Major Comprehensive Plan Approval/Nonattainment New Source Review Permit Application

Canal Unit 3

Canal Generating Station
Sandwich, MA

Updated through Supplement No. 2

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ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	Definition
%	percent
°F	degrees Fahrenheit
AAL	Allowable Ambient Limit
AGT	Algonquin Gas Transmission, LLC
AIHA	American Industrial Hygiene Association
amsl	above mean sea level
ARM	Ambient Ratio Method
BACT	Best Available Control Technology
BANCT	Best Available Noise Control Technology
bhp	brake horsepower
Btu/kW-hr	British thermal units per kilowatt-hour
CAIR	Clean Air Interstate Rule
CCS	carbon capture and sequestration
CEMS	continuous emissions monitoring system
CF	capacity factor
CFR	Code of Federal Regulations
CH_4	methane
CI	compression ignition
CMR	Code of Massachusetts Regulations
CO	carbon monoxide
CO_2	carbon dioxide
CO_{2e}	carbon dioxide equivalents
CPA	Comprehensive Plan Approval
CSAPR	Cross-State Air Pollution Rule
CTG	combustion turbine generator
dB	decibels
dBA	A-weighted decibels
DLN	dry-low-NO_x
DPF	diesel particulate filter
EAB	Environmental Appeals Board
EEA	Massachusetts Executive Office of Energy and Environmental Affairs
EFSB	Massachusetts Energy Facilities Siting Board
EJ	***Environmental Justice***

Acronyms/Abbreviations	Definition
EPRG	Emergency Response Planning Guideline Levels
FCA	***Forward Capacity Auction***
FCM	***Forward Capacity Market***
FERC	***Federal Energy Regulatory Commission***
FLM	Federal Land Manager
g/hp-hr	grams per horsepower-hour
g/kW-hr	grams per kilowatt-hour
GE	General Electric
GEP	Good Engineering Practice
GHG	greenhouse gases
gr/100 scf	grains per 100 standard cubic feet
H_2	hydrogen
H_2O	water
H_2SO_4	sulfuric acid
HAPs	hazardous air pollutants
HHV	higher heating value
hp	horsepower
Hz	hertz
ISO	International Organization for Standardization
ISO-NE	Independent System Operator – New England
km	kilometer
kW	kilowatts
kWe	kilowatts (electrical)
L_{90}	residual noise level
LAER	Lowest Achievable Emission Rate
lb CO_2/MW-hr	pounds of carbon dioxide per megawatt-hour
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
lb/MW-hr	pounds per megawatt-hour
lbs	pounds
L_{eq}	equivalent noise level
LNG	liquefied natural gas
MAAQS	Massachusetts Ambient Air Quality Standards
MACT	Maximum Achievable Control Technology
MassDEP	Massachusetts Department of Environmental Protection

Acronyms/Abbreviations	Definition
MassDOT	***Massachusetts Department of Transportation***
MCPA	Major Comprehensive Plan Approval
MECL	***Minimum Emissions Compliance Load***
MMBtu/hr	million British thermal units per hour
MRCSP	Midwest Regional Carbon Sequestration Partnership
MW	megawatt
MW-hr	megawatt-hour
N_2	nitrogen
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAD	North American Datum
NED	National Elevation Data
NESHAPs	National Emissions Standards for Hazardous Air Pollutants
ng/J	nanograms per Joule
NH_3	ammonia
NLCD92	United States Geological Survey National Land Cover Data 1992
NMHC	non-methane hydrocarbons
NNSR	Nonattainment New Source Review
NO	nitrogen oxide
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NRG	NRG Canal LLC
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	oxygen
O_3	ozone
OTR	Ozone Transport Region
Pb	lead
PM	particulate matter
PM_{10}	particulate matter with a diameter equal to or less than 10 microns
ppmvdc	parts per million by volume, dry basis, corrected to 15% O_2
ppmw	parts per million by weight
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
PTE	potential to emit

Acronyms/Abbreviations	Definition
PWL	sound power level
Q/D	emissions/distance
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
RGGI	Regional Greenhouse Gas Initiative
ROW	***Right-of-Way***
SCR	selective catalytic reduction
SEMA/RI	***Southeast Massachusetts/Rhode Island***
SENA	***Southeastern New Englnad***
SER	Significant Emission Rate
SF_6	sulfur hexafluoride
SIA	Significant Impact Area
SIL	Significant Impact Level
SIP	State Implementation Plan
SMC	Significant Monitoring Concentration
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_4	sulfate
STC	sound transmission loss
SUSD	startup and shutdown
TEL	Threshold Effects Exposure Limit
the Court	United States Court of Appeals for the District of Columbia Circuit
the Guidance	USEPA's Guidance for $PM_{2.5}$ Permit Modeling
the Project	proposed installation of a simple-cycle combustion turbine at Canal Generating Station
the Station	Canal Generating Station
TMNSR	Ten-Minute Non-Spinning Reserve
tpy	tons per year
ULSD	ultra-low sulfur distillate
USACE	***United States Army Corps of Engineers***
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
AP-42	Compilation of Air Pollutant Emission Factors

Acronyms/Abbreviations	Definition
$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
Canal 3	NRG Canal 3 Development LLC

1.0 INTRODUCTION

NRG Canal 3 Development LLC (Canal 3) is proposing to construct a new, highly efficient, fast-starting, approximately 350-megawatt (MW)[1] peak electric generating unit (the Project) at the existing Canal Generating Station (the Station) located at 9 Freezer Road in Sandwich Massachusetts. The proposed new unit for the Project will consist of a simple-cycle combustion turbine fired with natural gas as the primary fuel, with limited firing of ultra-low sulfur distillate (ULSD) as the backup fuel. The combustion turbine generator (CTG) will operate no more than 4,380 hours per year, with ULSD firing limited to 720 hours per year.

NRG Canal LLC (NRG) operates the existing Station, which consists of two steam-electric generating units, each with a nominal generating capacity of 560 MW. Units 1 and 2 were originally constructed to fire No. 6 fuel oil as the sole fuel; Unit 2 was modified in 1996 to allow firing of either No. 6 fuel oil or natural gas. The Station also includes ancillary emission sources including two auxiliary boilers capable of firing natural gas or distillate oil, an emergency diesel-fired generator engine, a fuel-gas heater and other minor emission sources. The Station is an existing major source for emissions of nitrogen oxides (NO_x), volatile organic compounds (VOC), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with a diameter equal to or less than 10 microns (PM_{10}), particulate matter with a diameter equal to or less than 2.5 microns ($PM_{2.5}$); and Hazardous Air Pollutants (HAPs).

Air emissions from the proposed Project will consist primarily of products of combustion from the CTG. Barnstable County is designated as attainment with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants with the exception of ozone (O_3); Barnstable County is a moderate nonattainment area for the 1997 O_3 standard. The Project is subject to Major Comprehensive Plan Approval (MCPA) pursuant to 310 Code of Massachusetts Regulations (CMR) 7.02(5). In accordance with the Massachusetts Department of Environmental Protection's (MassDEP's) Nonattainment New Source Review (NNSR) permitting program (310 CMR 7.00, Appendix A (Appendix A), the Project is also subject to NNSR for emissions of NO_x.

Canal 3 is hereby applying for a MCPA, including NNSR, as required pursuant to 310 CMR 7.02 and Appendix A.

Based upon the potential to emit (PTE) estimates provided in Section 2, pursuant to 40 Code of Federal Regulations (CFR) 52.21 and the Prevention of Significant Deterioration (PSD) Delegation Agreement between United States Environmental Protection Agency (USEPA) and MassDEP, the Project is also subject to federal PSD review for emissions of NO_x, PM, PM_{10}, $PM_{2.5}$, greenhouse gases (GHG) and sulfuric acid (H_2SO_4). The PSD Permit Application is being provided as a separate document.

1.1 REGULATORY OVERVIEW

The Project is subject to MCPA and will also trigger NNSR review for NO_x. To satisfy NNSR and MCPA requirements, the Project will employ Lowest Achievable Emission Rate (LAER) controls for NO_x and Best Available Control Technology (BACT) emissions controls for all MassDEP-regulated pollutants, as required pursuant to 310 CMR 7.02(5). The LAER and BACT NO_x emission controls for the CTG will include dry-low-NO_x (DLN) burners and selective catalytic reduction (SCR) to control NO_x emissions; water (H_2O) injection will also be used when firing ULSD. Emissions of CO and VOC from the CTG will be controlled with good combustion practices and an oxidation catalyst system. ***Good combustion practices, or good combustion controls, as referred to throughout this document, refers to maintaining the appropriate air to fuel mixtures, air/fuel contact and combustion residence times to achieve proper combustion in accordance with the manufacturer's combustor design. This includes limiting residual emissions of CO and VOC while also limiting NOx formation in accordance with the combustor design.*** Emissions of PM_{10}, $PM_{2.5}$, SO_2, and H_2SO_4 will be controlled by the use of low sulfur fuels with natural gas as the primary fuel for the CTG. GHG emissions will be minimized by the use of a high-

[1] The gross electrical output of the CTG will vary from approximately 330 MW at higher ambient temperatures to approximately 365 MW at very low temperatures.

efficiency simple-cycle combustion turbine fired with natural gas as the primary fuel, with limited firing of ULSD as the backup fuel. The Project will comply with the National Ambient Air Quality Standards (NAAQS), Massachusetts Ambient Air Quality Standards (MAAQS), Massachusetts Ambient Air Toxics Guidelines and all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs).

1.2 APPLICATION OVERVIEW

1.2.1 Application Organization

This MCPA/NNSR application is divided into eight sections. Section 1 provides an overview of the Project and regulatory requirements. Section 2 provides a detailed description of the proposed Project, including estimated emissions. Section 3 provides a detailed review of applicable MCPA requirements. Section 4 provides the MCPA LAER control technology evaluation. Section 5 provides the MCPA BACT control technology evaluation. An air quality modeling analyses demonstrating compliance with NAAQS and other modeling requirements is provided as Section 6. Section 7 provides the noise impact analysis, and Section 8 provides references.

The completed MassDEP air permit application forms are provided in Appendix A. Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix B. Appendix C provides the NNSR Alternatives analysis. Appendix D presents summary tables supporting the LAER/BACT analyses. Appendix E provides vendor data for the primary emission sources. Appendix F provides the Energy Facilities Siting Board (EFSB) Testimony of Daniel Peaco, which is referenced in Appendix C.

1.2.2 Application Contacts

To facilitate agency review of this application, individuals familiar with the Project and this application are identified below.

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2.0 PROJECT DESCRIPTION

2.1 PROJECT SUMMARY

The Project site is located on an approximately 12-acre site (Project site) within the larger Station property (Property) in Sandwich, Barnstable County, Massachusetts (Figure 2-1). The Project plans to use a General Electric (GE) 7HA.02 combustion turbine, or a comparable unit, operating in simple-cycle mode to provide electric power during periods of peak demand. The CTG generating system will primarily include: one GE 7HA.02 CTG, or a comparable turbine; an evaporative inlet air cooler; an SCR system with an ammonia (NH_3) injection skid; an oxidation catalyst system; tempering air fans; an exhaust stack; a two-winding main generator step-up transformer; an auxiliary transformer; and electrical switchgear. The Project will also include two ancillary emission sources, a 500-kilowatt (electrical) (kWe) emergency diesel generator engine (581-kW [mechanical]), and a 135-brake-horsepower (bhp) emergency diesel fire pump engine.

Natural gas for the Project will be delivered via the existing Algonquin Gas Transmission, LLC (AGT) lateral that currently serves the existing Station. A new 3,590-foot on-site natural gas pipeline will be constructed from the existing natural gas pipeline on the Property to the new gas compressor building. ULSD for the Project will be stored in an existing 5,700,000-gallon aboveground storage tank and associated 1,800,000-gallon day tank; both tanks currently hold No. 6 fuel oil and will be converted to hold ULSD prior to operation of the Project. Two existing fully diked aqueous NH_3 storage tanks, each with a capacity of 60,000 gallons will provide aqueous NH_3 for the SCR system.

The proposed Project is intended to operate primarily during periods of peak demand providing additional needed electric generating capacity to ISO New England's Southeast Massachusetts/Rhode Island (SEMA/RI)[2] load zone. ISO-NE ensures sufficient electric generating capacity throughout the region by administering a Forward Capacity Market (FCM). The FCM includes an annual Forward Capacity Auction (FCA) in which suppliers compete for the opportunity to provide capacity to meet forecasted demand three years in the future. Qualified suppliers with the lowest price offers "clear" the auction and qualify for potential capacity payments. In February 2015, the results of FCA9 demonstrated a shortfall of 238 MW of generation capacity in the SEMA/RI load zone. In response to this shortfall, the Project decided to participate in FCA10 (held on February 8, 2016) and cleared the market with a capacity supply obligation starting on June 1, 2019.

Suppliers that clear in a Forward Capacity Auction undertake an obligation to produce power whenever called upon by ISO-NE. In 2015, ISO-NE added a Pay-for-Performance requirement to the Forward Capacity Market to address recent winter reliability issues experienced when natural gas supplies to the region were curtailed. Under this new Pay-for-Performance design, capacity resources that are unable to fully respond within 30 minutes of a dispatch order suffer financial penalties in the Forward Capacity Market. Pay-for-performance penalties to generators can actually exceed their total revenues from the capacity market and therefore serve as a significant incentive for these resources to be fully available throughout the year. As a result, to be economically viable generating resources relying on natural gas pipelines with a history of winter curtailments must also have a reliable backup fuel supply.

The Project will receive natural gas from the Algonquin Gas Transmission (AGT) lateral serving Cape Cod. While there is normally sufficient capacity on this system to serve the Project at full load, there are times (such as during severe cold snaps) when natural gas supplies are insufficient to meet Project needs without disrupting service to downstream commercial and residential customers. As described in Section 5.2.1,

[2] On November 10, 2015, ISO-NE made a filing at the FERC with specific information related to FCA #10. Within that filing, they confirmed that only two capacity zones will be modeled in FCA #10: Southeastern New England (SENE) and Rest of Pool (ROP). SENE is a new capacity zone that includes two zones previously known as SEMA/RI and Northeast Massachusetts (NEMA).

during these times the Project will operate on its backup fuel supply (ULSD) until normal conditions are restored on the pipeline.

In addition, the Project may elect to participate as a Fast Start Generator in ISO New England's Forward Reserve Market. This market ensures that the electric grid has enough quick start capacity to respond to the largest single contingency on the system (e.g., the instantaneous loss of a major transmission line or on-line generating facility). When operating in the reserve market, the Project would have to start up and reach full load within as little as 10 minutes of receiving a dispatch signal from ISO- NE. Since the AGT G lateral does not currently have the ability to provide sufficient No Notice fuel without disrupting service to downstream customers, the Project would also have to start up on its backup ULSD fuel supply in this circumstance as well.

2.2 SITE DESCRIPTION

NRG Canal owns two non-contiguous tracts of land, which total approximately 88 acres. The Station Property consists of a 52-acre tract north of a railroad ROW, owned by MassDOT and operated by Cape Cod Central Railroad. The proposed nominal 350 MW CTG will be located on approximately 12 acres on the eastern portion of this 52-acre Station Property. A separate 36-acre tract southern area is located to the south of the railroad ROW. The majority of the existing Canal Generating Station is located on the 52-acre Station Property, Major components associated with existing Canal Station include: two steam-electric generating units; a 498-foot exhaust stack; eight aboveground storage tanks; two NH_3 storage tanks; and appurtenant structures and infrastructure. Two aboveground oil storage tanks are located on the 36-acre tract south of the railroad ROW. Natural gas service is provided by an existing Algonquin Gas Transmission (AGT) pipeline, which is located under the Cape Cod Canal and is accessed at the western end of the 52-acre Station property.

Directly north of the 52-acre Station Property is the Cape Cod Canal, which has recreational walkways/bike paths located directly next to and on each side of the Canal. Canal Station has a docking facility located on the south side of the Canal for the docking of vessels, including oil delivery barges. The area directly north of the Canal, across from Canal Station, is primarily undeveloped. Scusset Beach State Reservation, which includes a campground and beach on Cape Cod Bay, is located to the northeast of the Project site, north of the Canal. On the South side of the Canal, the Town of Sandwich Marina, the Cape Cod Canal Visitors Center, and the USACE Sandcatcher Recreation Area are located to the east of the Project site. Farther east is an area of mixed use development. Several seasonal restaurants, including the Pilot House Restaurant and Lounge, Joe's Lobster Market, and Seafood Sam's Restaurant are located to the east of the Project site, on the south of the Cape Cod Canal, along with the Global Companies LLC fuel oil tank farm, and a United States Coast Guard Station. A more densely developed residential area is located farther east, extending to Scusset Harbor.

Immediately south of the Station Property is an active railroad ROW, used by the Cape Cod Scenic Railroad and a small number of freight trains. The nearest residence to the Station Property is located on Freezer Road, adjacent to and just south of the railroad tracks. Two additional single-family homes are located on Briarwood Avenue, south of the Station Property. Eversource owns an electrical substation, located south of the railroad ROW. Undeveloped wooded areas south of the Station Property extend to Tupper Road. To the east of Freezer Road, north of Tupper Road, are The Shipwreck Ice Cream and Marylou's Coffee.

South of Tupper Road, commercial development extends to Old King's Highway (Route 6A). This area includes a Super Stop & Shop, CVS Pharmacy, Citizen's Bank, Eastern Bank, Bobby Byrnes Restaurant, Cafe Chew, and the Post Office. Farther south, across Old King's Highway, is a mix of commercial and residential uses. Shawme-Crowell State Forest is approximately 1 mile south of the Station Property.

West of the Station Property is undeveloped wooded land in the Town of Bourne. Farther west is a mix of commercial and residential land uses along Old King's Highway.

The Massachusetts Executive Office of Energy and Environmental Affairs (EEA) has developed an Environmental Justice (EJ) Policy, and has identified EJ neighborhoods as areas with annual median household income equal to or less than 65% of the statewide median or populations 25% or greater of individuals classified as minority, foreign born, or lacking English language proficiency. The purpose of an EJ analysis is to determine whether the construction or operation of a proposed facility would have a significant adverse and disproportionate burden on an Environmental Justice community. Based on the determination of EJ areas as done by EEA, there are no mapped Environmental Justice communities within 5 miles of the Canal Generating Station. The closest EEA-mapped EJ area is to the west, in Onset MA, approximately 7.5 miles from the Project site.

2.3 SIMPLE-CYCLE COMBUSTION TURBINE

The Project will utilize a GE 7HA.02 CTG, or comparable unit. The CTG will operate in simple-cycle mode where the thermal energy from combustion of fuel is converted to mechanical energy, which drives an integral compressor and electric generator; there is no supplementary waste heat recovery. Simple-cycle operation allows for the CTG to respond quickly to the needs of the ISO-NE regional transmission system during times of peak energy demand. The reasons for selection of the H-Class turbine over a combined-cycle unit or an alternative simple-cycle turbine are also addressed in Section 5.2.7.

