary	**Negl.**	**0.0015**	**N/A**	**18,450**	**4.372e7**
Secondary					
Secondary					

4. Percent of Annual Fuel Use by Quarter:

1st: **25** % 2nd: **25** % 3rd: **25** % 4th: **25** %

Section III: Equipment

1. Oil-Fired/Gas-Fired Unit

☐ Tangentially Fired ☐ Horizontally Opposed (normal) Fired

☒ Other (specify): **Combustion turbine**

2. Coal Fired Units

☐ *Pulverized Coal Fired:*

☐ Dry Bottom ☐ Wet Bottom ☐ Wall Fired ☐ Tangentially Fired

☐ *Stoker:*

☐ Overfeed ☐ Underfeed ☐ Spreader ☐ Hand Fed

☐ Other (specify):

☐ *Fluidized Bed Combuster:*

☐ Circulating Bed ☐ Bubbling Bed ☐ Cyclone Furnace

3. Wood-Fired Unit

☐ Dutch Oven/Fuel Cell Oven ☐ Stoker

☐ Suspension Firing ☐ Fluidized Bed Combustion (FBC)

Section IV: Combustion Controls

1. ☐ Fly Ash Reinjection 2. ☐ Flue Gas Recirculation 3. ☒ Low NOx Burners

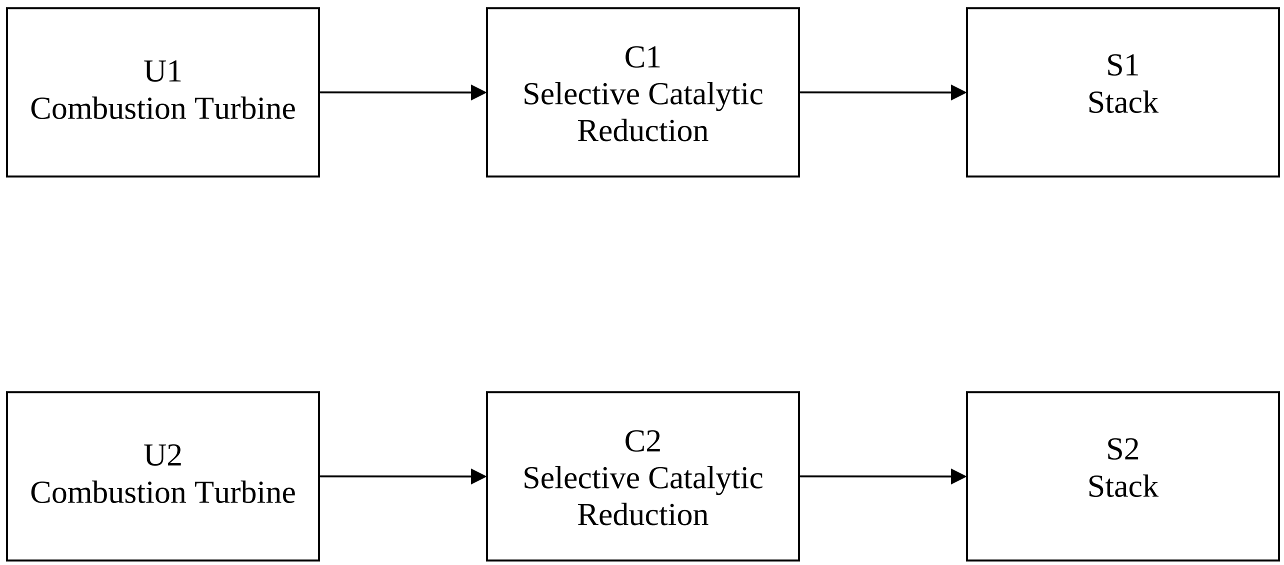
4. ☒ Advanced Combustion Controls:

☒ Selective Catalytic Reduction ☐ Coal Reburn ☐ Gas Reburn ☐ Other

If other, please specify:

☐ Check here if a *Stationary Reciprocating Internal Combustion Engine – Compliance Assurance Form* (DEP-AIR-COMP-001) is attached.

PROCESS FLOW DIAGRAM
Bridgeport Energy II, LLC
DEP-AIR-APP-202



Supplemental Application Form
Volatile Liquid Storage

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY	
App. No.:	
EPE No.:	

Please complete a separate form for each premise or tank farm.
(Reproduce this form as necessary.)

Unit No.: **1**

Is this unit subject to Title 40 CFR Part 60, NSPS? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Is this unit subject to Title 40 CFR Part 63, MACT? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Is the EPA Tank Software Program Output Attached? ☐ Yes or ☒ No

Section I: Product Information

Tank ID No. (1a)	Product Type (1b)	Density (lb/gal) (1c)	Molecular Weight (1d)	True Vapor Pressure (psi)	
				At Maximum Storage Temperature (1e)	At Annual Average Storage Temperature (1f)
1	#2 oil	7.2	~130	0.02	0.01

Section II: Bulk Gasoline Plants and Terminals Only

1. Is the tank farm a : ☐ Bulk Gasoline Plant? ☐ Bulk Gasoline Terminal?

2. For loading incoming gasoline into the storage tanks, is there a:

Submerged fill pipe?	☐ Yes	☐ No
Bottom fill?	☐ Yes	☐ No
Splash fill?	☐ Yes	☐ No

3. Is there a vapor balance system for:

Filling storage tanks from transport vehicle tanks?	☐ Yes	☐ No
Filling transport vehicle tanks from storage tanks?	☐ Yes	☐ No

4a. Is there a vapor recovery system for filling gasoline transport vehicles from storage tanks?

☐Yes ☐ No

4b. If yes, what type of vapor control device is used? (please specify)

Section III: Storage Tank Information

Part A: All New, Modified or Replacement Storage Tanks

Tank ID No. (1)	Constructio n Date (2)	Tank Diameter (ft) (3)	Tank Height or Length (ft) (4)	Maximum Hourly Filling Rate (gal/hr) (5)	Maximum Annual Throughput (gal/yr) (6)	Tank Capacity (gallon) (7)
T1		67.0	48.0		7,590,300	1,200,000

Part B: Fixed Roof Tanks Only

Part C: Variable Vapor Space Tanks Only

Tank ID No. (1)	Paint Color		Average Vapor Space Height (ft) (4)	Horizontal (H) or Vertical (V) (5)	Undergroun d (Yes/No) (6)	Tank ID No. (1)	Volume Expansion Capacity (gal) (2)	Number of Transfers into the Tanks per Year (3)
	Roof (2)	Sides (3)						
T1	White	White			No			

Section III: Storage Tank Information (continued)

Part D: All Floating Roof Tanks

Tank ID No. (1)	Riveted (R) or Welded (W) Tank Sides (2)	Type of Primary Seal (3)	Type of Secondary Seal (4)	Shell Condition (5)	Number of Support Columns (6)	Effective Column Diameter (ft) (7)

Part E: Internal Floating Roof Tanks Only

Tank ID No. (1)	Types of Deck Fittings (2)	Number of Each Type (3)	Design of Each Deck Fitting (4)	Number of Each Design (5)	Bolted Decks Only Length of Deck Seam (ft) (6)

Supplemental Application Form
Volatile Liquid Storage

Applicant Name: **Bridgeport Energy II, LLC**
(As indicated on the *Permit Application Transmittal Form)*

DEP USE ONLY	
App. No.:	
EPE No.:	

Please complete a separate form for each premise or tank farm.
(Reproduce this form as necessary.)

Unit No.: **2**

Is this unit subject to Title 40 CFR Part 60, NSPS? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Is this unit subject to Title 40 CFR Part 63, MACT? ☐ Yes or ☒ No

If yes, indicate the subpart(s):

Is the EPA Tank Software Program Output Attached? ☐ Yes or ☒ No

Section I: Product Information

Tank ID No. (1a)	Product Type (1b)	Density (lb/gal) (1c)	Molecular Weight (1d)	True Vapor Pressure (psi) At Maximum Storage Temperature (1e)	True Vapor Pressure (psi) At Annual Average Storage Temperature (1f)
2	**Ammonia**	**7.35**	**17.7**	**~25**	**~8**

Section II: Bulk Gasoline Plants and Terminals Only

1. Is the tank farm a : ☐ Bulk Gasoline Plant? ☐ Bulk Gasoline Terminal?

2. For loading incoming gasoline into the storage tanks, is there a:

Submerged fill pipe?	☐ Yes	☐ No
Bottom fill?	☐ Yes	☐ No
Splash fill?	☐ Yes	☐ No

3. Is there a vapor balance system for:

Filling storage tanks from transport vehicle tanks?	☐ Yes	☐ No
Filling transport vehicle tanks from storage tanks?	☐ Yes	☐ No

4a. Is there a vapor recovery system for filling gasoline transport vehicles from storage tanks?