2.3.1 Combustion Turbine Operation

The CTG is composed of three major sections: the compressor, the combustor, and the power turbine, as described below:

- In the compressor section, ambient air is drawn through a filter (which under certain meteorological and unit load conditions includes the operation of an evaporative cooler or inlet air heater) to clean (and cool or heat) the air. The air is then compressed and directed to the combustor section.
- The primary fuel that will be utilized by the CTG is natural gas, with limited firing of ULSD as a back-up fuel. The CTG will utilize DLN combustors to control NO_x formation during natural gas firing by pre-mixing fuel and air immediately prior to combustion. During ULSD firing, H_2O will be emulsified with the fuel and injected into the combustor to minimize peak flame temperature and reduce NO_x formation.
- In the combustor section, the fuel (gas) or fuel/ H_2O mixture (ULSD) is introduced to air and combusted. Hot gases from combustion are diluted with additional air from the compressor section and directed to the power turbine section at high temperature and pressure.
- In the power turbine section, the hot exhaust gases expand and rotate the turbine blades, which are coupled to a shaft. The rotating shaft drives the compressor and the generator, which generates electricity.

Figure 2-2 presents the Site Plan and General Arrangement, Figure 2-3 presents an Elevation View, and Figure 2-4 presents a Process Flow Diagram.

The electrical output of the CTG varies with temperature. At lower temperatures, the density of the combustion air is higher and more mass can be injected into the combustor, which results in higher electrical output from the power turbine. In warm weather when air density is lower, an evaporative cooler is utilized to cool the combustion air in order to achieve greater electrical output. The gross electrical output of the CTG will vary from approximately 330 MW at higher ambient temperatures to approximately 365 MW at very low ambient temperatures. The net electrical output of the CTG will be slightly less due to internal (plant) loads from auxiliary equipment associated with the Project. The CTG will have a heat input rate while firing natural gas of approximately 3,256 million British thermal units per hour (MMBtu/hr) (higher heating value [HHV]) at 100 percent (%) load, 59 degrees Fahrenheit (°F) and

60% relative humidity. At the same conditions while firing ULSD, the CTG will have a firing rate of approximately 3,303 MMBtu/hr (HHV).

After passing through the combustion turbine, the hot exhaust gases will be sent through an oxidation catalyst and SCR to control NO_x, CO and VOC emissions. The temperature of the exhaust at the control equipment will be approximately 900°F. The exhaust stack will be constructed of steel and is proposed to be 220 feet tall, with a 25-foot diameter. With the base of the exhaust stack proposed at 16 feet above mean sea level (amsl), the top of the stack is proposed at an elevation of 236 feet amsl.

2.3.2 Air Pollution Control Equipment

The emission control technologies proposed for the CTG include DLN combustors and SCR to control NO_x emissions, and an oxidation catalyst to control CO and VOC emissions. When firing ULSD, H_2O injection will also be used to minimize NO_x emissions upstream of the SCR. DLN combustors are integrated within the CTG; the SCR and oxidation catalyst will be located within an integral separate housing. Due to the elevated temperature of the exhaust gas from the CTG (>1,100°F), a tempering air system will be employed to inject ambient air into the exhaust gas and lower its temperature to the proper operating temperature (nominally 900°F) at the SCR and oxidation catalyst.

The DLN combustors control NO_x formation during natural gas firing by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NO_x formation by minimizing both the flame temperature and the concentration of oxygen (O_2) at the flame front. During ULSD firing, H_2O will be emulsified with the fuel and injected into the combustor, effectively mixing with the combustion air. By injecting H_2O into the combustion zone, the peak flame temperature will be minimized resulting in lower thermal NO_x formation.

CO and VOC formation will be minimized by combustor design and good combustion practices to ensure complete combustion of the fuel. Emissions of SO_2, $PM/PM_{10}/PM_{2.5}$, and H_2SO_4 will be minimized through use of natural gas as the primary fuel; limited firing of ULSD with a maximum sulfur content of 15 parts per million by weight (ppmw) will also minimize emissions of these pollutants.

2.3.2.1 Selective Catalytic Reduction

SCR, a post-combustion chemical process, will treat exhaust gases downstream of the CTG. The SCR process will use 19% aqueous NH_3 as a reagent. Aqueous NH_3 will be injected into the flue gas stream upstream of the SCR catalyst, where it will mix with NO_x. The catalyst bed will be located in an integral separate housing along with the oxidation catalyst. The temperature of the SCR will be maintained within its designed operating zone by the introduction of ambient air into the exhaust gas from the CTG to cool the exhaust gas. The temperature-controlled exhaust gases with the injected NH_3 will pass over the catalyst and the NO_x will be reduced to nitrogen gas (N_2) and H_2O. The SCR system will reduce NO_x concentrations to 2.5 parts per million by volume dry basis corrected to 15 percent O_2 (ppmvdc) during natural gas firing and 5.0 ppmvdc during ULSD firing, across all steady-state operating loads and ambient temperatures.

A small amount of NH_3 will remain unreacted through the catalyst, which is called “ammonia slip.” The ammonia slip will initially be limited to 5.0 ppmvdc at all load conditions and ambient temperatures for both fuels, with an optimization goal of 2.0 ppmvdc. For ULSD firing, the proposed BACT limit is 5.0 ppmvdc.

2.3.2.2 Oxidation Catalyst

An oxidation catalyst system will be located within the same housing as the SCR to control emissions of CO and VOC. Exhaust gases from the CTG will flow through the catalyst bed where the CO and VOC will oxidize to form carbon dioxide (CO_2) and H_2O. The oxidation catalyst system will reduce CO concentrations to ***3.5*** ppmvdc in the exhaust gas during natural gas firing and 5.0 ppmvdc during ULSD firing, across all steady-state operating loads and ambient temperatures. VOC will be limited to 2.0 ppmvdc for both fuels.

2.4 ANCILLARY SOURCES

2.4.1 Emergency Diesel Generator

The purpose of the emergency diesel generator is to provide power to critical equipment in the event of a power failure, including the distributed control system, combustion turbine turning gear, combustion turbine lube oil pumps, as well as lighting and communication systems. ***The emergency diesel generator will not provide black-start capability for the new CTG unit.*** The emergency diesel generator will be rated at approximately 500 kWe (581 kW mechanical) and will be fired with ULSD. The engine will be a Tier 4 engine that will satisfy the emissions requirements of 40 CFR 1039.104(g), Table 1 and 40 CFR 60 Subpart IIII. Tier 4 refers to the fourth Tier in a sequence of USEPA emission standards for non-road diesel engines. Some of the Tier 1-4 designations are also used for certain requirements for stationary engines. The Tier 4 limit under 40 CFR 1039.104(g) is an alternate limit which applies a percentage of a manufacturer's engine family that does not require SCR for compliance. The emergency diesel generator will be a package unit that will contain a ULSD tank. Operation of the emergency generator engine will be limited to no greater than 300 hours per year.

2.4.2 Emergency Diesel Fire Pump

Two fire pumps will be provided to ensure 100% backup of the fire protection system water supply. One fire pump will be driven by an electric motor and the other will be driven by a diesel engine. Each pump will be capable of delivering total system requirements at design pressure and flow rate with any one pump out of service. The diesel-engine-driven fire pump will be rated at 135 bhp and will be fired with ULSD. The engine will be a Tier 3 engine that will satisfy the emissions requirements of 40 CFR 60 Subpart IIII. Fuel supply for the fire pump will be located in a tank adjacent to the pump. Operation of the emergency fire pump engine will be limited to no greater than 300 hours per year.

2.5 EMISSIONS SUMMARY

2.5.1 Combustion Turbine

Table 2-1 presents a summary of the proposed limits for pollutants emitted from the CTG at steady-state full-load operation. Startup/shutdown (SUSD) emissions are presented in Table 2-2. The limits incorporate the LAER and BACT requirements as discussed in Sections 4 and 5. Calculations for emission rates for all steady-state operating conditions and ambient temperatures are provided in Appendix B.

Project SUSD scenarios are presented in Table 2-2. Emissions during startup may, for some pollutants, result in an increase in short-term (pounds per hour [lb/hr]) emission rates. Potential annual emissions estimates for the proposed Project, as provided in Section 2.5, include emissions from SUSD.

Table 2-1: Summary of Proposed Emission Limits for the CTG (Steady-State Operation)[a]

Pollutant	Natural Gas Firing			ULSD Firing			Basis
	lb/MMBtu[b]	ppmvdc	lb/hr[c]	lb/MMBtu[b]	ppmvdc	lb/hr[c]	
NO_x	0.0092	2.5	31.5	0.0194	5.0	67.3	BACT/LAER
VOC	0.0026	2.0	8.9	0.0027	2.0	9.4	BACT
CO	***0.0079***	***3.5***	***25.9***	0.0118	5.0	41.0	BACT
PM/PM_{10}/$PM_{2.5}$ ***>= 75% load***	***0.0073***	n/a	18.1	***0.026***	n/a	***65.8***	BACT
PM/PM_{10}/$PM_{2.5}$ >= MECL[d] but < 75% load	***0.012***	***n/a***	***18.1***	***0.046***	***n/a***	***65.8***	***BACT***

SO_2	0.0015	n/a	5.14	0.0015	n/a	5.21	BACT
H_2SO_4	0.0016	n/a	5.48	0.0018	n/a	6.25	BACT
NH_3	0.0068 (initial) 0.0027 (goal)	5.0 (initial) 2.0 (goal)	23.3(initial) 9.3 (goal)	0.0072	5.0	25.0	BACT
GHG as CO_2e	1,178 lb/MW-hr (gross)[e]	n/a	407,575	1,673 lb/MW-hr (gross)[e]	n/a	565,252	BACT

[a] Project may exceed these limits during defined periods of startup, shutdown and malfunction.
[b] lb/MMBtu = pounds per million British thermal units. Emission rates are based on HHV of fuel.
[c] Maximum mass emission rate across all steady-state loads and ambient temperatures
[d] ***Minimum Emissions Compliance Load (MECL), ranges from 30 -40% load based on fuel and ambient temperature.***
[e] BACT for GHGs is expressed as an efficiency based limit at International Organization for Standardization (ISO) conditions (base load, 59°F, 1 atmosphere pressure, and 60% relative humidity, gross output basis.

Table 2-2: Proposed Provisional Startup and Shutdown Emission Limits for the Combustion Turbine

Pollutant	Fuel	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	$PM/PM_{10}/PM_{2.5}$ (lb/event)
Startup	Natural Gas	151	130	9	9.1
	ULSD	219	163	12	48.2
Shutdown	Natural Gas	7	133	25	4.2
	ULSD	8	25	3	12.8

The SUSD limits provided in Table 2-2 are proposed as provisional limits since actual experience in the first year of operation may indicated a change in these limits is necessary. Short-term SUSD emission limits will be evaluated after a year of actual operation and revised values may be proposed if needed. If revised short-term SUSD emission limits are proposed, it will be done in accordance with the requirements of 310 CMR 7.02 and with the requirements of 310 CMR 7.00, Appendix C, as applicable.

2.5.2 Ancillary Sources

Table 2-3 provides emissions from the Project's ancillary equipment (emergency diesel generator and emergency diesel fire pump). Emissions of air contaminants from this equipment have been estimated based upon vendor emission guarantees, USEPA emission factors, mass balance calculations, and engineering estimates.

Table 2-3: Emissions from Ancillary Equipment

Pollutant	Emergency Generator (lb/hr)	Emergency Fire Pump (lb/hr)
PM_{10}	0.17	0.074
$PM_{2.5}$	0.17	0.074
SO_2	0.0075	0.0018
H_2SO_4	5.78×10^{-4}	1.38×10^{-4}
NO_x	4.48	0.89
CO	4.48	1.113
VOC	0.24	0.29

Pb	$1.60x10^{-5}$	$3.76x10^{-6}$
CO_{2e}*	819	195

*carbon dioxide equivalent

2.6 PROJECT POTENTIAL ANNUAL EMISSIONS

Potential annual emissions from the proposed Project were estimated using the following worst-case assumptions for any rolling 12 months of operation. However, as discussed in Section 3.1.4.4, under applicable NSPS Subpart TTTT requirements, operation over three years (based on three-year rolling average) will not exceed a 40% capacity factor (CF). ***Compliance with this three-year rolling average 40% capacity factor is determined in accordance with Subpart TTTT, based on net electric output (actual net-electric sales divided by potential net-electric generation if the unit had operated for 8,760 hours in each year).***

The operation of the new CTG will be limited as follows on a rolling 12-month (R12M) basis

- ***O***peration of the CTG ***(all fuels) limited to*** 4,380 hours (50% CF) per ***R12M.***
- ULSD firing limited to 720 hours per ***R12M***;
- ***Total quantity of natural gas fired limited to 14,554,740 MMBtu (50º F full-load firing rate times 4,380 hours);***
- ***Total quantity of ULSD fired limited to 2,499,120 MMBtu (0º F full-load firing rate times 720 hours)***
- ***Incorporation*** of SUSD events, based on a conservative scenario (180 SUSD cycles on natural gas and 80 SUSD cycles on ULSD). ***The actual number of SUSD events is not specifically limited, but SUSD emissions will be tracked and included in total emissions to ensure the R12M emission limits are not exceeded.***

Potential annual emissions for the proposed Project are summarized in Table 2-4.

Table 2-4: Summary of Potential Annual Emissions (tons per year)

Pollutant	CTG	Emergency Generator Engine	Emergency Fire Pump Engine	Project Totals
PM	***60.4***	0.03	0.01	***60.5***
PM_{10}	***60.4***	0.03	0.01	***60.5***
$PM_{2.5}$	***60.4***	0.03	0.01	***60.5***
SO_2	11.1	$1.1x10^{-3}$	$2.7x10^{-4}$	11.1
NO_x	103.5	0.67	0.13	104.3
CO	***94.0***	0.67	0.17	***94.8***
VOC	23.3	0.04	0.04	***24.4***[b]
H_2SO_4	12.0	$8.7x10^{-5}$	$2.1x10^{-5}$	12.0
NH_3	50.3	---	---	50.3
Pb	0.004	$2.4x10^{-6}$	$5.6x10^{-7}$	0.004
CO_{2e}[a]	932,325	123	29	***934,041***[c]
Formaldehyde (max HAP)	1.6	$6.0x10^{-5}$	$2.1x10^{-4}$	1.6
Total HAPs	3.9	$1.3x10^{-3}$	$7.2x10^{-4}$	3.9

a. GHGs expressed as carbon dioxide equivalents, based on global warming potential of each individual GHG.

b. Includes 1.0 tpy VOC emissions from ULSD working and breathing losses.

c. Includes allowance for 1,561 tpy CO_2e from methane leaks and 3 tpy CO_2e from potential SF_6 leaks.

3.0 REGULATORY APPLICABILITY EVALUATION

The USEPA and MassDEP have promulgated regulations that establish ambient air quality standards and emission limits for sources of air pollution. Pursuant to 310 CMR 7.02 and Appendix A, MCPA/NNSR applications must demonstrate compliance with applicable regulations. Accordingly, this section identifies the federal and Massachusetts regulations that may apply to the proposed Project and discusses how the Project will comply with all applicable requirements.

The federal regulations reviewed here include: New Source Review (NSR), NAAQS, NSPS, NESHAPs; the Acid Rain Program; the Title V Operating Permit Program; and NO_x Budget Program requirements. These federal regulations are discussed since the MassDEP is obligated by the Clean Air Act to address these requirements as part of the state preconstruction permitting process. Applicable Massachusetts regulations for the MCPA/NNSR process are also discussed.

3.1 FEDERAL REGULATIONS

3.1.1 New Source Review

NSR applies to proposed new major sources of air pollutants. The NSR program for major sources includes two distinct permitting programs, PSD permitting for projects located in areas designated as unclassified or attainment with the NAAQS, and NNSR permitting for projects located in areas designated as nonattainment with the NAAQS. As an area may be in attainment with one or more NAAQS, but in nonattainment with one or more other NAAQS at same time, an individual project may be subject to both PSD and NNSR permitting depending upon its potential emissions. The federal PSD program under 40 CFR 52.21 applies to subject sources in Massachusetts and the program is administered by the MassDEP. PSD review applicability for the Project is discussed in the PSD Permit Application, which is provided under separate cover.

3.1.2 Non-Attainment New Source Review

All of Massachusetts was recently designated as in attainment with the 2008 8-hour O_3 standard, with the exception of Dukes County. However, as discussed in Section 3.2, all of Massachusetts is within the Northeast Ozone Transport Region (OTR) as designated by the Clean Air Act. New major sources or major source modifications in the OTR are subject to the provisions of NNSR that apply to moderate O_3 nonattainment areas. Also, 40 CFR 81 still retains a moderate nonattainment designation for all of Massachusetts for the 1997 8-hour O_3 standard. Appendix A contains permitting requirements for new sources and modifications of existing major sources that correspond to the provisions of NNSR for serious O_3 nonattainment areas. Accordingly, Appendix A governs the NNSR permitting requirements for the Project.

Under Appendix A, a project located in an area designated as nonattainment for O_3 must satisfy NNSR requirements for NO_x and/or VOC emissions (as precursors of O_3) if emissions of NO_x and or VOC exceed the NNSR thresholds. The Station is an existing NNSR major source for both NO_x and VOC emissions. Accordingly, as a modification of the Station, if the Project results in a net increase in NO_x and/or VOC emissions above the applicable NNSR Review Threshold, NNSR will be required. Pursuant to Appendix A, the NNSR review threshold is 25 tons per year (tpy), for both NO_x and VOC emissions. ***The evaluation of applicability of NNSR for NO_x and VOC must also include any contemporaneous increase or decrease in NO_x and/or VOC emissions that have occurred at Canal Station in the past five years. Contemporaneous increases can result from new equipment or permit modifications, and contemporaneous decreases can typically result from new voluntary permit restrictions or equipment shutdowns.***

Table 3-1 presents a comparison of the Project's potential emissions of NO_x and VOC with the applicable NNSR permitting requirements. ***Canal Station has not had any contemporaneous increases or decreases in NO_x or VOC emissions in the last five years.***

Table 3-1: Summary of Project Emissions and Applicable NNSR Thresholds

Pollutant	Project PTE (tpy)	NNSR Review Threshold (tpy)	NNSR Applies (Yes/No)
NO_x	104.3	***25***	Yes
VOC	***24.4***	***25***	No

As shown in Table 3-1, the Project will be a major modification under NNSR for NO_x but not for VOC. Consequently, the Project is subject to Appendix A/NNSR requirements with respect to NO_x only. Under the NNSR regulations, subject sources must satisfy the following requirements:

- application of LAER controls;
- procurement of emissions offsets;
- analysis of alternatives; and,
- certification of compliance.

3.1.2.1 Lowest Achievable Emission Rate

LAER is defined under Appendix A, as the most stringent emission limitation achieved in practice, or which can reasonably be expected to occur in practice, for a category of emission sources taking into consideration each air contaminant that must be controlled. The application of LAER must meet or exceed all applicable emission standards established under 310 CMR 7.00 or 40 CFR 60 or 63. The application of LAER is based entirely upon technical feasibility without consideration of other factors. The Project will achieve LAER for the CTG by using DLN combustion for natural gas firing, water injection for ULSD firing, and SCR for both fuels. Section 4 describes in detail the applicable LAER limits for NO_x for each emission source and how the proposed controls will meet these limits.

3.1.2.2 Emissions Offsets

A project subject to Appendix A/NNSR permitting must obtain emissions offsets for each subject pollutant as a condition of approval. The emissions offsets must satisfy two criteria: (1) offset the emissions increase from the proposed Project; and (2) provide a net air quality benefit. Offsets for NO_x are required at a minimum ratio of 1.2:1 in all areas of Massachusetts as specified in 310 CMR 7.00, Appendix A. The MassDEP requires an additional 5% of offsets, bringing the effective minimum ratio to 1.26:1. Therefore, 131.4 tpy of NO_x offsets will be required for the Project. Offsets can be obtained from existing sources that have achieved emission reductions greater than that required by regulation, or have permanently curtailed or ceased operations. The resulting emission reductions from such actions must be certified by a state agency where the source is (or was) located as having met the requirements for being approved as certified emissions offsets. The Project will obtain offsets as required prior to issuance of the Final Air Plan Approval by MassDEP. NRG has control of 4,209.2 tons per year of NO_x offsets that have been certified by the New York State Department of Environmental Conservation in 2012. These NO_x offsets were created by the permanent shutdown of Lovett Generating Station ***in Rockland County***, which was located in the Hudson River Valley in Tomkins Cove, NY. NRG has requested that MassDEP pursue obtaining a Memorandum of Understanding with New York State Department of Environmental Conservation to allow these ERCs to be used for the Project.

As specified in 310 CMR 7.00 Appendix A, NO_x emission offsets must be obtained from a source within the same Ozone Transport Region. Since the Lovett Station emission reductions have occurred, NYSDEC has certified the ERCs, and Lovett Station is located in the Ozone Transport Region that includes both Massachusetts and New York, as defined in the Clean Air Act, therefore the ERCs meet these requirements. Additionally, 310 CMR 7.00 Appendix A specifies that emission offsets must occur and be obtained from a source in the same nonattainment area, unless:

- ***The emission reductions are obtained from another area that has an equal or higher nonattainment classification than the nonattainment area in which the new source is proposed; and***

- ***When the new source or modified source is proposed in a nonattainment area, emissions from the other area contribute to a violation of a National Ambient Air Quality Standard (NAAQS) in the nonattainment area in which the new or modified source would be constructed (i.e., from an upwind nonattainment area).***

Barnstable County, Massachusetts currently has a "Moderate" nonattainment designation for the 1997 8-hour O_3 standard and is classified as "Unclassifiable/Attainment" for the 2008 8-hour O_3 standard. Rockland County, New York also has a "Moderate" nonattainment designation for the 1997 8-hour O_3 standard and is classified as "Marginal" nonattainment for the 2008 8-hour O_3 standard. Therefore, Rockland County, New York has an equal or higher nonattainment classification, as compared to Barnstable County, Massachusetts. This satisfies the first requirement noted above. Additionally, New York State is considered "upwind" of Massachusetts for weather conditions associated with elevated ground-level O_3 concentrations. Precursor pollutants from New York State contribute to elevated ground-level concentrations of O_3 in Massachusetts. Therefore, ERCs from the Lovett Station satisfy the second requirement.

3.1.2.3 Alternatives Analysis

In accordance with Appendix A, the MCPA application must include an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed Project. The applicant must demonstrate to the satisfaction of the MassDEP that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of the facility location and construction. This demonstration is comprised of analyses NRG has made and presented in several places in this application and in other permitting documents submitted to Massachusetts agencies. Specifically, the detailed control technology analyses presented in Sections 4 and 5 of this application provide this justification for emissions control techniques. Sections 3 and 4 of the Project's Energy Facility Siting Board (EFSB) Petition (December 2015) provide analyses and justifications relative to alternative sites and project mitigation measures. The EFSB Petition also provides an analysis and justification of the Project with respect to site alternatives.

The detailed alternatives analysis provided by these supporting documents is provided in Appendix C.

3.1.2.4 Compliance Certification

All major stationary sources in Massachusetts owned or operated by the applicant subject to federally enforceable emission limits must be in compliance all provisions of 310 CMR 7.00, et seq or on a compliance schedule to meet such requirements. NRG (a separately affiliated party to Canal 3) owns and operates the existing Station, as well as two facilities on Martha's Vineyard, which are in compliance with all currently applicable requirements.

3.1.3 Ambient Air Quality Standards

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2, PM, nitrogen dioxide (NO_2), CO, O_3, and lead (Pb). PM is characterized according to size; PM having an effective aerodynamic diameter of 10 microns or less is referred to as PM_{10}, or "respirable particulate." PM having an effective aerodynamic diameter of 2.5 microns or less is referred to as $PM_{2.5}$, or "fine particulate"; $PM_{2.5}$ is a subset of PM_{10}. MassDEP has generally adopted the NAAQS as Massachusetts Ambient Air Quality Standards (MAAQS).

The NAAQS have been developed for various durations of exposure. The NAAQS for short-term periods (24 hours or less) typically refer to pollutant levels that cannot be exceeded except for a limited number of cases per year. The NAAQS for long-term periods refer to pollutant levels that cannot be exceeded for exposures averaged typically over one year. The NAAQS include both "primary" and "secondary" standards. The primary standards are intended to protect human health and the secondary standards are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of air pollutants.

One of the basic goals of federal and state air pollution regulations is to ensure that ambient air quality, including consideration of background levels and contributions from existing and new sources, is in compliance with the NAAQS. Toward this end, for each criteria pollutant, every area of the United States has been designated as one of the following categories: attainment; unclassifiable; or nonattainment. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of, such air quality. In areas designated as unclassifiable, there are limited air quality data, and those areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment, the air quality with respect to the pollutant is worse than the NAAQS. These areas must take actions to improve air quality and achieve attainment with the NAAQS within a certain period of time.

If a new major source or a major modification of an existing major source of air pollution is proposed, it must undergo NSR. There are two NSR programs, one for sources being built in attainment/unclassifiable areas, and one for sources in nonattainment areas. The NSR program for sources in attainment/unclassifiable areas is known as the PSD Program. The NSR program for sources being built in nonattainment areas is known as the NNSR Program.

The Project location is presently classified as "attainment" for SO_2 and NO_2, and "attainment/unclassifiable" (combined definition) for CO, Pb, and all particulates. Thus, emissions of these pollutants are evaluated under the PSD program. Except for Dukes County, all of Massachusetts was reclassified as attainment with respect to the 2008 8-hour O_3 standard on May 21, 2012. However, 40 CFR 81 still retains a moderate nonattainment designation for the 1997 8-hour O_3 standard. Also, due to the federal Clean Air Act requirements for the Northeast OTR, which includes all of Massachusetts, as well as the MassDEP NNSR provisions of 310 CMR 7.00, Appendix A, all of Massachusetts is still treated as an O_3 nonattainment area for NSR purposes.

To identify new emission sources with the potential to have a significant impact on ambient air quality, the USEPA and MassDEP have adopted significant impact levels (SILs) for the criteria pollutants. Applicants for new major sources or major modifications of existing major sources are required to perform dispersion modeling analyses to predict air quality impacts of the new or modified sources in comparison to the SILs. If the predicted impacts of the new or modified sources are less than the SIL for a particular pollutant and averaging period, then the impacts are considered "insignificant" for that pollutant and averaging period. However, if the predicted impacts of the new or modified sources are greater than the SIL for a particular pollutant and averaging period, then further impact evaluation is required. This additional evaluation must consider measured background levels of pollutants and emissions from both the proposed new sources and existing interactive sources. Further, in areas attaining the NAAQS, air quality is not permitted to degrade beyond specified levels, called PSD increments, as a result of the cumulative impacts of "PSD increment consuming" sources. In general, sources constructed or modified after pollutant and area-specific "baseline dates" consume PSD increment.

Table 3-2 presents the NAAQS and MAAQS as well as the corresponding SIL and PSD increment values for the various criteria pollutants and averaging periods.

Section 6.0 presents a detailed evaluation of the Project's compliance with the applicable ambient air quality standards.

3.1.4 New Source Performance Standards

NSPS are technology-based standards applicable to new and modified stationary sources. NSPS have been established for approximately 70 source categories. Based upon a review of these standards, several subparts are applicable to the proposed Project. The Project's compliance with each of these standards is presented in the following sections.

3.1.4.1 40 CFR 60 – Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A, as identified in the applicable Subpart. Because the Project is subject to other Subparts of the regulation, the requirements of Subpart A will also apply. The Project will comply with the applicable notifications, performance testing, recordkeeping and reporting outlined in Subpart A and the applicable Subparts.

3.1.4.2 40 CFR 60 – Subpart KKKK – Stationary Combustion Turbines

Subpart KKKK places emission limits on NO_x and SO_2 from new combustion turbines. The proposed CTG will be subject to this standard. For new CTGs with a rated heat input greater than 850 MMBtu/hr, NO_x emissions are limited to the following:

- 15 ppmvdc for natural gas and 42 ppmvdc for oil; or,
- 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour [lb/MW-hr]) for natural gas and 160 ng/J or useful energy output (1.3 lb/MW-hr) for oil.

Additionally, SO_2 emissions must meet one of the following:

- emissions limited to 110 ng/J (0.90 lb/MW-hr) gross output; or,
- emissions limited to 26 ng/J (0.060 lb/MMBtu).

As described in Section 2.0, the proposed Project will use DLN combustors and an SCR system to control NO_x emissions to 2.5 ppmvdc during natural gas firing. H_2O injection and SCR will be used to control NO_x emissions to 5.0 ppmvdc during ULSD firing. SO_2 emissions will be limited to 0.0015 lb/MMBtu when firing both pipeline-quality natural gas and ULSD. As such, the Project will meet the emission limits under Subpart KKKK.

Table 3-2: National and Massachusetts Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS/MAAQS[a] (µg/m³)[b]		Significant Impact Level (µg/m³)	PSD Increment (µg/m³)
		Primary	Secondary		
NO_2	Annual[c]	100	Same	1	25
	1-hour[d]	188	None	7.5	Not yet proposed
SO_2	Annual[c,e]	80	None	1	20
	24-hour[e,f]	365	None	5	91
	3-hour[f]	None	1,300	25	512
	1-hour[g]	196	None	7.8	None
$PM_{2.5}$	Annual[h]	12	Same	0.3	4
	24-hour[i]	35	Same	1.2	9
PM_{10}	Annual[j]	50	Same	1	17
	24-hour[k]	150	Same	5	30
CO	8-hour[f]	10,000	None	500	None
	1-hour[f]	40,000	None	2,000	None
O_3	8-hour[k]	137	Same	None	None
	1-hour[l]	235	Same	None	None
Pb	***Rolling*** 3-month[c]	0.15	Same	None	None

[a] The MAAQS were last amended in April 1994, prior to promulgation of the NAAQS for 1-hr NO_2, 1-hr SO_2, $PM_{2.5}$, and 8-hr O_3. Therefore, these standards are only NAAQS.

[b] µg/m³ = micrograms per cubic meter

[c] Not to be exceeded.

[d] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 100 parts per billion (ppb) (188 µg/m³).

[e] The 24-hour and annual average primary NAAQS for SO_2 have been revoked. However, these standards remain in effect until one year after an area is designated for the new 1-hour standard, and they also remain in effect as MAAQS.

[f] Not to be exceeded more than once per year.

[g] To attain this standard, the 3-year average of 99th percentile of the daily maximum 1-hour average at each monitor within an area must not exceed 75 ppb (196 µg/m³).

[h] To attain this standard, the 3-year average of weighted annual mean $PM_{2.5}$ concentrations at community-oriented monitors must not exceed 12 µg/m³.

[i] To attain this standard, the 3-year average of 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 µg/m³.

[j] MAAQS only. NAAQS for annual PM_{10} and 1-hr O_3 no longer exist. Annual PM_{10} is not to be exceeded based on 3 year average. 1 hour O_3 is based on expected number of days in exceedance < one per year.

[k] ***To attain this standard, the 3-year average of the fourth highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.070 ppm.***

[l] To attain this standard, ***the number of days per calendar year, with maximum hourly average concentration greater than 0.12 ppm, must not exceed 1***.

3.1.4.3 40 CFR 60 – Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines that commence operation after July 11, 2005. Relevant to the proposed Project, this rule applies to the emergency generator engine and emergency fire pump engine.

For model year 2010 and later, fire pump engines with a displacement less than 30 liters per cylinder and an energy rating between 100 and 175 horsepower (hp), Table 4 of Subpart IIII provides the following emission limits:

- 4.0 grams per kilowatt-hour (g/kW-hr) (3.0 grams per horsepower-hour [g/hp-hr]) of NO_x + non-methane hydrocarbons (NMHC)
- 5.0 g/kW-hr (3.7 g/hp-hr) of CO
- 0.30 g/kW-hr (0.22 g/hp-hr) of PM

The Project will install a fire pump engine meeting these emission standards.

To comply with Subpart IIII, new emergency stationary CI engines with a displacement less than 30 liters per cylinder must meet the emission standards per 40 CFR 60.4205(b). To meet these limits and satisfy BACT requirements, the proposed 581-kW (mechanical) new emergency stationary CI engine will meet USEPA's Tier 4 limits under 40 CFR 1039.101, Table 1 and 40 CFR 1039.104(g), Table 1, as follows:

- 3.5 g/kW-hr (2.6 g/hp-hr) of NO_x
- 0.19 g/kW-hr (0.14 g/hp-hr) of VOC
- 3.5 g/kW-hr (2.6 g/hp-hr) of CO
- 0.1 g/kW-hr (0.07 g/hp-hr) of PM (filterable)

The Project will install an emergency generator engine meeting these emission standards.

3.1.4.4 40 CFR 60 – Subpart TTTT – Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units

Subpart TTTT for GHG emissions from electric generating units (including combustion turbines) was promulgated by USEPA on August 4, 2015. A natural gas-fired combustion turbine with an annual capacity factor (on a three-year rolling basis) that exceeds the combustion turbines "design efficiency," expressed as a percent, as defined in the rule, is considered a "baseload" unit. The applicable standard for a baseload combustion turbine is 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MW-hr) gross energy output or 1,030 lb CO_2/MW-hr net energy output. The "design efficiency" is the rated efficiency of the turbine at ISO conditions, net basis.

The "design efficiency" value for the proposed H-class combustion turbine in a simple-cycle configuration is nominally 40%. Accordingly, if the Project were to operate, on a rolling 3-year average, in excess of a capacity factor of 40%, the Project would need to meet the 1,000 lb CO_2/MW-hr gross – 1,030 lb CO_2/MW-hr net energy output standards. However, as long as the Project operates as a non-base-load facility (i.e., its annual capacity factor is equal to or less than the 40% design efficiency) then the Project is subject to different a requirement, as described below.

Under Subpart TTTT, non-baseload, multi-fuel combustion turbines must comply with a mass-based standard, which is expressed in the units of lbs of CO_2 per MMBtu heat input. For multi-fuel units like the proposed Project, compliance must be demonstrated with a sliding scale standard in the range of 120-160 lbs CO_2/MMBtu, where the specific limit is calculated based on the percent of the rolling 12-month heat input that is natural gas and ULSD, respectively. Compliance with this limit can be demonstrated using the respective carbon contents of natural gas and ULSD. As a multi-fuel non-baseload unit, the Project can be operated up to 4,380 full load hours (50% CF) in any specific 12-month period with up to 720 full-load hours in this 12-month period on ULSD, and maintain compliance with the sliding scale multi-fuel lbs CO_2/MMBtu requirement, based on the carbon contents of natural gas and ULSD.

The Project will comply with a maximum three-year rolling average capacity factor of no more than 40% so as to qualify as a non-baseload unit under Subpart TTTT. In any single 12-month period, the operation of the Project may be as much as 4,380 hours (50% CF) to accommodate projected worst-case operating scenarios. However, for any 12-month period that the Project operates at a 50% CF, the Project will be required to operate at an average capacity factor of 35% in the following 2 years, in order to comply with the 3-year rolling average 40% CF limit.

3.1.5 National Emission Standards for Hazardous Air Pollutants (40 CFR 61 and 63)

There are no 40 CFR 61 standards applicable to the proposed Project. Current USEPA Compilation of Air Pollutant Emission Factors (AP-42), other applicable emission factors, and vendor information were reviewed in determining if the proposed Project will be subject to a standard under 40 CFR 63. The existing Facility is a major source of HAP emissions and, therefore, the Project is considered a major source under 40 CFR 63.

3.1.5.1 40 CFR 63 – Subpart YYYY – Stationary Combustion Turbines

The Station is an existing major source of HAP emissions; therefore, the Project has been evaluated with respect to Subpart YYYY for Stationary Combustion Turbines, which was promulgated on March 5, 2004. In April 2004, USEPA proposed to "delist" natural gas-fired combustion turbines from the NESHAPs program. In August 2004, USEPA stayed (indefinitely) the combustion turbine NESHAPs for natural gas-fired turbines (including any unit which fires oil less than 1,000 hours per calendar year) pending a final decision on delisting; no final delisting decision has been made. Since the Project is proposing to fire no more than 720 hours of oil in any calendar year, ***the operating, monitoring and reporting requirements of Subpart*** YYYY do not apply ***as long as the stay is in effect. The initial notification requirements of Subpart YYYY under 40 CFR 63.6145 still do apply. It is also noted that*** the Project will be equipped with lean pre-mix combustor for natural gas firing that effectively limit products of incomplete combustion such as formaldehyde. In addition, the oxidation catalyst system will be effective at limiting formaldehyde emissions on both natural gas and ULSD.

3.1.5.2 40 CFR 63 – Subpart ZZZZ – Reciprocating Internal Combustion Engines

The emergency generator diesel engine and emergency diesel fire pump engine are subject to the NESHAPs under 40 CFR 60 Subpart ZZZZ. These NESHAPs generally apply, with the same requirements for new emergency generators, regardless of major or minor HAP source status. For new emergency units, the NESHAPs requirements are satisfied if the units comply with the NSPS under 40 CFR 60, Subpart IIII. As stated in Section 3.1.4.3, the Project will purchase emergency generator and fire pump engines that comply with NSPS Subpart IIII.