☐Yes ☐ No

4b. If yes, what type of vapor control device is used? (please specify)

Section III: Storage Tank Information

Part A: All New, Modified or Replacement Storage Tanks

Tank ID No. (1)	Constructio n Date (2)	Tank Diameter (ft) (3)	Tank Height or Length (ft) (4)	Maximum Hourly Filling Rate (gal/hr) (5)	Maximum Annual Throughput (gal/yr) (6)	Tank Capacity (gallon) (7)
T2		8	30		115,000	12,000

Part B: Fixed Roof Tanks Only

Part C: Variable Vapor Space Tanks Only

Tank ID No. (1)	Paint Color		Average Vapor Space Height (ft) (4)	Horizontal (H) or Vertical (V) (5)	Undergroun d (Yes/No) (6)	Tank ID No. (1)	Volume Expansion Capacity (gal) (2)	Number of Transfers into the Tanks per Year (3)
	Roof (2)	Sides (3)						

Section III: Storage Tank Information (continued)

Part D: All Floating Roof Tanks

Tank ID No. (1)	Riveted (R) or Welded (W) Tank Sides (2)	Type of Primary Seal (3)	Type of Secondary Seal (4)	Shell Condition (5)	Number of Support Columns (6)	Effective Column Diameter (ft) (7)

Part E: Internal Floating Roof Tanks Only

Tank ID No. (1)	Types of Deck Fittings (2)	Number of Each Type (3)	Design of Each Deck Fitting (4)	Number of Each Design (5)	Bolted Decks Only Length of Deck Seam (ft) (6)

Attachment H
Emergency Episode Standby Plan

Regulations of Connecticut State Agencies (RCSA) Section 22a-174-6 identify the Air pollution emergency episode procedures. These regulations outline the criteria for determining the stage of an air pollution industrial emergency episode exists. Air pollutant concentrations are monitored by the Department and if indicated that short term high pollutant levels may be expected which are likely to have an adverse impact on human health, the Commissioner shall prepare for declaration of an appropriate air pollution emergency episode. There are three stages each determined by the concentration level of specific pollutants for a specific time period. The pollutants for all three stages are SO_2, PM_{10}, and NO_x. Once any stage of air pollution emergency episode has been declared, it shall remain in effect until the Commissioner announces it termination. The Commissioner can declare an industrial air pollution emergency episode in the aid of a sister state.

The regulation defines plans of action at each stage of an industrial air pollution emergency episode.

Bridgeport Energy II, LLC (BEII) is in the process of proposing to build and operate a new 350 MW nominal simple cycle combustion turbine generating facility in Bridgeport, CT. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil. The Project will utilize two turbines. The Emergency Standby Plan will take effect once the plant is constructed and in operation. The combustion turbines and associated equipment will emit emissions of nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter ($PM/PM_{10}/PM_{2.5}$), carbon monoxide (CO), volatile organic compounds (VOC), and ammonia (NH_3).

BEII will follow the plan of action as defined at each stage. Since the facility will have the potential to emit more than 100 tons per year of pollutants as determined before the application of control equipment, the facility shall put into effect the preplanned abatement strategy for an industrial air pollution alert. The preplanned abatement strategy is for the facility to prepare a standby plan for reducing the emission of air pollutants during each of the three stages of the industrial air pollution emergency episode. The three stages are Industrial Alert, Industrial Warnings and Industrial Emergency. The standby plan will be designed to reduce or eliminate emissions of air pollutant in accordance with the requirements set forth in the regulations for each of the three stages. More specific details on the amount of reduction to be achieved and the manner in which it will be accomplished will be provided once the turbines are in operation.

First Stage – Industrial Alert:

Electric power generation shall, when ever possible, be diverted to facilities outside the alert area. BEII will if possible not operate during the alert. If BEII must remain in operation, fuels having low ash and sulfur content will be used as per the regulations.

BEII will institute actions that will result in the reduction of air pollutants from their activities to the extent possible without causing injury to persons or damage to equipment while still providing necessary power.

Reduction in power for example may occur through the use of using only one combustion turbine unit instead of two or limiting hours of operation during the period of time. Until the facility is in operation and is part of the power grid, specific details regarding the amount of reduction to be achieved and the manner in which the reduction will be accomplished can not be provided.

The regulations also list that any boiler lancing or soot blowing required from fuel burning equipment shall be performed only be performed during the hours of 12 noon and 4 pm. BEII will not conduct these types of operations.

Steam loads demands and heat load demands for processing are required to be reduced by the regulations. Therefore, the demand for BEII maybe reduced during the alert.

Second Stage- Industrial Warning

Electric power generation shall, to the maximum extent possible, be diverted to facilities outside the warning area. BEII will if possible not operate during the alert. If BEII must remain in operation, fuels having low ash and sulfur content will be used and will operate at the most minimum level possible. BEII will institute actions that will result in the reduction of air pollutants from their activities to the most extent possible without causing injury to persons or damage to equipment while still providing power that has been deemed necessary.

Reduction in power for example may occur through the use of using only one combustion turbine unit instead of two or limiting hours of operation during the period of time. Until the facility is in operation and is part of the power grid, specific details regarding the amount of reduction to be achieved and the manner in which the reduction will be accomplished can not be provided.

The regulations also list that any boiler lancing or soot blowing required from fuel burning equipment shall be performed only be performed during the hours of 12 noon and 4 pm. BEII will not conduct these types of operations.

Steam loads demands and heat load demands for processing are required to be reduced to the maximum extent possible by the regulations. Manufacturing operations shall be ceased, curtailed, postponed, or deferred. Therefore, the demand for BEII may be reduced during the alert.

BEII will conduct no open burning.

Third Stage- Industrial Air Pollution Emergency

During the third stage there are a number of enterprises and activities that shall immediately cease operations, including, but not limited to, construction work, wholesale trade establishments, state and local government offices except those necessary for public safety and welfare including any involved in combating the industrial air pollution emergency, all retail trade establishments except pharmacies, and stores primarily engaged in the sale of food, banks, real estate offices, offices of insurance carriers, laundry services, beauty shops, advertising offices, all offices, clerical and professional service enterprises including law and accounting offices but excluding doctors' offices and medical laboratories, all schools of any kind, and establishments rendering amusement and recreational services. Therefore, the electrical demand of the area would be significantly reduced.

BEII will, to the maximum extent possible without causing injury to persons or damage to equipment, institute actions that will result in the maximum reduction of air pollutants from their activities by ceasing curtailing, or postponing operations which emit air pollutants.

Reduction in power for example may occur through the use of using only one combustion turbine unit instead of two or limiting hours of operation during the period of time or not operating the turbines during the emergency. Until the facility is in operation and is part of the power grid, specific details regarding the amount of reduction to be achieved and the manner in which the reduction will be accomplished can not be provided.

BEII will conduct no open burning.

Updates to the plan will be prepared as necessary when the facility is in operation.

Attachment I
Operation and Maintenance Manual

The Project will utilize either two (2) General Electric (GE) model 7FA or Siemens model SGT-5000F turbines operating in simple-cycle (peaking) mode. The turbines will have a collective nominal generating capacity of approximately 350 MW. The combustion turbines will fire natural gas as the primary fuel with limited backup firing of ultra low sulfur diesel (ULSD) fuel oil.

Both the GE 7FA and Siemens SGT-5000F turbines will utilize state-of-the-art dry low NO_x (DLN) combustors to minimize uncontrolled emissions of all pollutants from the project. An SCR will be incorporated to control NO_x emissions and meet LAER requirements. The proposed operating limitations for the facility also reduce potential annual emissions. These limitations include: annual operating hours of ≤2,500 hours per year (hr/yr) per turbine; ≤500 hours per year (hr/yr) of backup oil firing; and using ULSD as the backup fuel with a maximum sulfur content of 15 ppmw. Due to the application of SCR, there will be some ammonia emissions (i.e. "ammonia slip") associated with the project.