3.1.6 Acid Rain Program

Title IV of the Clean Air Act Amendments of 1990 required USEPA to establish a program to reduce emissions of acid-rain-forming pollutants, called the Acid Rain Program. The overall goal of this program is to achieve significant environmental benefits through reduction in SO_2 and NO_x emissions. To achieve this goal, the program employs a market-based approach for controlling air pollution. Under the market-based aspect of the program, affected units are allocated SO_2 allowances by the USEPA, which may be used to offset emissions, or traded under the market allowance program. In addition, in order to ensure that facilities do not exceed their allowances, affected units are required to monitor and report their emissions using a Continuous Emissions Monitoring System (CEMS), as approved under 40 CFR Part 75.

The Project is subject to the Acid Rain Program based on the provisions of 40 CFR 72.6(a)(3) because the CTG is considered a "utility unit" under the program definition and does not meet the exemptions listed under paragraph (b) of this Section. The Project will be required to submit an Acid Rain Permit application at least 24 months prior to the date on which the affected units commence operation. The Project will submit an Acid Rain Permit application in compliance with these requirements prior to this deadline.

3.1.7 NO_x and SO_2 Budget Programs

On March 10, 2005, USEPA issued the Clean Air Interstate Rule (CAIR), which required reductions in emissions of NO_x and SO_2 from large fossil fuel-fired electric generating units on a state-specific basis using a cap-and-trade system. The rule provided both an annual emissions budget and/or an ozone season emission budget for certain affected states. Massachusetts was subject to ozone-season NO_x requirements under CAIR, but was not subject to any annual NO_x or SO_2 requirements under CAIR.

On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit (the Court) issued an opinion vacating and remanding CAIR. However, on December 23, 2008, the Court granted rehearing only to the extent that it remanded the rules to USEPA without vacating them. The December 23, 2008 ruling left CAIR in place until the USEPA issued a new rule to replace CAIR, in accordance with the July 11, 2008 provisions.

On July 6, 2011, the USEPA issued the Cross-State Air Pollution Rule (CSAPR), which replaced CAIR. However, Massachusetts was not subject to any requirements under CSAPR. After legal delays, CSAPR officially replaced CAIR, effective January 1, 2015.

While Massachusetts is not subject to CSAPR, and CAIR is no longer in effect, Massachusetts is prevented from "backsliding" under the Clean Air Act. As a result, the MassDEP has indicated that it will implement regulations to maintain the historical CAIR restrictions on ozone-season NO_x emissions. At this time, replacement regulations for CAIR have not been promulgated.

The Project will comply with the rules in effect when the Project becomes operational.

3.1.8 Accidental Release Program

Section 112r of the Clean Air Act governs the storage and handling of certain chemicals. Aqueous NH_3 will be used as the reagent for the SCR systems for controlling NO_x emissions. Aqueous NH_3 at a concentration of 19% by weight will be supplied from the two existing 60,000-gallon storage tanks. Facilities that store aqueous NH_3 solutions containing less than 20% ammonia by weight are not subject to the accidental release requirements under Section 112r. However, Section 112r includes a general-duty clause covering the storage of all chemicals of all quantities. To comply with the general-duty clause, an analysis of potential impacts from a hypothetical worst-case ammonia spill is provided in Section 6.

3.1.9 Title V Operating Permit Program

USEPA has delegated MassDEP authority to administer the Title V Operating Permit Program (40 CFR 70), under its regulations at 310 CMR 7.00: Appendix A. The Station is an existing major source and is operating under Title V Operating Permit Application No. 4V95058 and SE-13-022. In accordance with 310 CMR 7.00, Appendix A, an application for a significant modification of the Title V Operating Permit must be submitted to the MassDEP no later than nine months prior to the planned modification. NRG will submit an application for a significant modification of the Title V Operating Permit within the required timeframe.

3.2 COMMONWEALTH OF MASSACHUSETTS REGULATIONS

Following is a summary of the applicable MassDEP requirements for the MCPA/NNSR permit process.

3.2.1 General Regulations to Prevent Air Pollution

Regulations at 310 CMR 7.01 establish general requirements for preventing air pollution, and prohibits the willful or negligent creation of a condition of air pollution. 310 CMR 7.01 also prohibits the making of false, inaccurate, incomplete or misleading statements in required recordkeeping or information submitted to MassDEP, and requires persons submitting information to certify they have examine the information and believe it to be true, accurate, and complete. The Project will comply with all requirements of 310 CMR 7.01.

3.2.2 Comprehensive Plan Approval

Regulations at 310 CMR 7.02 establish the requirement for a plan approval to be issued prior to the construction, reconstruction, alteration, or operation of a facility that may emit contaminants to the ambient air. The proposed Project exceeds several of the thresholds requiring submittal of a Comprehensive Plan Approval (CPA) application, set forth at 310 CMR 7.02(5)(a). Among these thresholds, the proposed Project will increase potential emissions of an air contaminant by 10 tpy or more, will include a fuel combustion unit rated at 40 MMBtu/hr or greater, and will be subject to Emissions Offsets and Nonattainment Review under 310 CMR 7.00: Appendix A.

This document and its attached appendices contain the information and materials required for a CPA application under 310 CMR 7.02(5)(c), including:

- completed MassDEP CPA application forms with required Professional Engineer's stamp;
- a description of the proposed Project, including site plans, drawings, and detailed emission calculations (operating and maintenance procedures will be provided after final equipment vendors have been selected);
- a demonstration of compliance, as required under 310 CMR 7.02(8)(a), with the most stringent applicable emission limits of LAER, BACT, NSPS, NESHAP, and MACT; and,
- air dispersion modeling demonstrating compliance with NAAQS and MAAQS.

The designation *Major* Comprehensive Plan Approval (MCPA; MassDEP Category BWP-AQ-03) is based on the MassDEP Timely Action Schedule and Fee Provisions (310 CMR 4.00), where a *Major* Comprehensive Plan Approval includes any CPA that is subject to NNSR (among other MCPA triggers).

3.2.3 Sulfur in Fuel Standard

Regulations at 310 CMR 7.05 establish fuel sulfur content and ash content limits for fossil fuel combustion facilities located in Massachusetts. These regulations generally apply to liquid fossil fuels. 310 CMR 7.05(1)(a), which was amended on July 20, 2012, establishes several stepped limits for sulfur content in distillate oil, which is limited to 0.05% by weight through June 30, 2018 and to 0.0015% by weight on and after July 1, 2018. Natural gas has only trace quantities of sulfur and ash, well below any established fuel content limits for liquid fuels. The ULSD fired in the CTG and emergency engines will have a sulfur content no greater than the 0.0015% by weight limit applicable on and after July 1, 2018; there is no applicable ash limit for ULSD.

3.2.4 Visible Emissions

Regulations at 310 CMR 7.06(1)(b) state that no emissions of non-H_2O vapor visible emissions (opacity) from fuel burning equipment shall exceed 20% opacity for a period in excess of two minutes during any one hour, provided that at no time during that two-minute period shall the opacity exceed 40%. The CTG and emergency engines will readily comply with this standard.

3.2.5 Dust, Odor, Construction and Demolition

Regulations at 310 CMR 7.09 establish that construction or demolition of an industrial, commercial or institutional building may not cause or contribute to a condition of air pollution. MassDEP must be notified in writing at least 10 working days prior to initiation of construction or demolition. Areas where construction or demolition takes place must be treated as necessary to prevent excessive emissions of particulate matter, including seeding, paving, covering, wetting or otherwise treating such areas. In addition, construction or demolition materials must be handled, transported, and stored in a way that does not cause or contribute to a condition of air pollution. Finally, if construction or demolition involves a structure containing friable asbestos material, additional requirements under 310 CMR 7.02 and 310 CMR 7.15 apply, which will be met if any asbestos is discovered during demolition.

The Project will comply with the notification and work practice requirements of 310 CMR 7.09. Specific measures expected to be taken during construction of the new structures include:

- watering or irrigation of the ground surface until it is moist;
- soil stabilization using vegetative cover, mulch, riprap, or pavement or cover soil surfaces as appropriate; and
- installation of wind breaks to reduce the wind velocity across exposed soil surfaces.

As a general practice, no large surface spray painting will be used during construction. Off-site fabrication of structural steel and other components will be used to virtually eliminate almost all sand blasting and prime coat painting operations at the site. Any sand blasting operations that may be required at the site will use containment or "dustless" systems.

3.2.6 Noise

Regulations at 310 CMR 7.10 prohibit the willful or neglectful creation of unnecessary noise emissions from sound-producing equipment. This requirement applies to equipment that may be fitted with enclosures or other sound-suppressing devices, or that can be operated in a manner so as to suppress sound, including construction and demolition equipment, and industrial and commercial sound sources.

The proposed Project will comply with the requirements of 310 CMR 7.10. Canal 3 will employ a number of sound mitigation measures to minimize operational noise. A detailed analysis of existing baseline noise levels and projected impacts after completion of the Project is provided in Section 7.

3.2.7 Source Registration

The owner or operator of any facility exceeding the applicability thresholds at 310 CMR 7.12 must submit a source registration to MassDEP. Facilities must submit a source registration annually if they are required to obtain an operating permit under 310 CMR 7.00: Appendix C, or if their actual emissions of NO_x or VOC are equal to or greater than 25 tpy. The Station currently reports its emissions under 310 CMR 7.12 annually. The Project's proposed emission sources will be added to the Station's source registration emissions report in the first year after their initial operation.

3.2.8 Stack Testing

Regulations at 310 CMR 7.13 establish the manner in which stack testing of emission sources must be performed, when MassDEP determines that testing is required. Testing must be performed in accordance with a test protocol approved by MassDEP, and must be conducted by a person knowledgeable in stack testing. Testing must be conducted in the presence of a MassDEP official when deemed necessary, and test results must submitted to MassDEP on a schedule agreed upon in the approved test protocol. Owners or operators of equipment for which stack testing is required must provide appropriate accommodations, including access to suitable sampling locations, installation of sampling ports at locations representative of the overall exhaust flow, ladders and platforms to support test personnel, a suitable power source for test equipment, and other reasonable facilities as needed.

The Project will comply with the requirements of 310 CMR 7.13. The simple-cycle combustion turbine is required to conduct performance testing under the federal NSPS requirements of 40 CFR 60. Provisions for stack testing of the Project's other air emission sources will be made as deemed necessary by MassDEP.

3.2.9 Monitoring Devices and Reports

Regulations at 310 CMR 7.14 require air emission sources, upon request by MassDEP, to install, maintain and operate emission monitoring devices of a design and installation approved by MassDEP, and to submit periodic emission reports to MassDEP. The CTG is already required to install and operate a CEMS under the provisions of 40 CFR Parts 60 and 75. Canal 3 will provide CEMS design and installation information to MassDEP once a final equipment vendor has been selected.

3.2.10 NO_x Reasonably Available Control Technology

Regulations at 310 CMR 7.19 establish Reasonably Available Control Technology (RACT) for sources with uncontrolled potential emissions of NO_x greater than or equal to 50 tpy. RACT is the application of control technology that is reasonably available and results in the lowest emission limit that is both technologically and economically feasible for a particular source. The requirements of 310 CMR 7.19 do not apply to sources that obtain a plan approval under 310 CMR 7.02 that establishes BACT or LAER to be no less stringent than RACT as defined in 310 CMR 7.19 at the time of plan approval. As detailed in Section 4 of this application, LAER controls for NO_x emissions will be installed on the CTG to achieve emissions that are well below the applicable limits under 310 CMR 7.19.

3.2.11 Massachusetts CO_2 Budget Trading Program/Regional Greenhouse Gas Initiative

Regulations at 310 CMR 7.70 establish the Massachusetts CO_2 Budget Trading Program, which requires electric generating units equal to or greater than 25 MW to hold sufficient CO_2 allowances to cover actual emissions. 310 CMR 7.70 implements the Regional Greenhouse Gas Initiative (RGGI). RGGI is a cooperative effort of nine Northeast and Mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont) to implement a regional cap-and-trade program to control CO_2 emissions from power plants. Affected sources must submit an emission control plan and a monitoring plan for CO_2 emissions. In general, emission units already required to monitor CO_2 emissions in accordance with 40 CFR 75 will meet the monitoring requirements of 310 CMR 7.70. Affected sources must designate an authorized account representative, and emission control plans must be submitted to MassDEP at least 12 months before the date an affected source commences operation.

The Project will comply with the requirements of 310 CMR 7.70.

3.2.12 Massachusetts Greenhouse Gas Reporting

Massachusetts has established a GHG reporting and verification program under 310 CMR 7.71. This regulation applies to facilities that are required to report air emissions to MassDEP under the operating permit program at 310 CMR 7.00: Appendix C and had stationary emission sources that emitted GHGs during the previous calendar year; or that have actual emissions in excess of 5,000 tpy of CO_{2e}; or that were subject to the requirements of 310 CMR 7.71 in any previous year. The Station currently reports its GHG emissions under 310 CMR 7.71 annually. The proposed CTG will be added to the Station's GHG emissions report in the first year after its initial operation.

3.2.13 *Sulfur Hexafluoride*

Massachusetts regulates sulfur hexafluoride (SF_6) emissions from gas-insulated switchgear (GIS) under 310 CMR 7.72. The project will include SF_6 as an insulating gas in a new Generator Circuit Breaker. The new Generator Circuit Breaker will contain a nominal quantity of 25 pounds of SF_6. The Project will comply with the applicable requirements of 310 CMR 7.72, including representation that new GIS has an annual leakage rate not to exceed 1.0%.

4.0 LOWEST ACHIEVABLE EMISSION RATE ANALYSIS

The Appendix A/NNSR LAER analysis applies exclusively to NO_x emissions, as discussed in Section 3.1.2.

Section 4.1 discusses the LAER analysis approach, followed by the LAER analysis for the CTG (Section 4.2), the emergency diesel generator (Section 4.3), and the emergency diesel fire pump (Section 4.4).

4.1 LAER Analysis Approach

LAER is defined in Appendix A, as the more stringent of the following:

1. the most stringent emissions limitation that is contained in any State Implementation Plan (SIP) for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or,
2. the most stringent emissions limitation that is achieved in practice by such class or category of stationary source.

In no event shall a LAER emission limitation allow a new source to emit a subject air contaminant in excess of the amount permitted under any applicable emission standard under 310 CMR or 40 CFR. LAER is expressed as an emission rate and may be achieved from one, or a combination of, the following emission controls:

- A change in raw materials where substitution to a lower-emitting raw material may be technically feasible. For the Project, the “raw material” would be the fuel combusted in the combustion turbine. The combustion turbine will be fired with natural gas as the primary fuel with backup firing of ULSD.
- Process modifications where a change in the process may result in lower emissions. For the Project, the “process” is the combustion turbine. The proposed H-Class turbine will utilize state-of-the-art efficient combustion technology to minimize the formation of NO_x emissions as combustion byproducts.
- Add-on pollution control equipment to capture and reduce air pollutant emissions. The Project will install and operate SCR to control NO_x emissions from the CTG. This is the most efficient add-on pollution control available to reduce NO_x from combustion turbine projects.

To determine the most stringent emission limitation as defined above, several sources were utilized including recently issued preconstruction permits for other simple-cycle combustion sources, USEPA’s RACT/BACT/LAER Clearinghouse (RBLC) database, and individual state agency permit databases. This analysis for NO_x follows the guidelines presented above.

4.2 LAER ANALYSIS – COMBUSTION TURBINE

In combustion turbines, NO_x is formed during the combustion of fuel and is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric N_2 is oxidized at high temperatures to produce nitrogen oxide (NO), NO_2, and other oxides of nitrogen. The major factors influencing the formation of thermal NO_x are peak flame temperatures, availability of O_2 at peak flame temperatures, and residence time within the combustion zone. Fuel-related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. Fuel-related NO_x is generally minimal for natural gas combustion and, therefore, NO_x formation from combustion of natural gas is due mostly to thermal NO_x formation. ULSD contains a small amount of chemically bound nitrogen and NO_x formation from combustion of ULSD is due to both thermal and fuel NO_x formation.

Reduction in thermal NO_x formation can be achieved using combustion controls, and flue gas treatment can further reduce NO_x emissions to the atmosphere. Available combustion controls include H_2O or steam injection and low-emission combustors. Modern CTGs generally use DLN combustors for natural gas firing. In these type of combustors, natural gas and air are pre-mixed prior to combustion. DLN combustors are designed to operate below the stoichiometric ratio, thereby reducing the thermal NO_x formation within the combustion chamber by reducing peak flame temperatures. For ULSD firing, H_2O injection (in the form of liquid or steam) is typically used to minimize NO_x emissions by also limiting peak flame temperatures.

4.2.1 Evaluation of Emission Limiting Measures

4.2.1.1 Change in Raw Materials

The raw material for the Project is the fuel combusted in the CTG. Natural gas has been selected as the primary fuel for the Project, and natural gas is the lowest NO_x emitting fuel available. In order to ensure fuel availability at all times, limited firing of ULSD will occur when natural gas is not available. The reasons why firing natural gas as the sole fuel is not feasible for the Project, and the proposed restrictions for firing of ULSD, are discussed in detail in Section 5.0.

4.2.1.2 Process Modifications

The process is the proposed simple-cycle CTG. A modification to the process would be a change in the CTG design to limit NO_x emissions from the unit. The Project is proposing to utilize DLN combustors during gas firing and water injection during ULSD firing to minimize NO_x formation during the combustion process. These are the only known process modifications available for a large utility-scale simple-cycle combustion turbine.

A process modification available for small-scale combustion turbines is catalytic combustion. Kawasaki markets combustion turbines equipped with catalytic combustors named K-Lean™ (formerly XONON). Kawasaki is the only manufacturer that offers catalytic combustors and its largest combustion turbine is 18 MW. Due to size limitations, K-Lean™ was determined to be technically infeasible for the Project.

4.2.1.3 Add-on Controls

Available add-on pollution controls to reduce NO_x from combustion sources include the following.

- *SCR*: This is a catalytic reduction technology using NH_3 as a reagent that has been in widespread use on new simple-cycle turbines. SCR is widely recognized as the most stringent available control technology for NO_x emissions from simple-cycle turbines.
- *DLN Combustion*: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing, which limits NO_x formation by reducing peak flame temperatures. DLN is generally used in combination with SCR.
- *Water or Steam Injection*: H_2O or steam injection has been historically used for both gas- and oil-fired turbines, but for new turbines, H_2O or steam injection is generally only used for liquid-fuel firing. H_2O or steam injection is less effective than DLN, but DLN combustion cannot be used for liquid fuels.
- *SNCR*: This is selective non-catalytic reduction technology using NH_3 or urea as a reagent that is injected into the hot exhaust gases. SNCR is widely used as a retrofit technology for steam-generating boilers but has never been applied to control NO_x emissions from simple-cycle turbines.
- *EMx™*: This is an oxidation/absorption technology using hydrogen (H_2) or methane (CH_4) as a reactant.