Baseload Operation

The combustion turbine manufacturers provided emission rate data for all criteria pollutants during normal operation. Normal operation has been defined as all operating modes above 75% load and with the SCR catalyst at its minimum operating temperature of about 500°F. The turbines will be operated in accordance with these guidelines and the operation procedures provided by the turbine vendor and by the SCR system vendor.

The facility will also comply with the requirements for the operation of air pollution control equipment in Sec. 22a-174-7(b) of the Regulations of Connecticut State Agencies. These requirements prohibit the deliberate shutdown of any air pollution control equipment while the turbines are operating, except for necessary maintenance that cannot be performed offline.

Startup/Shutdown Operation

The plant will be operate as a "peaking" plant meaning that it will operate during periods of peak demand, which are generally during weekdays with high or low ambient temperatures. Consequently, the turbines may be turned on and off on a daily basis. Under this operating scenario, the turbines would be started up and shut down each weekday. Accordingly, the project estimates that the maximum number of starts, and associated shutdowns, per year will be 250.

Emissions of NO_x, CO and VOC from combustion turbines may be significantly higher during start-up and shutdown (SUSD) conditions than during normal operation. Emissions of SO_2 and PM during SUSD operation are at or below their respective emission rates during normal operation and therefore there is no increase in emissions of these two pollutants as a result of SUSD operation. During start-up, the turbines cannot initially operate in lean pre-mix mode which results in higher emissions. A similar transition from lean pre-mix combustion to standard combustion occurs during shutdown. Also, the SCR catalyst is not effective until it reaches a minimum temperature of about 500°F.

The duration of startups and shutdowns for a combustion turbine in simple-cycle mode is relatively short. The facility will employ best management practices, in addition to operation procedures provided by the turbine vendor, to minimize emissions during startup and shutdown operation and to limit the number of starts per year to 250 per turbine.

Malfunctions

The turbines will be operated in accordance with operation procedures provided by the turbine vendor and by the SCR system vendor in cases of equipment malfunction.

The facility will also comply with the requirements for the breakdown, failure, and deliberate shutdown of air pollution control equipment in Sec. 22a-174-7(a) of the Regulations of Connecticut State Agencies. These requirements state that if the facility continues to operate an emission source while any air pollution control equipment is inoperative, the owner or operator will exercise due diligence to minimize emissions, continue the use of monitoring equipment, and give notice to the commissioner as required by Sec. 22a-174-7(d) and (e).

Maintenance

The facility will follow maintenance procedures provided by the turbine vendor and by the SCR system vendor.

Continuous Emission Monitoring Systems (CEMS)

The facility will operate CEMS for the measurement of NO_x, SO_2, NH_3, and opacity emissions from the turbine stacks. Each CEMS will be operated and maintained in accordance with monitoring plans and quality assurance/quality control (QA/QC) plans prepared to satisfy the requirements of 40 CFR 75.

Applicant Compliance Information

DEP ONLY
App. No. ____________________________
Co./Ind. No. __________________________

Applicant Name: **Bridgeport Energy II, LLC**
(as indicated on the *Permit Application Transmittal Form*)

If you answer *yes* to any of the questions below, you must complete the Table of Enforcement Actions on the reverse side of this sheet as directed in the instructions for your permit application.

A. During the five years immediately preceding submission of this application, has the applicant been convicted in any jurisdiction of a criminal violation of any environmental law?

☐ Yes ☒ No

B. During the five years immediately preceding submission of this application, has a civil penalty been imposed upon the applicant in any state, including Connecticut, or federal judicial proceeding for any violation of an environmental law?

☐ Yes ☒ No

C. During the five years immediately preceding submission of this application, has a civil penalty exceeding five thousand dollars been imposed on the applicant in any state, including Connecticut, or federal administrative proceeding for any violation of an environmental law?

☐ Yes ☒ No

D. During the five years immediately preceding submission of this application, has any state, including Connecticut, or federal court issued any order or entered any judgement to the applicant concerning a violation of any environmental law?

☐ Yes ☒ No

E. During the five years immediately preceding submission of this application, has any state, including Connecticut, or federal administrative agency issued any order to the applicant concerning a violation of any environmental law?

☐ Yes ☒ No

Table of Enforcement Actions

(1) Type of Action	(2a) Date Commenced	(2b) Date Terminated	(3) Jurisdiction	(4) Case/Docket/ Order No.	(5) Description of Violation

☐ Check the box if additional sheets are attached. Copies of this form may be duplicated for additional space.

Attachment L: Conformance Certification Form

I, **Paul Thessen of Bridgeport Energy II, LLC** , certify

(Name of applicant)

that each source of air pollution on the land where the subject activity is located conforms to the regulations adopted under Section 22a-174 of the Connecticut General Statutes and does not pose a health hazard.

Paul Thessen 2/9/07

Signature of Applicant Date

Paul Thessen
Name of Applicant (print or type)

Executive Vice President
Title (if applicable)

☐ Please enter a check mark if additional signatures are necessary (i.e., if there are co-applicants). If so, please reproduce this form as necessary and attach the signed copies to this sheet.

Appendix B

Supporting Calculations for Emission Rates and BACT Analysis

GE 7FA POTENTIAL EMISSIONS							
	Gas (lb/hr @ 59F)		Oil (lb/hr @ 3F)		Baseload PTE (tpy)	SUSD PTE Net Increase (tpy)	Facility PTE (tpy)
Pollutant	**100%**	**75%**	**100%**	**75%**			
NOx	20.0	17.0	123.0	99.0	101.5	34.2	135.7
CO	33.0	27.0	80.0	65.0	106.0	129.1	235.1
PM/PM10	15.0	15.0	34.0	34.0	47.0	0	47.0
SO2	2.05	1.67	3.24	2.61	5.72	0	5.72
VOC	3.10	2.60	12.5	10.1	12.5	12.2	24.8
NH3	14.8	11.9	18.7	14.9	39.0	0	39.0
H2SO4	0.37	0.30	0.58	0.47	1.0	0	1.0

Maximum Hours Per Year	2500	per CTG
Maximum Hours On Oil	500	per CTG
Number Of Starts Per Year	250	per CTG
Startup/Shutdown Hours Per Year	288	per CTG

VOC total includes 0.2 tpy from fuel oil storage tank

GE 7FA Startup & Shutdown Emissions - Gas						
	Gas 59F	**Startup/Shutdown Combined**				**PTE**
	Baseload				**Net Increase**	**Increase**
Pollutant	**(lbs/hr)**	**Duration (min)**	**(lbs)**	**(lbs/hr)**	**(lbs/hr)**	**(tpy)**
NOx	20.0	68.0	128.6	113.5	93.5	10.6
CO	33.0	68.0	563.6	497.3	464.3	52.6
VOC	3.10	68.0	39.5	34.9	31.8	3.60
Number of Gas Starts Per Year			200			
Startup/Shutdown Hours Per Year			227			

GE 7FA Startup & Shutdown Emissions - Oil						
	Oil 3F	**Startup/Shutdown Combined**				**PTE**
	Baseload				**Net Increase**	**Increase**
Pollutant	**(lbs/hr)**	**Duration (min)**	**(lbs)**	**(lbs/hr)**	**(lbs/hr)**	**(tpy)**
NOx	123.0	73.0	410.0	337.0	214.0	6.51
CO	80.0	73.0	575.0	472.6	392.6	11.94
VOC	12.5	73.0	115.0	94.5	82.0	2.49
Number of Oil Starts Per Year			50			
Oil Startup/Shutdown Hours Per Year			61			

GE 7FA Startup & Shutdown Emissions - Summary			
Pollutant	**PTE Increase - Gas Starts (tpy)**	**PTE Increase - Oil Starts (tpy)**	**Total PTE Increase**
NOx	10.6	6.5	17.1
CO	52.6	11.9	64.6
VOC	3.6	2.5	6.1
Total Number of Starts Per Year	250		
Number of Oil Starts Per Year	50		
Startup/Shutdown Hours Per Year	288		

GE 7FA	**time** (min)	**Emissions** (lbs) NOx	CO	VOC
startup on gas	39	69	417	28
shutdown on gas	29	59	147	12
startup on oil	46	256	298	60
shutdown on oil	27	154	277	55