SNCR and EMx™ were determined to be not technically feasible and unable to achieve further reductions than the NO_x reduction achieved by SCR. Furthermore, neither of these technologies has been applied to a simple-cycle combustion turbine. SNCR requires an exhaust gas temperature between 1,600°F and 2,100°F and typically achieves NO_x reductions of 50% or less. The exhaust gas temperature from the proposed CTG is below 1,225°F; therefore, SNCR is not technically feasible for the Project. EMx™ utilizes a catalyst that is coated with potassium carbonate to react with NO_x to form CO_2, potassium nitrite, and potassium nitrate; H_2 is used to regenerate the catalyst when it becomes saturated with the products of reaction. The maximum operating temperature range for EMx™ is 750°F with an optimal range between 500°F - 700°F. Unlike SCR, which is a passive reactor with a single reagent (NH_3), EMx™ is a complicated technology with numerous moving parts and multiple sections that are on or off-line at any given time due to the need to regenerate with H_2 in an O_2-free environment. This complexity reduces the reliability of EMx™ as compared to SCR. Furthermore, EMx™ technology has never been installed on a turbine larger than 43 MW, has never been installed on a simple-cycle combustion turbine, and has not demonstrated NO_x emission levels lower than SCR. For these reasons, EMx™ was eliminated as technically infeasible for the Project.

DLN combustors during natural gas firing, H_2O injection during ULSD firing, and SCR are all technically feasible for the proposed CTG and in combination represent the top-level of control; therefore, these control technologies have been selected to achieve LAER.

4.2.2 Most Stringent Emission Limitation in any SIP

A review of emission limits in SIPs did not identify any NO_x emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. Although not incorporated into the Massachusetts SIP, MassDEP established BACT Guidelines (June 2011) for new combustion sources, including simple-cycle combustion turbines. The NO_x emission limits for simple-cycle combustion turbines in the MassDEP BACT guidelines are 2.5 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing.

4.2.3 Most Stringent Emission Limitations Achieved in Practice

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify the lowest permitted NO_x limits for natural gas and ULSD-fired simple-cycle CTGs. The details of this review are presented in Appendix D, Table D-1.

While a number of the simple-cycle CTGs listed in Table D-1 are permitted without SCR, there are simple-cycle CTGs permitted with SCR at 2.5 ppmvdc for natural gas firing. The value of 2.5 ppmvdc of NO_x is the lowest limit identified for a simple-cycle combustion turbine for natural gas firing. This limit has been achieved in practice at multiple locations, including at the Braintree Electric Watson Station in Massachusetts. The lowest permitted NO_x emission limit for any size combustion turbine firing ULSD is 3.5 ppmvdc for a GE LMS-100 CTG at the Gowanus Generating Station. However, the GE LMS-100 peaking turbine at Gowanus Generating Station has not yet been constructed and it is not believed that this project is moving forward. Also, the Troutdale Energy Center in Multnomah, Oregon is permitted at 3.8 ppmvdc for oil firing for two GE LMS-100 units. The Troutdale project is currently undergoing a contested Oregon Department of Energy siting process, and has not commenced construction. Therefore, these emission levels for oil firing of 3.5 ppmvdc and 3.8 ppmvdc have not been demonstrated in practice. The simple-cycle CTGs with permitted limits below 9 ppmvdc for natural gas firing and 42 ppmvdc for ULSD firing are all are equipped with the same package of emission controls: DLN combustors or H_2O injection for natural gas firing, H_2O injection for ULSD firing, and SCR for both fuels.

4.2.4 Selection of LAER

Canal 3 proposes that NO_x LAER be 2.5 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing. The proposed limit for natural gas firing is equal to the lowest limit permitted for a simple-cycle CTG. The proposed limit for ULSD firing represents an 88% reduction by the SCR (based upon a NO_x rate from the CTG of 42 ppmvdc) and the level deemed technically achievable given the size of the CTG and the required exhaust cooling system. These proposed limits will be achieved through the application of DLN burners during natural gas firing, H_2O injection during ULSD firing and SCR for both fuels.

4.3 LAER ANALYSIS – EMERGENCY DIESEL GENERATOR ENGINE

In diesel generator engines, NO_x is formed during the combustion of fuel and is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric N_2 is oxidized at high temperatures to produce NO, NO_2, and other oxides of nitrogen. The major factors influencing the formation of thermal NO_x are peak flame temperatures, availability of O_2 at peak flame temperatures, and residence time within the combustion zone. Fuel-related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. ULSD contains a small amount of chemically bound nitrogen and NO_x formation from combustion of ULSD is due to both thermal and fuel NO_x formation.

Manufacturers of stationary diesel engines have developed engine design advances to reduce NO_x formation using combustion control techniques. These developments have allowed new engines used for stationary emergency applications to meet applicable USEPA NSPS, as discussed in Section 3.1.4.3.

4.3.1 Evaluation of Emission Limiting Measures

4.3.1.1 Change in Raw Materials

The raw material for the emergency engines is the fuel. It is critical for emergency engines to have their own stand-alone fuel source in the event that the emergency includes disruption of fuel from an outside source, such as natural gas. The primary purpose of the emergency generator engine is to be able to safely shut the plant down in the event of an electric power outage. So in order to maintain this important equipment protection function, ULSD, which can be stored in a small tank adjacent to the emergency generator, is the fuel of choice.

4.3.1.2 Process Modifications

Low-NO_x engine design is the only known process modification that can be made to reduce NO_x emissions from a diesel engine.

4.3.1.3 Add-on Controls

SCR is a technically feasible option for non-emergency applications to control NO_x emissions but there are no known emergency diesel engines that are equipped with SCR. SCR can normally achieve 90% removal of NO_x emissions under steady-state operating conditions. However, the emergency generator engine will be used only for short periods of time for readiness testing and facility shutdowns in an actual emergency. For an SCR to operate properly, the catalyst must reach and maintain its minimum operating temperature. For the type of operation expected for the emergency generator engine, SCR has not been demonstrated in practice on a comparably sized unit and it is not expected that an SCR will achieve meaningful reductions and, therefore, it was eliminated as technically infeasible for the Project.

4.3.2 Most Stringent Emission Limitation in Any State Implementation Plan

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require new emergency engines to meet the applicable emission standards under 40 CFR 89. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in SIPs did not identify any NO_x emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89.

4.3.3 Most Stringent Emission Limitations Achieved in Practice

A review of recent NO_x emission limits for emergency generator diesel engines installed as part of a large combustion turbine-based generating projects, as summarized in Table D-9 in Appendix D, show that these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR Part 89. No limits were found that required installation of add-on pollution controls for emergency generator diesel engines.

As discussed in Section 2.3.1, emergency generator engines are now commercially available that meet the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039.104(g), Table 1, which is 3.5 g/kW-hr of NO_x.

4.3.4 Selection of LAER

NRG proposes that NO_x LAER for the emergency generator diesel engine be the applicable emission limitation for this class of emergency engine under the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039.104(g), Table 1, which is 3.5 g/kW-hr of NO_x. This meets the most stringent limit achieved in practice for an emergency generator diesel engine and is well below the limit under 40 CFR 60 NSPS Subpart IIII of 6.4 g/kW-hr mechanical (NO_x plus NMHC).

4.4 LAER ANALYSIS – EMERGENCY DIESEL FIRE PUMP ENGINE

In diesel fire pump engines, NO_x is formed during the combustion of fuel and is generally classified as either thermal NO_x or fuel-related NO_x. Thermal NO_x results when atmospheric N_2 is oxidized at high temperatures to produce NO, NO_2, and other oxides of nitrogen. The major factors influencing the formation of thermal NO_x are peak flame temperatures, availability of O_2 at peak flame temperatures, and residence time within the combustion zone. Fuel-related NO_x is formed from the oxidation of chemically bound nitrogen in the fuel. ULSD contains a small amount of chemically bound nitrogen and NO_x formation from combustion of ULSD is due to both thermal and fuel NO_x formation.

Manufacturers of stationary diesel engines have developed engine design advances to reduce NOx formation using combustion control techniques. These developments have allowed new engines used for stationary emergency applications to meet applicable USEPA NSPS, as discussed in Section 3.1.4.3.

4.4.1 Evaluation of Emission Limiting Measures

4.4.1.1 Change in Raw Materials

The raw material for the emergency fire pump engine is the fuel. It is critical for emergency engines to have their own stand-alone fuel source in the event that the emergency includes disruption of fuel from an outside source, such as natural gas. The purpose of the emergency fire pump engine is to provide firefighting capabilities during a fire. So in order to maintain this important equipment protection function, ULSD, which can be stored in a small tank adjacent to the emergency fire pump engine, is the fuel of choice.

4.4.1.2 Process Modifications

Low-NO_x engine design is the only known process modification that can be made to reduce NO_x emissions from a diesel engine.

4.4.1.3 Add-on Controls

SCR is a technically feasible option for non-emergency applications to control NO_x emissions but there are no known emergency diesel fire pump engines that are equipped with SCR. SCR can normally achieve 90% removal of NO_x emissions under steady-state operating conditions. However, the emergency diesel fire pump engine will be used for short periods of time for readiness testing or in an actual emergency. For an SCR to operate properly, the catalyst must reach and maintain its minimum operating temperature. For the type of operation expected for the emergency diesel fire pump engine, SCR has not been demonstrated in practice on a comparably sized unit and it is not expected that an SCR will achieve meaningful reductions and, therefore, it was eliminated as technically infeasible.

4.4.2 Most Stringent Emission Limitation in Any State Implementation Plan

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require new emergency engines to meet the applicable emission standards under 40 CFR 60 Subpart IIII. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in SIPs did not identify any NO_x emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89 or 40 CFR 60 Subpart IIII.

4.4.3 Most Stringent Emission Limitations Achieved in Practice

A review of recent NO_x emission limits for emergency diesel fire pump diesel engines installed as part of a large combustion turbine-based generating projects, as summarized in Table D-10 in Appendix D, show that these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR 60 Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency generator diesel engines.

4.4.4 Selection of LAER

Canal 3 proposes that NO_x LAER for the emergency fire pump diesel engine be the applicable emission limitation for non-road engines under NSPS Subpart IIII. This meets the most stringent limit achieved in practice for an emergency fire pump diesel engine. The applicable limit under NSPS Subpart IIII for a new emergency fire pump engine rated at 135 brake-horsepower is 4.0 g/kW-hr mechanical (NO_x plus NMHC).

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Massachusetts Air Pollution Control Regulations (310 CMR 7.00) require application of BACT for all Plan Approvals. The pollutants to which MassDEP BACT applies are not determined by potential emissions, but rather are based on the pollutants that MassDEP regulates under ambient air quality standards and emission regulations.

The BACT discussion begins with a description of the overall BACT approach (Section 5.1), followed by pollutant-specific sections for the CTG (fuels, NO_x, VOC, CO, PM/PM_{10}/$PM_{2.5}$, SO_2/H_2SO_4, GHG, NH_3, and formaldehyde; Sections 5.2.1 - 5.2.9, respectively). Then, BACT Sections are presented for the emergency diesel generator (fuels, NO_x, CO/VOC, PM/PM_{10}/$PM_{2.5,}$ SO_2/H_2SO_4, and GHG; Sections 5.3.1 - 5.3.6, respectively) and then for the emergency diesel fire pump (fuels, NO_x, CO/VOC, PM/PM_{10}/$PM_{2.5}$, SO_2/H_2SO_4, and GHG; Sections 5.4.1- 5.4.6, respectively).

5.1 BACT ANALYSIS APPROACH

A top-down analysis was employed that satisfies the requirements of Massachusetts BACT and accompanying policies. In accordance with 310 CMR 7.02, BACT is defined as the following:

> *"…means an emission limitation based on the maximum degree of reduction of any regulated air contaminant emitted from or which results from any regulated facility which the Department, on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques for control of each such contaminant. The best available control technology determination shall not allow emissions in excess of any emission standard established under the New Source Performance Standards, National Emission Standards for Hazardous Air Pollutants or under any other applicable section of 310 CMR 7.00, and may include a design feature, equipment specification, work practice, operating standard, or combination thereof."*

MassDEP has issued "Best Available Control Technology (BACT) Guidance" (June 2011), which states that the MassDEP's top-down BACT approach is based upon USEPA's "Top Down BACT Policy" (1987) that was further documented in USEPA's draft "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" (October 1990). In those documents, the USEPA describes a five-step "top-down" process to identify BACT. This five-step process has been followed to identify BACT for all pollutants subject to PSD and 310 CMR 7.02 BACT. The top-down BACT process involves the following five-steps:

(1) identify all control technologies;
(2) eliminate technically infeasible options;
(3) rank remaining control technologies by control effectiveness;
(4) evaluate most effective controls and documents results; and,
(5) select BACT.

Following is a description of the steps followed for each BACT-subject pollutant for each emission source.

5.1.1 Step 1: Identification of Control Technology Options

The first step in a BACT analysis is the identification of available control technologies, including an evaluation of transferable and innovative control measures that may not have been previously applied to the source type under analysis. For emission sources with a large number of recent control technology determinations, such as those proposed for the Project, the available control technologies can be identified from the various agency reviews of these projects. A review was conducted of recent technical determinations made by USEPA and various state air agencies to identify available control technology options for each proposed emission source and each subject pollutant.

5.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Once all control technology options are identified, each is evaluated to determine if it is technically feasible for the proposed emission source. This determination is made on a case-by-case basis in accordance with regulatory guidance. A control option may be shown to be technically infeasible by documenting that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Per regulatory guidance, a permit requiring the application of a technology is sufficient justification to assume the technical feasibility of that technology. Following this guidance, this analysis has focused on technologies that have been demonstrated in practice based upon recent determinations and reviewed alternative technologies to assess their capability to achieve a greater emission reduction than the approved technologies.

5.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

After technically infeasible control technologies have been eliminated, the remaining control options are ranked by control effectiveness. The minimum requirement for a BACT proposal is an option that meets federal NSPS limits or other minimum state or local requirements, such as MassDEP emission standards.

5.1.4 Step 4: Evaluation of Most Effective Controls

The USEPA's draft "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" states that:

> *"if the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT."*

In USEPA's guidance document "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011), it states that "the top-ranked option should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top-ranked technology is not 'achievable' in that case." Accordingly, an evaluation of energy, environmental, or economic impacts is applied only when an applicant wants to demonstrate that the top-ranked option is not achievable.

Based upon this guidance, when the top-case BACT option was determined to be achievable and was selected for the Project, an evaluation of energy, environmental, or economic impacts in general was not considered. The exception to this is that any collateral environmental impacts associated with a proposed top-case option are addressed only to the extent that such collateral impacts would be deemed unacceptable, and thus rule out a proposed top-case option as BACT.

In order to identify the most effective control for each subject emission source and pollutant, a search was performed of the USEPA's RBLC database as well as permits issued by the MassDEP and other states, to the extent available. Information was compiled for each emission source, focusing on projects permitted in the last five years. Older precedents were included on a pollutant-specific basis to identify the most stringent permitted emission levels achieved in practice on a pollutant-by-pollutant basis. Appendix D provides a summary of BACT precedents identified for large simple-cycle combustion turbine projects.

Additional references for purposes of MassDEP BACT are presumptive "top-case" limits established by MassDEP. Presumptive BACT limits for simple-cycle turbines for both natural gas and liquid fuel are found on the MassDEP website (http://www.mass.gov/eea/docs/dep/air/approvals/bactcmb.pdf) (June 2011).

5.1.5 Step 5: Selection of BACT

If there is only a single technically feasible option, or if the top-ranked control option is proposed, then no further analysis was conducted other than a check of potentially unacceptable collateral environmental impacts as discussed above. If two or more technically feasible options were identified, and the most stringent (top) level of control was not proposed, the next three steps (as presented below) were applied to demonstrate that the economic, energy, and environmental impacts of the top-ranked option justified not selecting this option as BACT.

5.1.5.1 Economic Impacts

The economic analysis consists of evaluating the cost-effectiveness of a control technology, on a dollar per ton of pollution removed basis. Annual emissions with a control option are subtracted from base-case emissions to calculate tons of pollutant controlled. The base case may be uncontrolled emissions or the maximum emission rate allowed by regulation (such as an NSPS limit). Annual costs are calculated by the sum of operation and maintenance costs plus the annualized capital cost of the control option. Operating and maintenance costs may take into account a reduction in the output capacity or reliability of a unit. The cost-effectiveness (dollars per ton of pollutant removed) of a control option is the annual cost (dollars per year) divided by the annual reduction in pollutant emissions (tpy). If the calculated cost effectiveness is deemed too high, then a control option may be eliminated from the remainder of the BACT analysis for economic reasons. If the most effective control option is proposed, or if there are no technically feasible control options, an economic analysis is not required.

5.1.5.2 Energy Impacts

The consumption of energy by the control option itself is a quantifiable energy impact. These impacts can be quantified by either an increase in fuel consumption due to reduced efficiency or fuel consumption to power the control equipment.

5.1.5.3 Environmental Impacts

The environmental impact analysis concentrates on other impacts such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of additional regulated or unregulated pollutants. Collateral increases or decreases in air pollutant emissions of other criteria or non-criteria pollutants may occur with a control option and should be evaluated. These additional impacts are identified and qualitatively and/or quantitatively evaluated as appropriate.

5.2 COMBUSTION TURBINE

5.2.1 Fuels

The first step in evaluating BACT is to evaluate changes in raw materials where substitution to a lower emitting raw material may be technically feasible. For the Project, the "raw material" would be the fuel combusted in the combustion turbine. The selection of the lowest emitting fuel for a combustion source affects emissions of multiple pollutants and, therefore, this review of available fuels is applicable for all BACT-subject pollutants for the Project.

5.2.1.1 Step 1: Identification of Control Technology Options

Available fuel choices for the CTG include the following:

- natural gas as the sole fuel, based on securing a dedicated pipeline supply;
- natural gas as the primary fuel with liquefied natural gas (LNG) as backup; and,
- natural gas as the primary fuel with ULSD as the backup fuel.