CASE IDENTIFICATION										
Parameter	**Units**	**Comments**	**NG1**	**NG2**	**NG3**	**NG4**	**NG5**	**NG6**	**NG7**	**NG8**
Ambient dry bulb	^oF		3	3	59	59	75	75	94	94
Ambient wet bulb	^oF		1	1	52	52	69	69	76	76
CTG load	%		100%	75%	100%	75%	100%	75%	100%	75%
Evap cooler efficiency	%		0%	0%	85%	85%	85%	85%	85%	85%
Fuel			Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas
STACK SUMMARY										
Stack flow	ACFM		2,821,709	2,348,050	2,783,371	2,336,953	2,756,234	2,336,645	2,749,474	2,341,897
Stack flow	pph		5,186,088	4,317,204	5,097,854	4,282,399	5,029,048	4,265,452	5,009,278	4,269,067
Stack velocity	ft/sec		104.0	86.5	102.5	86.1	101.5	86.1	101.3	86.3
Stack Mole Wt.	lb/lb-mole		28.60	28.61	28.50	28.51	28.39	28.40	28.35	28.36
Stack temp	^oF	w/ heat loss	820	820	820	820	820	820	820	820
CTG heat consumption	MMBtu/h	HHV	1,955	1,586	1,801	1,469	1,737	1,426	1,701	1,400
CTG NOx	pph	As NO2	65.0	52.0	60.0	48.0	58.0	47.0	56.0	46.0
Stack NOx	ppmvd	@15%O2	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Stack NOx	pph	As NO2	22.00	18.0	20.0	17.0	20.0	16.0	19.0	16.0
Stack NOx-method 19	lb/MMBtu HHV	as NO2	0.011	0.011	0.011	0.011	0.011	0.011	0.011	0.011
Stack CO	ppmvd	@15% O2	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00
Stack CO	pph		36.0	29.0	33.0	27.0	32.0	26.0	31.0	26.0
Stack CO-method 19	lb/MMBtu HHV		0.018	0.018	0.018	0.018	0.018	0.018	0.018	0.018
Stack VOC	ppmvw	@15% O2	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Stack VOC-actual	pph	NMTHC	3.40	2.80	3.10	2.60	3.00	2.50	3.00	2.50
Stack VOC-method 19	lb/MMBtu HHV	NMTHC as CH4	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017	0.0017
SO2 emission	pph		2.23	1.81	2.05	1.67	1.98	1.62	1.94	1.59
Stack SO2-method 19	lb/MMBtu HHV		0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012
H2SO4 @stack	pph		0.40	0.32	0.37	0.30	0.35	0.29	0.35	0.29
H2SO4-method 19	lb/MMBtu HHV		0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
NH3	pph		16.0	12.9	14.8	11.9	14.2	11.6	13.9	11.4
NH3	ppmvd	@15%O2	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
PM10	pph		15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
PM10 - method 19	lb/MMBtu HHV		0.0077	0.0095	0.0083	0.0102	0.0086	0.0105	0.0088	0.0107
CTG INPUTS (PER CTG)										
CTG fuel LHV	Btu/lb		20,423	20,423	20,423	20,423	20,423	20,423	20,423	20,423
Relative humidity	%		42.40%	42.40%	62.70%	62.70%	74.30%	74.30%	44.30%	44.30%
Injection ratio	lb H2O/lb fuel		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CTG gross power	kW		190,300	142,700	171,900	129,000	163,600	122,700	158,800	119,100
CTG gross ht rate	Btu/kWh LHV		9265	10020	9445	10270	9575	10480	9660	10600
Exhaust flow	pph		5,185,977	4,317,115	5,097,751	4,282,316	5,028,949	4,265,371	5,009,181	4,268,987
Exhaust O2	% vol		14.62%	14.84%	14.80%	15.03%	14.74%	14.98%	14.75%	14.99%
Exhaust CO2	% vol		2.92%	2.81%	2.73%	2.63%	2.66%	2.55%	2.61%	2.50%
Exhaust H2O	% vol		5.73%	5.53%	6.47%	6.26%	7.40%	7.18%	7.74%	7.51%
Exhaust N2	% vol		75.81%	75.90%	75.10%	75.18%	74.33%	74.41%	74.02%	74.11%
Exhaust Ar	% vol		0.91%	0.91%	0.89%	0.90%	0.88%	0.88%	0.87%	0.89%

CASE IDENTIFICATION										
Parameter	**Units**	**Comments**	**ULSD1**	**ULSD2**	**ULSD3**	**ULSD4**	**ULSD5**	**ULSD6**	**ULSD7**	**ULSD8**
Ambient dry bulb	^oF		3	3	59	59	75	75	94	94
Ambient wet bulb	^oF		1	1	52	52	69	69	76	76
CTG load	%		100%	75%	100%	75%	100%	75%	100%	75%
Evap cooler efficiency	%		0%	0%	85%	0%	85%	0%	85%	0%
Fuel			ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD	ULSD
STACK SUMMARY										
Stack flow	ACFM		2,887,241	2,401,194	2,859,065	2,416,197	2,830,556	2,382,252	2,820,266	2,401,455
Stack flow	pph		5,289,348	4,405,503	5,223,269	4,423,445	5,156,644	4,348,944	5,132,853	4,381,855
Stack velocity	ft/sec		106.4	88.5	105.3	89.0	104.3	87.8	103.9	88.5
Stack Mole Wt.	lb/lb-mole		28.50	28.55	28.43	28.49	28.35	28.40	28.32	28.39
Stack temp	^oF	w/ heat loss	820	820	820	820	820	820	820	820
CTG heat consumption	MMBtu/h	HHV	2,101	1,694	1,955	1,586	1,877	1,518	1,831	1,487
CTG NOx	pph	As NO2	352.0	281.0	328.0	263.0	315.0	252.0	307.0	247.0
Stack NOx	ppmvd	@15%O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Stack NOx	pph	As NO2	123.0	99.0	114.0	93.0	110.0	89.0	107.0	87.0
Stack NOx-method 19	lb/MMBtu HHV	as NO2	0.058	0.058	0.058	0.058	0.058	0.058	0.058	0.058
Stack CO	ppmvd	@15% O2	16.00	16.00	16.00	16.00	16.00	16.00	16.00	16.00
Stack CO	pph		80.0	65.0	75.0	61.0	72.0	58.0	70.0	57.0
Stack CO-method 19	lb/MMBtu HHV		0.038	0.038	0.038	0.038	0.038	0.038	0.038	0.038
Stack VOC	ppmvw	@15% O2	3.90	3.90	3.90	3.90	3.90	3.90	3.90	3.90
Stack VOC-actual	pph	NMTHC	12.50	10.10	11.60	9.50	11.20	9.10	10.90	8.90
Stack VOC-method 19	lb/MMBtu HHV	NMTHC as CH4	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059	0.0059
SO2 emission	pph		3.24	2.61	3.02	2.45	2.90	2.34	2.83	2.29
Stack SO2-method 19	lb/MMBtu HHV		0.0014	0.0015	0.0014	0.0015	0.0014	0.0015	0.0014	0.0015
H2SO4 @stack	pph		0.58	0.47	0.54	0.44	0.52	0.42	0.51	0.41
H2SO4-method 19	lb/MMBtu HHV		0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
NH3	pph		18.7	14.9	17.4	14.0	16.7	13.4	16.3	13.1
NH3	ppmvd	@15%O2	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
PM10	pph		34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
PM10 - method 19	lb/MMBtu HHV		0.0162	0.0201	0.0174	0.0214	0.0181	0.0224	0.0186	0.0229
CTG INPUTS (PER CTG)										
CTG fuel LHV	Btu/lb		18,300	18,300	18,300	18,300	18,300	18,300	18,300	18,300
Relative humidity	%		42.40%	42.40%	62.70%	62.70%	74.30%	74.30%	44.30%	44.30%
Injection ratio	lb H2O/lb fuel		1.371	1.284	1.341	1.251	1.273	1.165	1.236	1.166
CTG gross power	kW		196,700	147,500	181,600	136,200	172,700	129,500	167,500	125,600
CTG gross ht rate	Btu/kWh LHV		10050	10810	10130	10960	10230	11030	10290	11140
Exhaust flow	pph		5,288,978	4,405,208	5,222,924	4,423,169	5,156,313	4,348,679	5,132,530	4,381,596
Exhaust O2	% vol		13.35%	13.70%	13.60%	14.03%	13.64%	14.05%	13.71%	14.19%
Exhaust CO2	% vol		4.34%	4.17%	4.08%	3.88%	3.96%	3.77%	3.88%	3.66%
Exhaust H2O	% vol		8.37%	7.81%	8.85%	8.11%	9.46%	8.73%	9.63%	8.75%
Exhaust N2	% vol		73.07%	73.45%	72.59%	73.10%	72.08%	72.58%	71.92%	72.53%
Exhaust Ar	% vol		0.87%	0.87%	0.88%	0.88%	0.86%	0.86%	0.86%	0.86%

SIEMENS SGT-5000F POTENTIAL EMISSIONS						
	Gas (lb/hr @ 59F)		Oil (lb/hr @ 3F)	Baseload PTE (tpy)	SUSD Net Increase (tpy)	Facility PTE (tpy)
Pollutant	**100%**	**75%**	**100%**			
NOx	23.0	18.0	125.0	98.3	10.4	108.7
CO	21.0	17.0	61.0	68.5	262.1	330.6
PM	12.0	12.0	60.0	49.2	0	49.2
SO2	2.32	1.83	3.27	6.18	0	6.2
VOC	2.90	2.30	15.00	12.1	12.4	24.7
NH3	16.4	12.9	18.4	41.7	0	41.7
H2SO4	0.31	0.25	0.44	0.8	0	0.8

Maximum Hours Per Year	2500	per CTG
Maximum Hours On Oil	400	per CTG
Number Of Starts Per Year	200	per CTG
Startup/Shutdown Hours Per Year	219	per CTG

VOC emissions include 0.2 tpy from fuel oil storage tank

Siemens SGT6-5000F Startup & Shutdown Emissions - Gas						
	Gas 59F	Startup/Shutdown Combined				PTE
	Baseload				Net Increase	Increase
Pollutant	(lbs/hr)	Duration (min)	(lbs)	(lbs/hr)	(lbs/hr)	(tpy)
NOx	23.00	66.0	70.6	64.1	41.1	3.8
CO	21.00	66.0	1,179.6	1,072.3	1051.3	98.3
VOC	2.90	66.0	48.0	43.6	40.7	3.81
Number of Gas Starts Per Year			170			
Startup/Shutdown Hours Per Year			187			

Siemens SGT6-5000F Startup & Shutdown Emissions - Oil						
	Oil 3F	Startup/Shutdown Combined				PTE
	Baseload				Net Increase	Increase
Pollutant	(lbs/hr)	Duration (min)	(lbs)	(lbs/hr)	(lbs/hr)	(tpy)
NOx	125.0	64.0	223.8	209.8	84.8	1.36
CO	61.0	64.0	2,247.5	2,107.0	2,046.0	32.74
VOC	15.00	64.0	176.0	165.0	150.0	2.40
Number of Oil Starts Per Year			30			
Oil Startup/Shutdown Hours Per Year			32			

Siemens SGT6-5000F Startup & Shutdown Emissions - Summary			
Pollutant	PTE Increase - Gas Starts (tpy)	PTE Increase - Oil Starts (tpy)	Total PTE Increase
NOx	3.8	1.4	5.2
CO	98.3	32.7	131.0
VOC	3.8	2.4	6.2
Total Number of Starts Per Year	200		
Number of Oil Starts Per Year	30		
Startup/Shutdown Hours Per Year	219		

Siemens SGT6-5000F	time	Emissions (lbs)		
	(min)	NOx	CO	VOC
startup on gas	45	52	598	29
shutdown on gas	21	18	581	19
startup on oil	44	115	1199	94
shutdown on oil	20	109	1049	82

CASE IDENTIFICATION			A	A	A	A	A	A	A	A
Parameter	**Units**	**Comments**	**NG1**	**NG2**	**NG3**	**NG4**	**NG5**	**NG6**	**NG7**	**NG8**
Ambient dry bulb	^{o}F		3	3	59	59	75	75	94	94
Ambient wet bulb	^{o}F		1	1	52	52	69	69	76	76
CTG load	%		100%	75%	100%	75%	100%	75%	100%	75%
Evap cooler efficiency	%		0%	0%	85%	85%	85%	85%	85%	85%
Fuel			Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas	Nat. Gas
STACK SUMMARY										
Stack flow	ACFM		3126112	2572505	3030173	2494342	2977782	2458530	2958962	2412591
Stack flow	pph		5743359	4728363	5548232	4572223	5431828	4489163	5389412	4403647
Stack velocity	ft/sec		115	95	112	92	110	91	109	89
Stack Mole wt.	lb/lb-mole		28.58	28.60	28.49	28.52	28.38	28.41	28.34	28.40
Stack temp	^{o}F	w/ heat loss	820	820	820	820	820	820	820	820
CTG heat consum	MMBtu/h	HHV	2,256.7	1,793.1	2,036.7	1,601.8	1,945.4	1,534.7	1,894.6	1,450.9
CTG Nox	pph	As NO2	76.0	60.4	68.6	54.0	65.6	51.7	63.8	48.9
Stack NOx	ppmvd	@15%O2	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Stack NOx	pph	As NO2	25.0	20.0	23.0	18.0	22.0	17.0	21.0	16.0
Stack NOx-method 19	lb/MMBtu HHV	as NO2	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111	0.0111
Stack CO	ppmvd	@15% O2	4.50	4.50	4.50	4.50	4.50	4.50	4.50	4.50
Stack CO	pph		23.0	19.0	21.0	17.0	20.0	16.0	20.0	15.0
Stack CO-method 19	lb/MMBtu HHV		0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101
Stack VOC	ppmvw	@15%O2	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Stack VOC	pph	NMTHC	3.20	2.60	2.90	2.30	2.80	2.20	2.70	2.10
Stack VOC-method 19	lb/MMBtu HHV	NMTHC as CH4	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014	0.0014
SO2 emission	pph		2.57	2.04	2.32	1.83	2.22	1.75	2.16	1.65
SO2-method 19	lb/MMBtu HHV		0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012	0.0012
H2SO4 @stack	pph		0.35	0.28	0.31	0.25	0.30	0.24	0.29	0.22
H2SO4-method 19	lb/MMBtu HHV		0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
NH3	pph		18.2	14.4	16.4	12.9	15.6	12.3	15.2	11.7
NH3	ppmvd	@15%O2	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
PM10	pph		12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
PM10 - method 19	lb/MMBtu HHV		0.0053	0.0067	0.0059	0.0075	0.0062	0.0078	0.0063	0.0083
CTG INPUTS (PER CTG)										
CTG fuel LHV	Btu/lb		20418	20418	20418	20418	20418	20418	20418	20418
Bar. Pressure	psia		14.691	14.691	14.691	14.691	14.691	14.691	14.691	14.691
Relative humidity	%		41.64%	41.64%	62.64%	62.64%	74.18%	74.18%	44.09%	44.09%
Injection ratio	lb wtr/lb fuel		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CTG gross power	kW		231,191	173,393	202,955	148,921	190,329	139,548	183,169	128,166
CTG gross ht rate	Btu/kWh LHV		8802	9325	9049	9699	9217	9917	9327	10208
Exhaust flow	pph		5,743,226	4,728,256	5,548,111	4,572,128	5,431,712	4,489,072	5,389,300	4,403,561
Exhaust O2	% vol		14.44%	14.67%	14.66%	14.96%	14.60%	14.89%	14.63%	15.05%
Exhaust CO2	% vol		3.00%	2.90%	2.80%	2.67%	2.72%	2.60%	2.66%	2.50%
Exhaust H2O	% vol		5.89%	5.69%	6.61%	6.21%	7.52%	7.16%	7.86%	7.18%
Exhaust N2	% vol		75.78%	75.85%	75.06%	75.27%	74.28%	74.47%	73.97%	74.39%
Exhaust Ar	% vol		0.89%	0.89%	0.88%	0.89%	0.87%	0.88%	0.87%	0.88%