5.2.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Natural gas is the cleanest burning fossil fuel and its selection as the primary fuel is the "top case" for emissions reductions that may be achieved through fuel choice. The design of the Project as an on-demand peaking power source that can start and reach full load within 10 minutes requires that a source of fuel be available at all times ("No Notice Service"). The Station currently connects to an AGT interstate natural gas pipeline. The AGT system is highly constrained particularly on the G Lateral where the Project will connect. This means that there is not always sufficient latent capacity to reliably support quick-start capability at the Project. Although AGT does provide No-Notice Service (i.e., firm fixed-contract for uninterruptible supply available at a moment's notice) to some customers, it is fully subscribed by local gas distribution companies who use this service to supply existing firm downstream commitments. Natural gas as a sole fuel source is, therefore, deemed infeasible for purposes of BACT.

The Station does not have a firm-fixed contract for an uninterruptible supply of natural gas. ISO-NE's recent *Winter Reliability Program Update* (September 2015)[3], noted that the region is increasingly reliant on resources with uncertain availability, and that natural gas generating units typically lack firm gas transportation or fuel storage.

In ISO-NE's *2015 Regional Electricity Outlook*[4], ISO-NE discusses the issue of natural gas supply constraints in the regional natural gas transmission system. ISO-NE notes that the natural gas pipeline system is reaching maximum capacity more often and when supplies become constrained, priority goes to residential and commercial customers. Given the location of the Project within New England's natural gas transmission system, it is anticipated that natural gas may not be available at all times based on the current gas pipeline infrastructure, especially (as described below) within 10-minutes of a dispatch notice from ISO-NE. As stated above, No Notice Service via the existing natural gas transmission system is not commercially available and, therefore, such service to the Project is deemed infeasible for purposes of BACT.

The Project's purpose as a source of peaking power supply when electric supplies are needed most by the regional transmission system eliminates the option of relying on interruptible gas as the sole fuel for the CTG. The Project could not fulfill its central function as a backstop for regional power supplies if it could only operate on interruptible gas. Therefore, using interruptible gas as the sole fuel was deemed infeasible and eliminated as an option for the Project. Dual-fuel capability for the Project is necessary because, at times, ULSD will be the only available fuel that can be relied upon when ISO-NE dispatches the Project within 10 minutes to maintain bulk power system reliability.

Securing a dedicated pipeline supply of natural gas to the Station is also not feasible for the Project. Due to regional gas pipeline constraints discussed in the ISO-NE reports referenced above, securing a dedicated pipeline supply of natural gas to the Station site would require major regional infrastructure system improvements that are well beyond the scope a single generation project could undertake. Contemplated and proposed upgrades to the interstate gas pipeline system serving New England are well documented by ISO-NE and others (Raab and Peterson, 2015). Proposed upgrades to the interstate gas pipeline system serving New England, which would enable dedicated natural gas supplies to be available for proposed generation facilities such as the Project, are well beyond the reasonable commercial feasibility of a single generation project to undertake. Therefore, while it is theoretically possible (at some speculative future date) to complete such upgrades to the interstate gas pipeline system serving New England, these upgrades are not achievable in any reasonable time frame to supply the Project with uninterruptable No Notice Service natural gas. Therefore, these interstate pipeline upgrades are deemed technically infeasible for purposes of BACT.

Another potential option that would create a dedicated supply of natural gas to the Project would be installation of LNG storage. Securing the necessary approvals and constructing this LNG storage at the Station site is also not feasible for the Project. A significant concern is the exclusion zone required around LNG storage tanks and whether sufficient space even exists for such an exclusion zone at the Station site. Construction and operation of LNG storage is a major undertaking that changes the fundamental nature of the Project. LNG delivery is typically by large

[3] http://www.iso-ne.com/static-assets/documents/2015/09/final_gillespie_raab_sept2015.pdf
[4] http://www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf

specialized ocean vessels, which would require major infrastructure to unload such vessels and re-vaporize the LNG. The length of time alone to secure approvals for new LNG-related infrastructure, if they could even be obtained at all, would certainly not be possible in any reasonable timeframe that is consistent with this proposal to construct a peaking electric generation facility. Therefore, using LNG as a backup to pipeline natural gas is eliminated as technically infeasible for the Project.

Therefore, the only remaining technically feasible fueling option for the Project is the use of interruptible natural gas as the primary fuel with ULSD as the backup fuel.

5.2.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

The sole technically feasible option for fuels is natural gas as the primary fuel with ULSD as backup fuel.

5.2.1.4 Step 4: Evaluation of Most Effective Controls

Limits achieved in practice for generating units that utilize ULSD as backup fuel include limiting the number of operating hours when the backup fuel can be fired and restrictions on when backup fuel can be fired. The most recent PSD approval issued for an electric generating unit in Massachusetts is for the Pioneer Valley Energy Center. This approval limited backup firing of ULSD to 1440 hours per year and imposed the following restrictions on when ULSD can be fired:

i. The interruptible natural gas supply is curtailed at the Tennessee No. 6 gas terminal hub. A curtailment begins when the owner/operator receives a communication from the owner of the hub informing the owner/operator stating that the natural gas supply will be curtailed, and ends when the owner/operator receives a communication from the owner of the hub stating that the curtailment has ended.

ii. Any equipment (whether on-site or off-site) required to allow the turbine to utilize natural gas has failed.

iii. The owner/operator is commissioning the combined cycle turbine and, pursuant to the turbine manufacturer’s written instructions, the owner/operator is required by the manufacturer to fire ULSD during the commissioning process.

iv. The firing of ULSD is required for emission testing purposes as specified in the PSD permit or as required by the Commonwealth of Massachusetts.

v. Routine maintenance of any equipment requires the owner/operator to fire ULSD.

vi. In order to maintain an appropriate turnover of the on-site fuel oil inventory, the owner/operator can fire ULSD when the age of the oil in the tank is greater than six months. A new waiting period for when oil can be used pursuant to this condition will commence once oil firing is stopped.

5.2.1.5 Step 5: Selection of BACT

The proposed fuel BACT for the Project is the use of natural gas as the primary fuel, with ULSD as the backup fuel. The selection of appropriate conditions on ULSD use is key to the fuels BACT determination.

Establishing appropriate restrictions on ULSD use, consistent with the provisions of BACT, requires that the basic relationship between power demand and fuel purchase be examined. In general, ISO-NE can procure power from generating units such as the Project based on the “Day Ahead” market or the “Real Time” market. The Day Ahead market involves bidding power sales one day prior to when the power would be generated, which also allows fuel purchase arrangements to be made one day in advance. It is much more likely that gas supplies can be successfully arranged for the Project in the Day Ahead market. In contrast, the Real Time market functions on the same day the power is generated. Real Time operation includes resources known as “fast-start generators” participating in the “Ten-Minute Non-Spinning Reserve” (TMNSR) market. This market plays a significant role in ensuring the reliability of the bulk power system since resources with the ability to start-up in 10 minutes can respond quickly to unusual events including: (i) sudden unscheduled outages of both transmission and generation resources; (ii) severe weather events; and, (iii) unexpected losses of renewable resources such as solar or wind power. However, it will typically not be possible for a fast-start generator to purchase natural gas within 10 minutes of being notified of a dispatch by ISO-NE. Since the Project is planning to participate in the TMNSR market (an important regional system need), start up and operation of the Project in Real Time will typically require the use of ULSD until adequate supplies of natural gas can be secured.

Therefore, the proposed fuel BACT for the Project has been developed recognizing the important role real-time dispatch of fast-start generators plays in maintaining the reliability of the bulk power system. Accordingly, natural gas will be fired in the proposed CTG at all times when it is available; however, natural gas will not typically be available within the 10 minute timeframe necessary to meet ISO-NE's TMNSR requirements. When natural gas is not available, the proposed CTG will start on ULSD and will switch over to natural gas as soon as reasonably possible. Given the time frame necessary to procure natural gas in real time, confirm its delivery on the pipeline, and comply with the real time bidding requirements of ISO-NE, it is not expected that a swap over to gas will be possible in less than four hours from the initial dispatch instruction from the system operator. In order to ensure reliable annual service to the region as a fast-start generator, the Project is requesting up to 720 operating hours per year using ULSD.

Natural gas will be deemed unavailable when its supply and/or delivery cannot be contracted for within the timeframe necessary to start the unit or when emergency conditions or scarcity conditions are declared by ISO-NE. ULSD firing will also occur to ensure that the unit is properly maintained and the ULSD quality is high enough to support unit availability and to meet the BACT and LAER emission rates. It is proposed to limit the Project's use of ULSD to any of the following specific conditions.

i) When ISO-NE declares an Emergency, as defined in ISO New England's Operating Procedure No. 21, No. 4, and No. 7, or declares a Scarcity Condition.

ii) When AGT issues a critical notice that disallows increases in nominations from where gas is received on their pipeline system to the point of delivery for the Project.

iii) When gas supplies cannot be procured or delivered at any price or are not available for purchase or delivery within the timeframe required to support operation of the Project. The Project will use all commercially reasonable efforts to switch to natural gas operation as soon as possible without jeopardizing the safety of equipment or operating personnel.

iv) If the Project is operating on natural gas and the supply or delivery is curtailed by the pipeline operator. In this situation, the Project will use all commercially reasonable efforts to switch back to natural gas operation as soon as it is again available without jeopardizing the safety of equipment or operating personnel.

v) Any equipment (whether on-site or off-site) required to allow the turbine to operate on natural gas has failed including a physical blockage of the supply pipeline.

vi) During commissioning when the combustion turbine is required to operate on ULSD pursuant to the turbine manufacturer's written instructions.

vii) For emission testing purposes as specified in the Project's air permit or as required by the Commonwealth of Massachusetts.

viii) During routine maintenance if any equipment requires ULSD operation.

ix) In order to maintain an appropriate turnover of the on-site fuel oil inventory, ULSD can be used when the age of the fuel in the tank is greater than six months. A new waiting period for when ULSD can be used pursuant to this condition will commence once ULSD firing is stopped. ***In addition, the use of ULSD burned pursuant to this condition (ix) will be limited to 4,000,000 gallons per rolling four -year period (rolling calendar years). This corresponds to 160 hours of 100% load operation over four years at the 0°F firing rate on ULSD.***

Additionally, the Project agrees not to operate on ULSD pursuant to conditions (vii), (viii) and (ix) on any day when the air quality index for the area including Sandwich, MA is, or is forecast to be, 101 or greater. ***Fairhaven MA, which is the current AQI tabulation/prediction site closest to Sandwich MA, may be used for the reference AQI value for this condition. AQI is made available through the AIRNow web site at http://airnow.gov/index.cfm?action=airnow.local_city&cityid=74 (or its successor). If the AQI is re-scaled, "101" in this condition shall be replaced by an equivalent value indicating air quality Unhealthy for Sensitive Groups or worse.*** This limitation does not apply to conditions (i) through (vi).

There are no unacceptable collateral environmental impacts associated with use of 720 hours per year of ULSD firing that would preclude its selection as BACT, in combination with use of natural gas as the primary fuel.

5.2.2 NO_x

5.2.2.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed simple-cycle CTG. A modification to the process would be a change in the CTG design to limit the NO_x emissions from the unit. The Project is proposing to utilize DLN combustors during natural gas firing and H_2O injection during ULSD firing to minimize NO_x formation during the combustion process. A process modification available for small-scale combustion turbines is catalytic combustion. Kawasaki markets combustion turbines equipped with catalytic combustors named K-Lean™ (formerly XONON).

Add-on Controls

Available add-on pollution controls to reduce NO_x from combustion sources include the following:

- *SCR*: This is a catalytic reduction technology using NH_3 as a reagent that has been successfully demonstrated on simple-cycle turbines. SCR is widely recognized as the most stringent available control technology for NO_x emissions from simple-cycle turbines.
- *DLN Combustion*: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing, which limit NO_x formation by reducing peak flame temperatures. DLN is generally used in combination with SCR.
- *H_2O or Steam Injection*: H_2O or steam injection has been historically used for both natural gas- and oil-fired turbines, but for new turbines, H_2O or steam injection is generally only used for liquid fuel firing. H_2O or steam injection is less effective than DLN, but DLN combustion cannot be used for liquid fuels.
- *SNCR*: This is selective non-catalytic reduction technology using NH_3 or urea as a reagent that is injected into the hot exhaust gases. SNCR is widely used as a retrofit technology for steam-generating boilers but has never been applied to control NO_x emissions from simple-cycle turbines.
- *EMx™*: This is an oxidation/absorption technology using H_2 or CH_4 as a reactant.

5.2.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Kawasaki is the only manufacturer that offers catalytic combustors and its largest combustion turbine is 18 MW. Due to this size limitation, K-Lean™ was determined to be technically infeasible for the Project.

SNCR and EMx™ were determined to be not technically feasible and unable to exceed the NO_x reduction achieved by SCR. SNCR requires an exhaust gas temperature between 1,600°F and 2,100°F[5] and typically achieves NO_x reductions of 50% or less. The exhaust gas temperature from the proposed CTG is below 1,225°F; therefore, SNCR is not technically feasible for the project. EMx™ utilizes a catalyst that is coated with potassium carbonate to react

[5] http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

with NO_x to form CO_2, potassium nitrite, and potassium nitrate; H_2 is used to regenerate the catalyst when it becomes saturated with the products of reaction. The maximum operating temperature range for EMx™ is 750°F with an optimal range between 500°F - 700°F. Unlike SCR, which is a passive reactor with a single reagent (NH_3), EMx™ is a complicated technology with numerous moving parts and multiple sections that are on or off-line at any given time due to the need to regenerate with H_2 in an O_2-free environment. This complexity reduces the reliability of EMx™ as compared to SCR. Furthermore, EMx™ technology has never been installed on a turbine larger than 43 MW, has never been installed on a simple cycle combustion turbine, and has not demonstrated NO_x emission levels lower than SCR. For these reasons, EMx™ was eliminated as technically infeasible for the Project.

A combination of DLN combustors during natural gas firing, water injection during ULSD firing, and SCR is technically feasible for the proposed CTG and represents the top-level of control; therefore, these control technologies have been selected to achieve LAER and BACT for the Project.

5.2.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

The technically feasible control options include DLN combustors during natural gas firing, H_2O injection during ULSD firing, and SCR for both fuels.

5.2.2.4 Step 4: Evaluation of Most Effective Controls

A search of the USEPA's RBLC and available permits for similar sources was conducted to identify the lowest permitted NO_x limits for natural gas and ULSD-fired simple-cycle CTGs. The details of this review are presented in Appendix D, Table D-1.

While a number of the simple-cycle CTGs, as shown in Table D-1, are permitted without SCR, there are simple-cycle CTGs permitted with SCR at 2.5 ppmvdc for natural gas firing. The value of 2.5 ppmvdc of NO_x is the lowest limit identified for a simple-cycle combustion turbine for gas firing. The lowest permitted NO_x emission limit for any size combustion turbine firing ULSD is 3.5 ppmvdc for a GE LMS-100 CTG at the Gowanus Generating Station. However, the LMS-100 peaking turbine at Gowanus Generating Station has not yet been constructed and it is not believed that this project is moving forward. Also, the Troutdale Energy Center in Multnomah, Oregon is permitted at 3.8 ppmvdc for oil firing for two GE LMS-100 units. The Troutdale project is currently undergoing a contested Oregon Department of Energy siting process, and has not commenced construction. Therefore, the emission levels for oil firing of 3.5 ppmvdc and 3.8 ppmvdc have not been demonstrated in practice. The simple-cycle CTGs with permitted limits below 9 ppmvdc for natural gas firing and 42 ppmvdc for ULSD firing are all equipped with the same package of emission controls: DLN combustors or water injection for natural gas firing, water injection for ULSD firing, and SCR for both fuels.

A review of emission limits in SIPs did not identify any NO_x emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. Although not incorporated into the Massachusetts SIP, the MassDEP's established BACT Guidelines (June 2011) for new combustion sources include simple-cycle combustion turbines. The NO_x emission limits for simple-cycle combustion turbines in the MassDEP BACT guidelines is 2.5 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing.

5.2.2.5 Step 5: Selection of BACT

Canal 3 proposes that NO_x LAER and BACT be 2.5 ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing consistent with the MassDEP BACT guidelines. The proposed limit for natural gas firing is equal to the lowest limit permitted for a simple-cycle CTG of any size and lower than any limit for a comparably sized simple-cycle CTG. The proposed limit for ULSD firing represents an 88% reduction by the SCR (based upon a NO_x emission rate from the CTG of 42 ppmvdc) and the level deemed technically achievable given the size of the CTG and the required exhaust cooling system. These proposed limits will be achieved through the application of DLN burners during natural gas firing, H_2O injection during ULSD firing, and SCR for both fuels.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. With respect to potential collateral environmental impacts of SCR, one impact we have examined is the use and storage of aqueous NH_3 required for the SCR. As documented in Section 6.0, the predicted ambient air quality impacts for (unreacted) NH_3 "slip" emissions from the stack are well below the MassDEP air toxics guidelines. Aqueous NH_3 will be stored in two existing 60,000-gallon aboveground tanks located within individual concrete dikes, each designed to contain of the total volume of each tank. Passive evaporative controls ***(plastic spheres)*** are used inside the dike to control evaporation in the unlikely event of a release. Evaluation of a hypothetical worst-case release indicates that NH_3 concentrations at and outside the Project perimeter will be less than the ERPG-1 level. ERPG-1 is defined as the maximum airborne concentration below which nearly all individuals could be exposed for up to one hour without experiencing other than mild transient adverse health effects or perceiving a clearly defined, objectionable odor. Therefore, the collateral environmental impacts of SCR are considered to be acceptably mitigated.

5.2.3 VOC

5.2.3.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed simple-cycle CTG; CTGs have inherently low VOC emission rates. Emissions of VOC from a CTG occur as a result of incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and H_2O. VOC emissions from the CTG are limited by utilizing good combustion practices to ensure that the fuel is completely combusted.

Add-on Controls

Available add-on pollution controls to reduce VOC from combustion sources include the following:

- *Oxidation Catalyst*: An oxidation catalyst can effectively control some VOC constituents in the CTG exhaust such as formaldehyde. The degree of removal depends on the particular VOC compounds that are present.

Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. The optimal location for VOC control, in the 900°F to 1,100°F temperature range, would be upstream of the SCR.

5.2.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Good combustion practices and an oxidation catalyst are both (and in combination) technically feasible.

5.2.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

The combination of good combustion practices and an oxidation catalyst (in combination) is the top ranked control option.

5.2.3.4 Step 4: Evaluation of Most Effective Controls

The results of the RBLC search and other available permits for VOC BACT/LAER precedents is presented in Appendix D, Table D-2. Based on this search, use of efficient combustion and an oxidation catalyst is the most stringent level of VOC control for simple-cycle gas turbines. Therefore, the use of these controls is considered to represent the most stringent level of VOC control achieved in practice.