CASE IDENTIFICATION			C	C	C	C
Parameter	**Units**	**Comments**	**ULSD1**	**ULSD3**	**ULSD5**	**ULSD7**
Ambient dry bulb	°F		3	59	75	94
Ambient wet bulb	°F		1	52	69	76
CTG load	%		100%	100%	100%	100%
Evap cooler efficiency	%		0%	85%	85%	85%
Fuel			ULSD	ULSD	ULSD	ULSD
STACK SUMMARY						
Stack flow	ACFM		3028957	2934899	2881880	2863379
Stack flow	pph		5613518	5417631	5298775	5255942
Stack velocity	ft/sec		112	108	106	105
Stack Mole wt.	lb/lb-mole		28.83	28.72	28.61	28.56
Stack temp	°F	w/ heat loss	820	820	820	820
CTG heat consum	MMBtu/h	HHV	2,138.1	1,927.1	1,839.9	1,791.2
CTG Nox	pph	As NO2	359.8	324.3	309.6	301.4
Stack NOx	ppmvd	@15%O2	15.0	15.0	15.0	15.0
Stack NOx	pph	As NO2	125.0	113.0	108.0	105.0
Stack NOx-method 19	lb/MMBtu HHV	as NO2	0.0583	0.0583	0.0583	0.0583
Stack CO	ppmvd	@15% O2	12.00	12.00	12.00	12.00
Stack CO	pph		61.0	61.0	61.0	61.0
Stack CO-method 19	lb/MMBtu HHV		0.0284	0.0284	0.0284	0.0284
Stack VOC	ppmvw	@15%O2	4.60	4.60	4.60	4.60
Stack VOC	pph	NMTHC	15.00	13.50	12.90	12.60
Stack VOC-method 19	lb/MMBtu HHV	NMTHC as CH4	0.0070	0.0070	0.0070	0.0070
SO2 emission	pph		3.27	2.95	2.82	2.74
SO2-method 19	lb/MMBtu HHV		0.0015	0.0015	0.0015	0.0015
H2SO4 @stack	pph		0.44	0.40	0.38	0.37
H2SO4-method 19	lb/MMBtu HHV		0.0002	0.0002	0.0002	0.0002
NH3	pph		18.4	16.6	15.8	15.4
NH3	ppmvd	@15%O2	6.00	6.00	6.00	6.00
PM10	pph		60.0	60.0	60.0	60.0
PM10 - method 19	lb/MMBtu HHV		0.0281	0.0311	0.0326	0.0335
CTG INPUTS (PER CTG)						
CTG fuel LHV	Btu/lb		18450	18450	18450	18450
Bar. Pressure	psia		14.691	14.691	14.691	14.691
Relative humidity	%		41.64%	62.64%	74.18%	44.09%
Injection ratio	lb wtr/lb fuel		0.400	0.400	0.400	0.400
CTG gross power	kW		222,414	194,657	182,286	175,283
CTG gross ht rate	Btu/kWh LHV		9047	9317	9499	9617
Exhaust flow	pph		5,613,127	5,417,279	5,298,439	5,255,614
Exhaust O2	% vol		14.37%	14.60%	14.54%	14.57%
Exhaust CO2	% vol		4.06%	3.78%	3.68%	3.60%
Exhaust H2O	% vol		5.05%	5.83%	6.76%	7.13%
Exhaust N2	% vol		75.62%	74.91%	74.14%	73.83%
Exhaust Ar	% vol		0.89%	0.88%	0.87%	0.87%

Bridgeport Peaking Station
Potential HAP Emissions

HAP	Natural Gas Emission Factor (lb/MMBtu)	Distillate Oil Emission Factor (lb/MMBtu)	GE 7FA 59F Gas Emission Rate (lb/hr)	GE 7FA Maximum ULSD Emission Rate (lb/hr)	GE 7FA Potential Emissions (tpy)	Siemens SGT6-5000F 59F Gas Emission Rate (lb/hr)	Siemens SGT6-5000F Maximum ULSD Emission Rate (lb/hr)	Siemens SGT6-5000F Potential Emissions (tpy)
1,3-Butadiene	4.30E-07	1.60E-05	7.74E-04	3.36E-02	1.84E-02	8.76E-04	3.42E-02	1.55E-02
Acetaldehyde	4.00E-05		7.20E-02		1.80E-01	8.15E-02		2.04E-01
Acrolein	6.40E-06		1.15E-02		2.88E-02	1.30E-02		3.26E-02
Benzene	1.20E-05	5.50E-05	2.16E-02	1.16E-01	1.01E-01	2.44E-02	1.18E-01	9.84E-02
Ethylbenzene	3.20E-05		5.76E-02		1.44E-01	6.52E-02		1.63E-01
Formaldehyde	7.10E-04	2.80E-04	1.28E+00	5.88E-01	3.20E+00	1.45E+00	5.99E-01	3.62E+00
Naphthalene	1.30E-06	3.50E-05	2.34E-03	7.35E-02	4.14E-02	2.65E-03	7.48E-02	3.55E-02
PAH	2.20E-06	9.62E-06	3.96E-03	2.02E-02	1.80E-02	4.48E-03	2.06E-02	1.76E-02
Propylene Oxid	2.90E-05		5.22E-02		1.31E-01	5.91E-02		1.48E-01
Toluene	1.30E-04		2.34E-01		5.85E-01	2.65E-01		6.62E-01
Xylenes	6.40E-05		1.15E-01		2.88E-01	1.30E-01		3.26E-01
Arsenic		1.96E-06		4.11E-03	2.06E-03		4.18E-03	1.67E-03
Beryllium		3.10E-07		6.51E-04	3.26E-04		6.63E-04	2.65E-04
Cadmium		4.80E-06		1.01E-02	5.04E-03		1.03E-02	4.11E-03
Chromium		1.10E-05		2.31E-02	1.16E-02		2.35E-02	9.41E-03
Lead		1.40E-05		2.94E-02	1.47E-02		2.99E-02	1.20E-02
Manganese		7.90E-04		1.66E+00	8.30E-01		1.69E+00	6.76E-01
Mercury		1.20E-06		2.52E-03	1.26E-03		2.57E-03	1.03E-03
Nickel		4.60E-06		9.66E-03	4.83E-03		9.84E-03	3.93E-03
Selenium		2.50E-05		5.25E-02	2.63E-02		5.35E-02	2.14E-02
TOTALS					**5.6**			**6.0**

NOTES:	Turbine potential annual emission rates based upon 500 hr/yr firing ULSD (400 hours for Siemens SGT6-5000) for those HAPS with a higher emission factor furing oil firing versus gas firing.
	Potential emissions for both turbine models is the total combined emissions for two turbines.
	The turbine HAP emission factors are from AP-42 Section 3.1 (April 2000),except for distillate oil emission factors for arsenic and PAH
	Distillate oil emission factors for arsenic and PAH are from CATEF database. Arsenic is max value and PAH is the sum of 11 components (mean val

HAP	Max Emission Rate g/s	Actual Stack Concentration ug/m3	HLV	MASC	MASC > actual?
1,3-Butadiene	4.31E-03	3.91	22000	1027865	yes
Acetaldehyde	1.03E-02	9.31	3600	168196	yes
Acrolein	1.64E-03	1.49	5	234	yes
Benzene	1.48E-02	13.44	150	7008	yes
Ethylbenzene	8.21E-03	7.45	8700	406474	yes
Formaldehyde	1.82E-01	165.22	12	561	yes
Naphthalene	9.43E-03	8.55	1000	46721	yes
PAH	2.59E-03	2.35	0.1	4.67	yes
Propylene Oxide	7.44E-03	6.75	1000	46721	yes
Toluene	3.34E-02	30.25	7500	350408	yes
Xylenes	1.64E-02	14.89	8680	405539	yes
Ammonia	2.3184	2102.34	360	16820	yes
Sulfuric Acid	7.31E-02	66.27	20	934	yes
Arsenic	5.27E-04	0.48	0.05	2.34	yes
Beryllium	8.35E-05	0.08	0.01	0.47	yes
Cadmium	1.29E-03	1.17	0.4	18.69	yes
Chromium	2.96E-03	2.69	0.5	23.36	yes
Lead	3.77E-03	3.42	3	140.16	yes
Manganese	2.13E-01	192.99	N/A		N/A
Mercury	3.23E-04	0.29	1	46.72	yes
Nickel	1.24E-03	1.12	5	233.61	yes
Selenium	6.74E-03	6.11	4	186.9	yes

Bridgeport Energy II, LLC
Economic Analysis For CO Oxidation Catalyst - GE 7FA Turbines