The lowest VOC limit for any simple-cycle CTG in Table C-2 is 1.0 ppmvdc during natural gas firing and 3.5 ppmvdc during ULSD firing for an F-class CTG. There are no known permitted H-class CTGs in simple-cycle configuration. The projects with VOC limits less than 2 ppmvdc have not yet begun operation and, therefore, the lowest VOC emission rate achieved in practice is 2 ppmvdc.

A review of emission limits in SIPs did not identify any VOC emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. The MassDEP's BACT Guidelines for new simple-cycle CTGs list VOC emission limits of 2.5 ppmvdc for natural gas firing and 4.5 ppmvdc for ULSD firing.

5.2.3.5 Step 5: Selection of BACT

The Project is proposing to use the most stringent available control equipment for VOC, good combustion practices and an oxidation catalyst. The proposed VOC BACT emission rates are 2.0 ppmvdc for natural gas firing and 2.0 ppmvdc for ULSD firing. The proposed natural gas limit of 2.0 ppmvdc is equal to the lowest emission limit achieved in practice for a large simple-cycle CTG and the proposed ULSD limit of 2.0 ppmvdc would be the lowest limit of any simple-cycle CTG for oil firing.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with use of an oxidation catalyst.

5.2.4 CO

5.2.4.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed simple-cycle CTG; CTGs have inherently low CO emission rates. Emissions of CO from a CTG occur as a result of incomplete combustion of organic compounds within the fuel. In an ideal combustion process, all carbon and hydrogen contained within the fuel would be oxidized to form CO_2 and H_2O. CO emissions from the unit are limited by utilizing good combustion practices to ensure that the fuel is completely combusted.

Add-on Controls

Available add-on pollution controls to reduce CO from combustion sources include the following:

- *Oxidation Catalyst*: An oxidation catalyst can effectively control CO in the CTG exhaust.

Oxidation catalyst systems consist of a passive reactor comprised of a grid of metal panels with a platinum catalyst. The optimal location for CO control, in the 900°F to 1,100°F temperature range, would be upstream of the SCR.

5.2.4.2 Step 2: Identification of Technically Infeasible Control Technology Options

Good combustion practices and an oxidation catalyst are both (and in combination) technically feasible.

5.2.4.3 Step 3: Ranking of Technically Feasible Control Technology Options

The combination of good combustion practices and an oxidation catalyst (in combination) is the top-ranked control option.

5.2.4.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for CO BACT/LAER precedents are presented in Appendix D, Table D-3. Based on this search, use of an oxidation catalyst is the most stringent level of CO control for natural gas-fired and dual-fuel combustion turbines. Therefore, the use of an oxidation catalyst is considered to represent the most stringent level of CO control achieved in practice.

The lowest CO limits for any project presented in Table D-3 are 4.0 ppmvdc for natural gas firing and 8.0 ppmvdc for oil firing for an F-class CTG. There are no known permitted H-class CTGs in simple-cycle configuration.

A review of emission limits in SIPs did not identify any CO emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. The MassDEP's BACT Guidelines for new simple-cycle CTGs stipulate a CO emission limit of 5.0 ppmvdc for both natural gas and oil firing. This is based on the limits demonstrated in practice for the Trent 60 units at the Braintree Electric Watson Station.

5.2.4.5 Step 5: Selection of BACT

The Project is proposing CO BACT emission limits of ***3.5*** ppmvdc for natural gas firing and 5.0 ppmvdc for ULSD firing. This level of emissions will be achieved via good combustion control and an oxidation catalyst. The proposed natural gas limit is ***more stringent than the*** most stringent limit identified for a simple-cycle CTG. The proposed ULSD limit is more stringent than the most stringent limit identified for a simple-cycle CTG firing ULSD and equivalent to the MassDEP's BACT Guidelines. Therefore, the proposed CO BACT limits are the most stringent limits identified in any permit or agency regulation or guidance.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with use of an oxidation catalyst.

5.2.5 PM/PM_{10}/$PM_{2.5}$

5.2.5.1 Step 1: Identification of Control Technology Options

Process Modifications

The process is the proposed simple-cycle CTG; CTGs have inherently low PM emission rates. Emissions of PM from combustion can occur as a result of trace inert solids contained in the fuel and products of incomplete combustion, which may agglomerate or condense to form particles. PM emissions from CTGs equipped with SCR can also result from the formation of ammonium salts due to the conversion of SO_2 to sulfur trioxide (SO_3), which is then available to react with NH_3 to form ammonium sulfates. All of the PM emitted from the simple-cycle gas turbines is conservatively assumed to be less than 2.5 microns in diameter. Therefore, PM, PM_{10} and $PM_{2.5}$ emission rates are assumed to be the same.

Add-on Controls

This evaluation did not identify any PM/PM_{10}/$PM_{2.5}$ post-combustion control technologies available for simple-cycle combustion turbines. Post-combustion particulate control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid-fuel boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for combustion turbine operation. There are no known simple-cycle combustion turbine facilities that are equipped with a post-combustion particulate control technology.

5.2.5.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for particulate matter from combustion turbines is to fire clean-burning fuels and ensure good combustion practices.

5.2.5.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of natural gas as the primary fuel, limited firing of ULSD, and good combustion practices are the only technically feasible controls.

5.2.5.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for PM/PM_{10}/$PM_{2.5}$ BACT/LAER precedents are presented in Appendix D, Table D-4. Based on this search, use of clean-burning fuels and good combustion practices are the most stringent available technologies for control of simple-cycle combustion turbine PM emissions.

A review of Table D-4 indicates that the majority of the limits are presented in the units of lb/hr. In order to compare these limits across a range of turbine sizes, the equivalent full-load emission rates in lb/MMBtu were estimated based on available data for each turbine.

One limit in the RBLC (Pio Pico) is presented in the units of lb/MMBtu, at 0.0065 lb/MMBtu for natural gas firing. The natural gas-fired limits (converted to lb/MMBtu at full load) range from 0.004 – 0.04 lb/MMBtu, with the bulk of the limits in the 0.005 – 0.012 lb/MMBtu range. Since most of these limits are expressed in lb/hr, the equivalent lb/MMBtu would increase under part-load conditions.

There are seven projects listed in Table D-4 with BACT determinations for oil firing in simple-cycle turbines. Two of these (in Florida) have PSD BACT limits stated in terms of the fuel sulfur content (ULSD). Two others (Troutdale and Dahlberg) have PM BACT limits expressed in lb/hr, with a calculated lb/MMBtu for full load of 0.03 lb/MMBtu. The other three (Wolverine, Dayton, and Braintree) have specific PM limits in lb/MMBtu for oil firing. Since Wolverine is a black-start combustion turbine for a coal-fired power plant, it is not clear if part-load conditions were taken into account for the limit of 0.03 lb/MMBtu. Dayton's limit of 0.026 lb/MMBtu is qualified as strictly a filterable PM limit by USEPA Method 5, which means this value should be at least doubled to compare it to the other limits that are assumed to include both filterable and condensable fractions, since this is the common way to express a limit for $PM_{2.5}$. The Braintree limit of 15.0 lb/hr and 0.05 lb/MMBtu includes part-load firing, since at full load for the Trent 60, the calculated value would be 0.0275 lb/MMBtu. Note there actually is an eighth duel-fuel project listed in Table D-4 (VMEU Howard Down), but the PM limit listed in RBLC appears to be only the natural gas-fired limit for the Trent 60.

It is important to recognize that the differences in $PM/PM_{10}/PM_{2.5}$ emission limits among various projects are largely due to different emission guarantee philosophies of the various suppliers, and are not believed to be actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions inherently produced by the combustion turbine models. The different emission guarantee philosophies are influenced by the overall uncertainties of the $PM/PM_{10}/PM_{2.5}$ test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the inclusion of condensable particulate emissions in permit limits in the last decade.

A review of emission limits in SIPs did not identify any $PM/PM_{10}/PM_{2.5}$ emission limits for combustion turbines more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT and/or LAER requirements. The MassDEP BACT guidelines do not provide $PM/PM_{10}/PM_{2.5}$ limits as there are no technically feasible add-on pollution controls, and these limits are typically based upon vendor performance guarantees.

5.2.5.5 Step 5: Selection of BACT

Canal 3 is proposing the $PM/PM_{10}/PM_{2.5}$ BACT emission rate to be the CTG vendor performance emissions guarantees, consistent with other permitted projects. As there are no H-class CTGs permitted in simple-cycle configuration, there are no comparable permitted projects to assess these proposed BACT limits.

The Project is proposing BACT $PM/PM_{10}/PM_{2.5}$ limits for natural gas firing of ***0.0073*** lb/MMBtu, not to exceed 18.1 lb/hr, ***at 75% load or greater, and 0.012 lb/MMBtu not to exceed 18.1 lb/hr at less than 75% load down to MECL.*** These values compare favorably with the other natural gas-firing PM BACT precedents in Appendix D, Table D-4.

For ULSD firing, the proposed $PM/PM_{10}/PM_{2.5}$ BACT limits are ***0.026 lb/MMBtu, not to exceed 65.8 lb/hr, at 75% load or greater, and*** 0.046 lb/MMBtu, not to exceed 65.8 lb/hr ***at less than 75% load down to MECL.*** BACT will be achieved with the most stringent available particulate control technologies, which are good combustion practices and limited firing of ULSD as backup fuel. The value of ***0.026*** lb/MMBtu ***for 75% load and above*** compares favorably with the lb/MMBtu full-load equivalent values found in the RBLC for recent BACT determinations, given the different guarantee approaches of different turbine suppliers.

The proposed opacity limit for the CTG for natural gas firing (above MECL) is an opacity level of 5%, with 5-10% opacity allowed for up to 2 minutes per hour. This gas-firing opacity limit is consistent with other recent MassDEP Plan Approvals and PSD permits for combustion turbine units. The proposed opacity limit for the CTG for ULSD (above MECL) is an opacity level of 10%. This is the lowest opacity level guarantee available from GE for the 7HA.02 CTG while firing ULSD. The proposed opacity BACT during startup/shutdown is compliance with the MassDEP opacity/smoke regulations under 7.06(1)(a and b), which is 20% opacity with short exceptions allowed up to 40% opacity.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice ***for an H-class simple cycle turbine***. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed PM/PM_{10}/$PM_{2.5}$ BACT.

5.2.6 SO_2/H_2SO_4

5.2.6.1 Step 1: Identification of Control Technology Options

Process Modifications

Emissions of SO_2/H_2SO_4 are formed from the oxidation of sulfur in the fuel. Normally, all sulfur compounds contained in the fuel will oxidize, with the vast majority initially oxidizing to SO_2 and a smaller percentage to SO_3. Additionally, a portion of the fuel sulfur that initially oxidizes to SO_2 will be subsequently oxidized to SO_3 by the SCR and oxidation catalyst. Due to the high temperature of the CTG exhaust in simple-cycle mode, a relatively significant percentage of the SO_2 is expected to oxidize to SO_3 while passing through the SCR and oxidation catalyst. After being formed, SO_3 and sulfate (SO_4) react to form H_2SO_4 and sulfate particulate. There are no process modifications available to reduce SO_2 and H_2SO_4 emissions from the CTG without compromising the ability to achieve BACT for NO_x and CO and MassDEP BACT for VOC.

Add-on Controls

This evaluation does not identify and rank control technologies as there are no simple-cycle gas turbine post-combustion control technologies available for SO_2/H_2SO_4. Post-combustion SO_2/H_2SO_4 control technologies, such as dry or wet scrubbers that are commonly used on solid-fuel boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create an unacceptable amount of backpressure for turbine operation. Furthermore, the low concentrations of SO_2/H_2SO_4 in the exhaust gas would make further reductions very difficult, if not impossible, to achieve. Canal 3 is not aware of any simple-cycle gas turbine facilities that are equipped with any post-combustion SO_2/H_2SO_4 control technologies.

5.2.6.2 Step 2: Identification of Technically Infeasible Control Technology Options

The only known control option for SO_2/H_2SO_4 from combustion turbines is to fire clean-burning fuels and ensure good combustion practices.

5.2.6.3 Step 3: Ranking of Technically Feasible Control Technology Options

The firing of pipeline-quality natural gas and ULSD as the sole fuels is the only technically feasible control.

5.2.6.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for SO_2/H_2SO_4 BACT precedents are presented in Appendix D, Table D-5. This search confirms that the only technology identified for control of SO_2/H_2SO_4 from combustion turbines is use of low-sulfur fuel. The limits in Table D-5 indicate BACT emissions for SO_2/H_2SO_4 have been typically expressed as a fuel sulfur content limit. A relatively wide range of fuel sulfur content limits was found. The lowest sulfur content in natural gas identified is 0.2 grains per 100 standard cubic feet (gr/100 scf) for the Indeck Wharton project in Texas. This sulfur content limit is well below USEPA's sulfur content limit of 0.5 gr/100 scf for pipeline-quality natural gas as defined in the Acid Rain Program under 40 CFR 72.2. The natural gas sulfur content limit for all other projects identified in Table D-5 is at or above 0.5 gr/100 scf. The lowest oil sulfur content limit identified is 15 ppmw, equivalent to 0.0015 percent by weight (ULSD).

5.2.6.5 Step 5: Selection of BACT

For the sulfur content of natural gas, the USEPA definition of “pipeline natural gas” in 40 CFR 72.2 stipulates a maximum sulfur content of 0.5 gr/100 scf. Canal 3 has reviewed actual sulfur content data from the natural gas supplier and proposes a limit of 0.5 gr/100 scf consistent with USEPA’s definition of “pipeline natural gas.” The backup fuel will be ULSD, which has the lowest sulfur of any available fuel oil at 15 ppmw.

The proposed H_2SO_4 BACT emission rates are 0.0016 lb/MMBtu firing natural gas and 0.0018 lb/MMBtu firing ULSD taking into account a conservative (high) conversion rate of SO_2 to SO_3 by the pollution controls necessary to meet BACT/LAER requirements for NO_x, CO and VOC emissions. ***These H_2SO_4 rates are based on performance data provided by General Electric Company for the 7HA.02 CTG for the Canal 3 configuration.***

The proposed controls represent the top level of control that has been demonstrated to be achievable in practice. Pursuant to USEPA and MassDEP guidance, an evaluation of economic and energy impacts has not been conducted. There are no unacceptable collateral environmental impacts associated with the proposed SO_2/H2SO4 BACT. As documented in Section 6.0, the predicted ambient air quality impacts for SO_2/H_2SO_4 emissions from the stack are well below the NAAQS/MAAQS (SO_2) and the MassDEP air toxics guidelines (H_2SO_4).

5.2.7 GHGs

5.2.7.1 Step 1: Identification of Control Technology Options

The principal GHGs associated with the Project are CO_2, CH_4, and nitrous oxide (N_2O). Because these gases differ in their ability to trap heat, 1 ton of CO_2 in the atmosphere has a different effect on global warming than 1 ton of CH_4 or 1 ton of N_2O. For example, CH_4 and N_2O have 25 times and 298 times the global warming potential of CO_2, respectively, pursuant to 40 CFR 98, Subpart A, Table A-1. GHG emissions from the proposed Project are primarily attributable to combustion of fuels in the simple-cycle gas turbine. There will also be minor fugitive releases of natural gas (primarily CH_4) from valves and flanges associated with the natural gas piping, and of sulfur hexafluoride (SF_6) from the circuit breakers in the substation. By far the greatest proportion of potential GHGs emissions associated with the Project are CO_2 emissions associated with combustion of natural gas and ULSD in the simple-cycle turbine. Trace amounts of CH_4 and N_2O will be emitted during combustion in varying quantities depending on operating conditions, and even more insignificant amounts of SF_6 will be released from the circuit breakers. Even after adjusting for global warming potential, emissions of CH_4, N_2O, and SF_6 are negligible when compared to total CO_2 emissions from the CTG. As such, BACT for the CTG focuses on the options for reducing and controlling emissions of CO_2.

Process Modifications

CO_2 is a product of combusting any carbon-containing fuel, including natural gas and ULSD. All fossil fuel contains significant amounts of carbon. During complete combustion, carbon in the fuel is oxidized into CO_2 via the following reaction:

$$C + O_2 \rightarrow CO_2$$

Full oxidation of carbon in fuel is desirable because CO, a product of partial combustion, has long been a regulated pollutant and because full combustion results in more useful energy. In fact, emission control technologies required for CO emissions (oxidation catalysts) increase CO_2 emissions by oxidizing CO to CO_2. Recent BACT determinations for simple-cycle CTG projects have focused on reducing emissions of CO_2 through high efficiency power generation technology and use of cleaner-burning fuels. Since emissions of CO_2 are directly related to the amount of fuel combusted, an effective means of reducing GHG emissions is through efficient power generation combustion technologies. By utilizing more efficient technology, less fuel is required to produce the same amount of output electricity. The Project is proposing to use an H-class combustion turbine, which is the most efficient combustion turbine in its size range that is commercially available. The proposed Project will have a "Design Base Heat Rate" (new and clean) of approximately 9,241 British thermal units per kilowatt-hour (Btu/kW-hr) (gross), HHV while firing natural gas at full load at ISO conditions, evaporative cooler off. While firing ULSD, this "Design Base Heat Rate" (new and clean) is 9,590 Btu/kW-hr (gross). The emphasis on GHG reductions via efficient combustion is reflected in the recently issued BACT determinations for similar simple-cycle CTG projects as summarized in Appendix D, Table D-6.

Combined-cycle technology can also be considered a type of "process modification," albeit a process modification that changes the fundamental nature of the Project. With combined-cycle technology, a heat recovery steam generator is installed and waste heat is recovered from the fuel gas in the form of steam. This steam is then directed to a steam turbine, which is then used to generate additional power. This increases the efficiency of power generation per unit of fuel combusted. A cooling technology (normally either air cooled condensers or wet cooling towers for new facilities) must also be incorporated to condense the steam as part of the combined-cycle process. However, as discussed below, converting this Project to combined-cycle would change the fundamental nature of the Project, and is not feasible in order for the Project to serve its design function as a quick-starting TMNSR peaking unit.

Another effective method used to reduce GHG emissions is the use of inherently low-emitting fuels. The Project's simple-cycle CTG will combust natural gas as the primary fuel, which is the lowest GHG emitting fossil fuel. Firing of ULSD as the backup fuel will be limited to no more than 720 hours per rolling 12-month period pursuant to the restrictions defined in Section 5.2.1.5.

Add-on Controls

There are limited post-combustion options for controlling CO_2. The USEPA has indicated in the document, *PSD and Title V Permitting Guidance for Greenhouse Gases* (USEPA, 2011), that carbon capture and sequestration (CCS) should be considered in BACT analyses as a technically feasible add-on control option for CO_2. Currently, there are no CTG projects utilizing CCS, and although theoretically feasible, this technology is not commercially available. However, this control option is discussed in greater detail below.