Turbine Output @ Average Annual Temp. (MW)	181.6	Total Hours	2,500	
Catalyst Volume (ft^3)	1820	Estimate		
CO Emissions (tpy)	117.6	PTE	*per turbine*	
Equipment Cost (EC)		(Factor)		
Catalytic Oxidizer			$750,000	*Estimate*
Instrumentation (10% of Oxidizer Equipment Costs)			$75,000	*OAQPS*
Taxes and Freight (5% of Oxidizer Equipment Costs)			$37,500	*OAQPS*
		Total Equipment Cost (TEC)	**$862,500**	
Direct Installation Costs				
Foundation		(TEC*0.08)	$69,000	*OAQPS*
Erection and Handling		(TEC*0.14)	$120,750	*OAQPS*
Electrical		(TEC*0.04)	$34,500	*OAQPS*
Piping		(TEC*0.02)	$17,250	*OAQPS*
Insulation		(TEC*0.01)	$8,625	*OAQPS*
Painting		(TEC*0.01)	$8,625	*OAQPS*
Inlet/Outlet Transitions and Vanes		Estimate	$50,000	
		Total Direct Installation Cost	**$308,750**	
Indirect Installation Costs				
Engineering and Supervision		(TEC*0.1)	$86,250	*OAQPS*
Construction and Field Expenses		(TEC*0.05)	$43,125	*OAQPS*
Construction Fee		(TEC*0.1)	$86,250	*OAQPS*
Start Up		(TEC*0.02)	$17,250	*OAQPS*
Performance Test		(TEC*0.01)	$8,625	*OAQPS*
Contingencies		(TEC*0.03)	$25,875	*OAQPS*
		Total Indirect Installation Cost	**$267,375**	
		Total Capital Investment (TCI)	**$1,438,625**	
Direct Annual Costs ($/yr)				
Operating Labor (negligible)			$0	
Supervisory Labor (15% of Operating Labor)			$0	
Maintenance Labor (3 shifts/day, 0.5 hr/shift, $30/hr)			$5,475	365 day/yr, 1 sh/day
Maintenance Materials (1.0 * Maintenance Labor)			$5,475	*OAQPS*
Catalyst Replacement (3 yrs @ 8% interest, CFR=0.388)			$218,267	
Catalyst Disposal ($15/$ft^3$*0.388)			$10,592	
Electricity (negligible)			$0	
Performance Loss (0.6 in. @ 0.2% per in. @ $.05/kWh)			$27,240	
Production Loss (negligible)			$0	
		Total Direct Annual Cost	**$267,049**	
Indirect Annual Costs ($/yr)				
Overhead (60% of Operating, Supervisory and Maintenance Labor)			$3,285	
Property Taxes, Insurance and Administration (0.04 x TCI)			$57,545	
Capital Recovery (0.14903 x [TCI - Catalyst Replacement/0.38803])			$130,569	
		Total Indirect Annual Cost	**$191,399**	
		Total Annual Cost	$458,448	
		CO Controlled (tons/yr)	62.5	*87.5% Baseload, 25% SUSD*
		Control Cost ($/ton CO)	**$7,333**	

Notes: Catalyst replacement cost based upon 75% of purchased equipment cost.
Other costs from OAQPS Control Cost Manual (USEPA 1990a)

Bridgeport Energy II, LLC
Economic Analysis For CO Oxidation Catalyst - Siemens SGT6-5000F Turbines

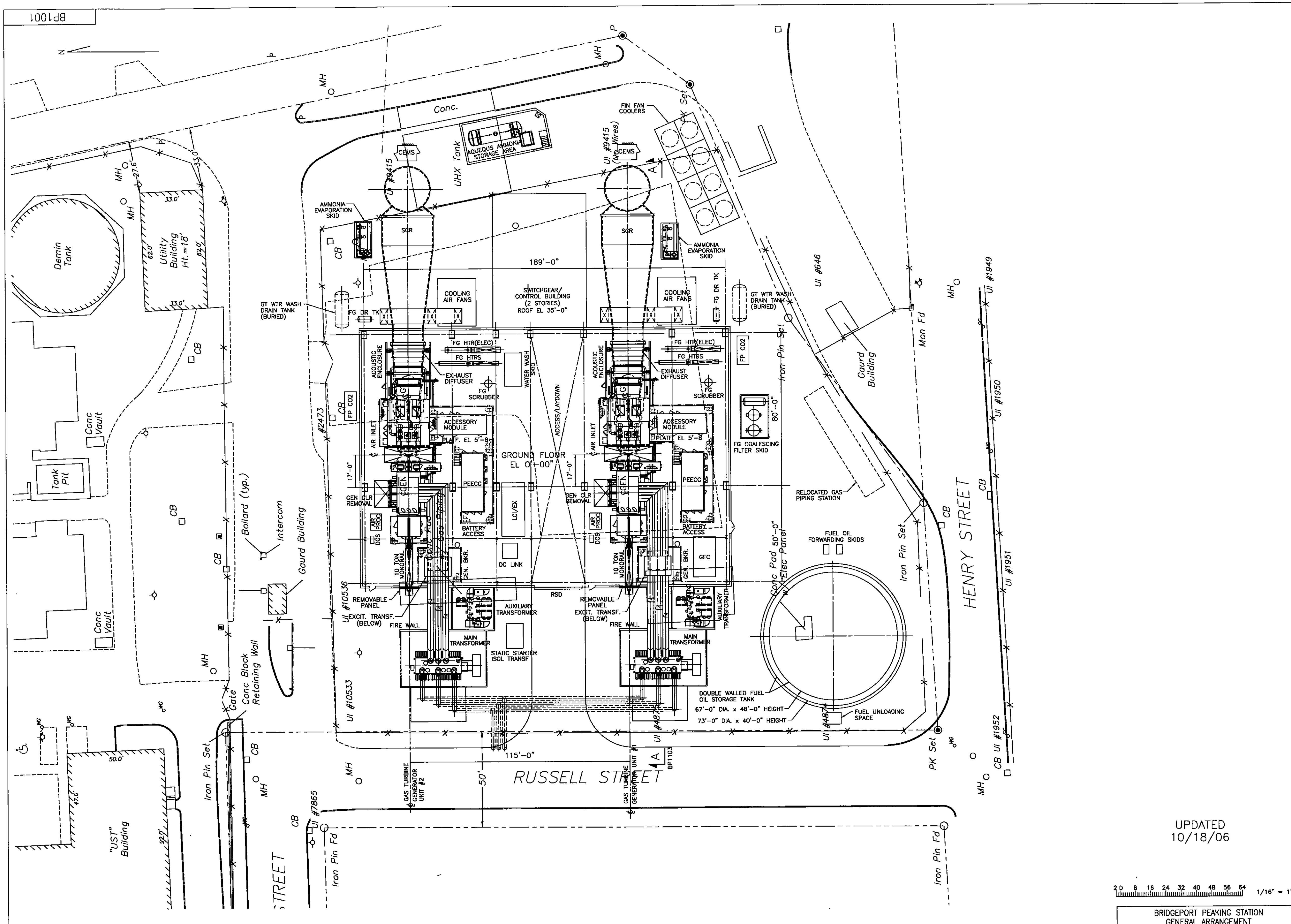
Turbine Output @ Average Annual Temp. (MW)	203.0	Total Hours	2,500	
Catalyst Volume (ft^3)	2034	Estimate		
CO Emissions (tpy)	165.3	PTE	*per turbine*	

Equipment Cost (EC)	(Factor)		
Catalytic Oxidizer		$750,000	*Estimate*
Instrumentation (10% of Oxidizer Equipment Costs)		$75,000	*OAQPS*
Taxes and Freight (5% of Oxidizer Equipment Costs)		$37,500	*OAQPS*
Total Equipment Cost (TEC)		**$862,500**	
Direct Installation Costs			
Foundation	(TEC*0.08)	$69,000	*OAQPS*
Erection and Handling	(TEC*0.14)	$120,750	*OAQPS*
Electrical	(TEC*0.04)	$34,500	*OAQPS*
Piping	(TEC*0.02)	$17,250	*OAQPS*
Insulation	(TEC*0.01)	$8,625	*OAQPS*
Painting	(TEC*0.01)	$8,625	*OAQPS*
Inlet/Outlet Transitions and Vanes	Estimate	$50,000	
Total Direct Installation Cost		**$308,750**	
Indirect Installation Costs			
Engineering and Supervision	(TEC*0.1)	$86,250	*OAQPS*
Construction and Field Expenses	(TEC*0.05)	$43,125	*OAQPS*
Construction Fee	(TEC*0.1)	$86,250	*OAQPS*
Start Up	(TEC*0.02)	$17,250	*OAQPS*
Performance Test	(TEC*0.01)	$8,625	*OAQPS*
Contingencies	(TEC*0.03)	$25,875	*OAQPS*
Total Indirect Installation Cost		**$267,375**	
Total Capital Investment (TCI)		**$1,438,625**	
Direct Annual Costs ($/yr)			
Operating Labor (negligible)		$0	
Supervisory Labor (15% of Operating Labor)		$0	
Maintenance Labor (3 shifts/day, 0.5 hr/shift, $30/hr)		$5,475	365 day/yr, 1 sh/day
Maintenance Materials (1.0 * Maintenance Labor)		$5,475	*OAQPS*
Catalyst Replacement (3 yrs @ 8% interest, CFR=0.388)		$218,267	
Catalyst Disposal ($15/ft^3*0.388)		$11,838	
Electricity (negligible)		$0	
Performance Loss (0.6 in. @ 0.2% per in. @ $.05/kWh)		$30,443	
Production Loss (negligible)		$0	
Total Direct Annual Cost		**$271,498**	
Indirect Annual Costs ($/yr)			
Overhead (60% of Operating, Supervisory and Maintenance Labor)		$3,285	
Property Taxes, Insurance and Administration (0.04 x TCI)		$57,545	
Capital Recovery (0.14903 x [TCI - Catalyst Replacement/0.38803])		$130,569	
Total Indirect Annual Cost		**$191,399**	
Total Annual Cost		$462,897	
CO Controlled (tons/yr)		59.4	*77.8% Baseload, 25% SUSD*
Control Cost ($/ton CO)		**$7,794**	

Notes: Catalyst replacement cost based upon 75% of purchased equipment cost.
Other costs from OAQPS Control Cost Manual (USEPA 1990a)

Appendix C

Preliminary Site Plan and Elevation Drawing



INTERDISCIPLINE REVIEW RECORD					
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE
ARCH.			MECHANICAL		
CIVIL			NUCLEAR		
ELECTRICAL			PIPING		
ENVIRON.			PROCESS		
GEN. ARRANG.			QA / QC		
HVAC			STRUCTURAL		
I & C					

REV NO	DATE	REVISIONS	BY	CHKR

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY				
APPROVED FOR CONSTRUCTION				

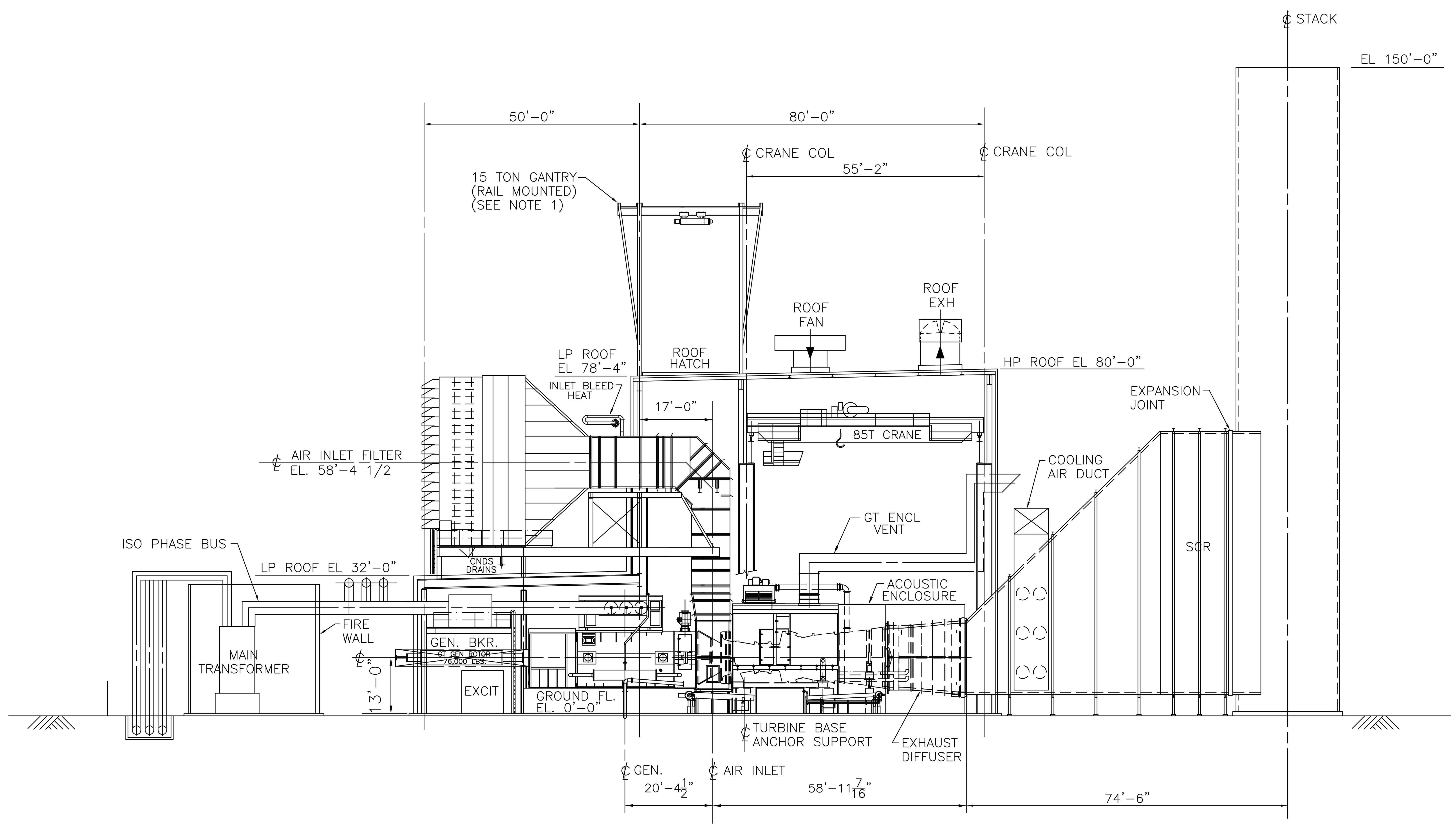
NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED & DATED. DESTROY ALL PRINTS BEARING EARLIER DATE &/OR REV.NO.

PROJECT NO.: 28823-001
DRAWN: W. NG DATE:
CHECKED: DATE:
SCALE: 1/16"=1'-0"

BRIDGEPORT PEAKING STATION
GENERAL ARRANGEMENT
PLOT PLAN (7FA)

Washington Group International
510 CARNEGIE CTR. – PRINCETON, NJ 08543 – (609)720-2000

DWG. NO. BP1001 REV A



SECTION A–A

NOTE:

1. GANTRY CRANE IS SHOWN IN THE INSTALLED POSITION. GANTRY WILL BE LOWERED TO COMPLY WITH HEIGHT RESTRICTION WHEN NOT IN USE.

UPDATED
12/15/06

10 8 16 24 32 40FT 3/32"=1'-0

INTERDISCIPLINE REVIEW RECORD						REV				REVISIONS	BY	CHKR
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE		REV NO	DATE				
ARCH.			MECHANICAL									
CIVIL			NUCLEAR									
ELECTRICAL			PIPING									
ENVIRON.			PROCESS									
GEN. ARRANG.			QA / QC									
HVAC			STRUCTURAL									
I & C												

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY				
APPROVED FOR CONSTRUCTION				
NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED & DATED. DESTROY ALL PRINTS BEARING EARLIER DATE &/OR REV.NO.				

PROJECT NO.: 28823-001
DRAWN: W. NG DATE:
CHECKED: DATE:
SCALE: 3/32"=1'-0"

BRIDGEPORT HARBOR PROJECT
GENERAL ARRANGEMENT
SECTION

Washington Group International
510 CARNEGIE CTR. – PRINCETON, NJ 08543 – (609)720-2000

DWG. NO. BP1103 REV A

BP1103