CCS is a relatively new technology that requires three distinct processes:

- isolation of CO_2 from the waste gas stream;
- transportation of the captured CO_2 to a suitable storage location; and,
- safe and secure storage of the captured and delivered CO_2.

The first step in the CCS process is capture of the CO_2 from the process in a form that is suitable for transport. There are several methods that may be used for capturing CO_2 from gas streams, including chemical and physical absorption, cryogenic separation, and membrane separation. Exhaust streams from simple-cycle combustion turbines have relatively low CO_2 concentrations. Only physical and chemical absorption would be considered technically feasible for a high-volume, low-concentration gas stream.

The next step in the CCS process is transportation of the captured CO_2 to a suitable storage location. Currently, development of commercially available CO_2 storage sites is in its infancy. The nearest geological formation that is capable of storing CO_2 is located in New York, more than 200 miles from the Project. However, a carbon storage facility does not exist at this location. New York is an area where the suitability of geological formations for CO_2 storage is being studied by the Midwest Regional Carbon Sequestration Partnership (MRCSP), which is funded by the Department of Energy. While several CO_2 sequestration demonstrations have been initiated under this program, much further development is needed before a commercially available CO_2 sequestration site becomes available near the Project site. Currently, the closest MRCSP CO_2 sequestration site in the development phase is in northern Michigan, over 600 miles from the Project site by land; although this location is not currently operable.

5.2.7.2 Step 2: Identification of Technically Infeasible Control Technology Options

Converting the Project to combined-cycle technology is not feasible to allow the Project to serve its design function as a quick-starting peaking unit. A simple-cycle peaking turbine is not the same "source type" as a conventional combined-cycle unit for BACT purposes. A conventional combined-cycle unit has longer startup times and ramp up rates, and is disadvantaged with respect to the TMNSR market due to the need to warm up the steam-related combined-cycle components. Therefore, conventional combined-cycle technology has been determined to be technically infeasible since it changes the fundamental nature of the Project to a different source type. USEPA top-down BACT guidance and a recent USEPA Environmental Appeals Board (EAB) decision both recognize the fundamental difference between simple-cycle and combined-cycle turbines for the purposes of BACT determinations. The USEPA's draft "New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting" contains the following passage at page B.61 when presenting a sample BACT analysis: "*Due to the lag time required to bring a heat recovery steam generator on line, it is not technically feasible to use a HRSG at the facility. Use of an HRSG in this instance was shown to interfere with the performance of the unit for peaking service, which requires immediate response times for the turbine*." In additional, the EAB Decision in the matter of the Pio Pico Energy Center (PSD Permit No. SD 11-01, PSD Appeal Nos. 12-04 through 12-06, decided August 2, 2013) addressed (among other matters) a challenge that USEPA Region IX clearly erred in eliminating combined-cycle gas turbines in Step 2 of its BACT analysis for greenhouse gases, or that the issue otherwise warrants review or remand. In particular, the EAB concluded that the Region did not define "source type" too narrowly in Step 2. Therefore, this EAB finding supports the fact that simple-cycle and conventional combined-cycle units are fundamentally different source types for purposes of BACT determinations, and conventional combined-cycle technology may be eliminated at Step 2 for a simple-cycle project.

It is recognized that new "quick-start" combined-cycle technologies have been developed (a/k/a "flex plants") that will allow a certain portion of the turbine output to be available in 10 minutes from initial startup, while the steam-cycle portion of the combined-cycle unit warms up. However, in order to be able to bring 300+ MW to the grid in 10 minutes, the total size of the quick-start combined-cycle plant would need to be on the order of 600 MW. Two F-class turbines would be needed to accomplish the same function in the Real Time/TMNSR market. In addition to being substantially larger and more expensive than a single H class simple cycle unit, such a two-unit combined-cycle plant would still operate in a fundamentally different manner.

A single quick-start F-class combined cycle unit would have a nominal output of 300 MW, approximately the same size as the Project, but would only be able to provide approximately 150 MW in 10 minutes. The single F-class "quick-start" unit would cost substantially more than the proposed H-class simple cycle unit, but would only provide about half as much power in 10 minutes as the proposed Project. Either one or two "quick-start" F-class combined-cycle units is considered commercially infeasible, since they would represent fundamental project changes and be highly unlikely to be selected in an ISO-NE FCA due to the substantially higher capital cost and significantly diminished 10-minute generation capability relative to that cost.

With respect to the technical feasibility of CCS, there are no simple-cycle facilities utilizing CCS and this technology is not considered available. As such, this technology has not been demonstrated in practice for simple-cycle facilities or any utility-scale power generating facility in the United States. However, for the purposes of this analysis, CCS is considered technically feasible in accordance with USEPA guidance.

5.2.7.3 Step 3: Ranking of Technically Feasible Control Technology Options

The technically feasible options, ranked in order or effectiveness and achievability, are as follows:

- CCS;
- low emitting fuels; and,
- generating efficiency.

5.2.7.4 Step 4: Evaluation of Most Effective Controls

The results of the search of the RBLC and other available permits for GHG BACT precedents are presented in Appendix D, Table D-6. GHG BACT determinations in Table D-6 are expressed predominantly in units of lb CO_{2e} per MW-hr with two limits on a tpy basis. The energy-based limits are expressed as either “gross” or “net.” Energy units (MW-hr or kW-hr) are more meaningful than mass emission limits since they relate directly to the efficiency of the equipment, which enables comparison of energy efficiency between different projects. Mass emissions are specific to the fuel firing rate of a given project, the number of operating hours, and the carbon content of the fuel, but do not incorporate Project efficiency.

The GHG BACT emission rate must take into account both performance margin and degradation, as follows:

- performance margin accounts for the possibility that the equipment as constructed and installed may not fully achieve the optimal vendor specified design performance; and,
- degradation accounts for the normal wear and tear of the combustion turbine over its useful life and particularly between maintenance overhauls.

The proposed Canal 3 performance margin and degradation factors for the GHG BACT are as follows:

- a performance design margin of 5.0 percent (reflected in GE performance guarantee); and
- an equipment degradation margin of 2.0 percent.

The adjustment factors have a compounding affect so the overall degradation applied from new and clean condition is 7.1% [1.05 × 1.02 = 1.071].

In addition, proposing an H-class CTG that provides the highest efficiency of any available comparably sized CTG. The Project will also be designed to maximize generation efficiency by minimizing sources of internal power consumption. Certain equipment, such as the SCR and oxidation catalysts, do result in pressure drop (and reduced power output). However, the SCR and oxidation catalysts are necessary in order to meet LAER and BACT requirements for criteria pollutants. Within the competing design and operational requirements, the Project will be designed to maximize net generation to the grid. ***Appendix G provides an assessment of balance of plant efficiency measures.***

The lowest GHG BACT emission limit (gas firing) in Table D-6 is 1,232 lb CO_{2e}/MW-hr (gross) for the NRG Cedar Bayou Project. For ULSD firing, the lowest rate in Table D-6 for oil alone is 1,741 lb/MWhr for the Exelon Perryman Project.

Another simple-cycle peaking project has recently been proposed in Massachusetts, which is the Exelon West Medway Project. This project is based on two GE LMS-100 turbines. For full-load ISO conditions with gas and ULSD firing, the proposed GHG BACT for the West Medway LMS-100 units is 1,151 Btu/kWhr (gas) and 1,551 Btu/kWhr (ULSD), both on a gross energy basis. These limits are stated to include a 9.5% margin plus degradation allowance.

A review of emission limits in SIPs did not identify any GHG emission limits for combustion turbines that are more stringent than limits achieved in practice by recently permitted and operated simple-cycle CTGs subject to BACT requirements. The MassDEP BACT guidelines do not provide GHG limits for a simple-cycle CTG.

5.2.7.5 Step 5: Selection of BACT

Each of the three technically feasible options in Step 3 can be used in tandem and, therefore, the top-level of control would be the application of all three technologies. However, CCS is eliminated as a BACT option due to its economic, energy and environmental impacts as demonstrated in the following discussion. Canal 3 is proposing to implement the remaining two control technologies for GHG emission reduction, high-efficiency generating technology and low-carbon fuels. The Project will utilize an H-class CTG that provides the highest efficiency of any available comparably sized CTG. Based upon the Project design, and adding a performance plus degradation margin of 7.1% for the life of the Project, the CTG will meet a heat rate of 9,897 Btu/kW-hr (gross) at full-load ISO conditions for natural gas firing, and 10,271 Btu/kW-hr (gross) at full-load ISO conditions for ULSD firing. This is equivalent to a GHG BACT emission rate of 1,178 lb CO_{2e}/MW-hr (gross) at full-load ISO conditions for natural gas firing, which compares favorably with the permitted GHG BACT limits in Appendix D, Table D-6. For ULSD firing, taking into account performance degradation, the proposed GHG BACT emission rate is 1,673 lb CO_{2e}/MW-hr (gross) at full-load ISO conditions. This value generally compares favorably with the oil-fired project values in Table D-6.

The proposed GHG BACT for the LMS-100 units at West Medway are approximately 2% lower than the proposed Project limits on gas and 7% lower than the proposed Project limits on ULSD. However, the LMS-100 does not offer the economy of scale that an H-class turbine provides as the initial capital cost of using LMS-100 technology will be at least 30% greater than using an H-class simple-cycle unit. There are other disadvantages of an LMS-100 project at this site as well. The LMS-100 is also not a very space-efficient machine. Three LMS-100 units (300 MW), including a collector bus switchyard, would occupy some 9 acres. The single 7HA.02 (no switchyard needed) only occupies about 6 acres. The LMS-100 also requires additional silencing to produce comparable noise levels and also needs water injection for NO_x control for both natural gas and ULSD firing. All these factors make the H-class simple cycle unit a better selection for the Project at this location to meet the peak power needs of southeastern Massachusetts.

CCS Economics Impacts

The capital expenditure required to capture CO_2 from the exhaust and compress it to the pressure required for transport and sequestration is prohibitive. The Report of the *Interagency Task Force on Carbon Capture and Storage* (ITF, 2010) indicates that it costs approximately $105 per ton of CO_2 captured to install and operate a post-combustion system on a new installation to capture and compress CO_2 for transport and sequestration. Applying this factor to the 932,325 tpy of CO_2 potentially emitted from the Project's simple-cycle gas turbine results in an estimated annual cost of over $97,000,000 per year; which is clearly prohibitive.

If the Project were to use the northern Michigan sequestration site at some point in the future should it become operable, captured CO_2 would have to be transported by pipeline. Pipelines are the most common method for transporting large quantities of CO_2 over long distances. There are currently approximately 3,600 miles of existing pipeline located in the United States, but none of these pipelines currently go from Massachusetts towards Michigan. As such, a CO_2 transportation pipeline would need to be constructed from the Project location to the northern Michigan location. The cost for permitting and constructing this pressurized pipeline would be economically prohibitive and impractical.

CCS Energy Impacts

CCS systems impose a very large parasitic load, which reduces the overall efficiency of the Project. The *Interagency Task Force on Carbon Capture and Storage* (ITF, 2010) estimates that the overall generating efficiency would be reduced by as much as a third. This would reduce the overall output of the plant by more than 100 MW. This reduction in efficiency would yield a cost to generate that would make it uneconomical to operate in the competitive ISO-NE market.

CCS Environmental Impacts

The reduction in overall plant output would not result in a ton per year reduction in any other pollutants that are subject to BACT. As a result, the emissions of every non-GHG BACT subject pollutant would increase by 50% on a lb/MWh basis. This increase in criteria pollutant emissions is clearly counterproductive for LAER and BACT for criteria pollutants.

As demonstrated above, even if it were commercially available, the economic, energy and environmental impacts to install and operate a CCS system would be unacceptable and, therefore, CCS was eliminated as a BACT option for the Project.

5.2.8 NH_3

5.2.8.1 Step 1: Identification of Control Technology Options

NH_3 emissions are a byproduct of its use as the reagent in the SCR system used to control NO_x emissions from the CTG. NH_3 is injected into the exhaust at a level slightly above stoichiometric requirements to ensure that the NO_x LAER emission rate can be met. NH_3 emissions are limited by controlling the injection rate to ensure compliance with the NO_x LAER emission rate but limiting the amount of unreacted NH_3 (i.e., "slip") that is exhausted to the atmosphere. The sole technology available is SCR design and ammonia injection control to limit slip.

5.2.8.2 Step 2: Identification of Technically Infeasible Control Technology Options

The technology identified in Step 1 is technically feasible.

5.2.8.3 Step 3: Ranking of Technically Feasible Control Technology Options

SCR design and NH_3 injection control to limit slip is technically feasible and the only control option.

5.2.8.4 Step 4: Evaluation of Most Effective Controls

The results of the review of simple-cycle turbine NH_3 emission limits is provided in Appendix D, Table D-7. The RBLC does contain one simple-cycle turbine with an NH_3 emission limit, the Black Hill Power Cheyenne Prairie Generating Station is permitted at 10 ppmvdc NH_3. One other known project (Braintree Electric's Watson Station) is also listed in Table D-7 with an NH_3 limit of 5.0 ppmvdc for both natural gas and oil firing. The MassDEP BACT Guidelines provide an NH_3 limit of 5.0 ppmvdc for both natural gas and oil firing for a simple-cycle CTG, with an optimization program for natural gas firing to achieve a limit down to 2.0 ppmvdc.

5.2.8.5 Step 5: Selection of BACT

The Project is proposing an NH_3 BACT limit of 5.0 ppmvdc for both natural gas and ULSD firing, equivalent to those for Watson Station. Canal 3 will also conduct an optimization program with a goal of achieving an NH_3 limit of 2.0 ppmvdc during natural gas firing consistent with the MassDEP BACT Guidelines. These proposed limits and optimization program represent the most stringent control identified for NH_3.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to MassDEP guidance, an evaluation of economic, energy and environmental impacts is not warranted.

5.2.9 Formaldehyde

5.2.9.1 Step 1: Identification of Control Technology Options

Formaldehyde is a VOC and CTGs have inherently low VOC emission rates. Emissions of VOC from a CTG occur as a result of incomplete combustion of organic compounds within the fuel. Formaldehyde results from the partial oxidation of CH_4. In an ideal combustion process, all carbon and hydrogen contained within the fuel are oxidized to form CO_2 and H_2O. Formaldehyde emissions can be minimized by the use of good combustion controls and add-on controls as described below.

The available formaldehyde control technologies identified for new large (>100 MW) simple-cycle turbines are as follows:

- *Oxidation Catalyst*: An oxidation catalyst system provides the most stringent level of control available for formaldehyde emissions from a CTG unit.
- *Combustion Controls*: Turbine vendors have designed lean pre-mix combustors for natural gas firing to provide a high degree of fuel oxidation. Combustion controls are commonly used in combination with an oxidation catalyst to minimize VOC emissions. However, combustion controls alone are less effective than an oxidation catalyst in combination with combustion controls.

5.2.9.2 Step 2: Identification of Technically Infeasible Control Technology Options

The technologies identified in Step 1 are both technically feasible.

5.2.9.3 Step 3: Ranking of Technically Feasible Control Technology Options

The two technologies in Step 1 can be operated in tandem and, therefore, application of both control measures is the top level of control.

5.2.9.4 Step 4: Evaluation of Most Effective Controls

The results of the review of simple-cycle turbine formaldehyde emission limits is provided in Appendix D, Table D-8. The RBLC lists three formaldehyde BACT determinations. Two of these are based on 0.0006 lb/MMBtu, while one is based on 0.0007 lb/MMBtu. While the Project is not subject to the formaldehyde emission standard under 40 CFR 60 Subpart YYYY for Stationary Combustion Turbines, Canal 3 is proposing the Subpart YYYY formaldehyde emissions limit that applies to units which fire oil more than 1000 hours per year of 0.091 ppmvdc as BACT (0.00022 lb/MMBtu on gas and 0.00023 lb/MMBtu on oil). The 0.091 ppmvdc limit was established as the Maximum Achievable Control Technology (MACT) limit after an exhaustive review by USEPA of achievable controls for formaldehyde emissions from new CTGs. NESHAP Subpart YYYY also establishes a limit of 0.091 ppmvdc for a new unit for gas firing in a lean pre-mix CTG, but this limit has been stayed indefinitely. Although the natural gas-fired limit under NESHAP Subpart YYYY is not applicable to the Project, this limit was also established by an exhaustive review by USEPA of achievable controls for formaldehyde emissions from CTGs. These limits are based upon a new CTG installing an oxidation catalyst to control formaldehyde emissions.

5.2.9.5 Step 5: Selection of BACT

Canal 3 believes that the process to establish the MACT emission limit under NESHAP Subpart YYYY is consistent with BACT and, therefore, proposes to meet 0.091 ppmvdc during both gas and ULSD firing as BACT for formaldehyde emissions. This limit will be met through the application of good combustion controls and an oxidation catalyst.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice. Pursuant to MassDEP guidance, an evaluation of economic, energy and environmental impacts is not warranted.

5.2.10 Summary of Proposed CTG Steady State BACT Emission Rate Limits

Table 5-1 summarizes the proposed LAER and BACT emission limits and associated control technology for the proposed CTG.

Table 5-1: Proposed PSD BACT Emission Limits for the Combustion Turbine

Pollutant	Fuel	Emission Rate (lb/MMBtu)	Emission Rate (ppmvdc)	Control Technology
NO_x	Natural Gas	0.0092	2.5	DLN and SCR
	ULSD	0.0194	5.0	Water Injection and SCR
VOC	Natural Gas	0.0026	2.0	Good combustion controls and an oxidation catalyst
	ULSD	0.0027	2.0	
CO	Natural Gas	***0.0079***	***3.5***	Good combustion controls and an oxidation catalyst
	ULSD	0.0118	5.0	
$PM/PM_{10}/PM_{2.5}$ ***>=75% Load***	Natural Gas	***0.0073***	18.1 lb/hr	Good combustion controls and low sulfur fuels
	ULSD	***0.026***	***65.8*** lb/hr	

Pollutant	Fuel	Emission Rate (lb/MMBtu)	Emission Rate (ppmvdc)	Control Technology
PM/PM$_{10}$/ PM$_{2.5}$ < 75% Load and >=MECL	***Natural Gas***	***0.012***	***18.1 lb/hr***	***Good combustion controls and low sulfur fuels***
	ULSD	***0.046***	***65.8 lb/hr***	
SO_2	Natural Gas	0.0015	n/a	Low sulfur fuels
	ULSD	0.0015	n/a	
H_2SO_4	Natural Gas	0.0016	n/a	Low sulfur fuels
	ULSD	0.0018	n/a	
NH_3	Natural Gas	0.0068 (initial) 0.0027 (goal)	5.0 (initial) 2.0 (goal)	SCR design
	ULSD	0.0072	5.0	
Formaldehyde	Natural Gas	0.00022	0.091	Good combustion controls and an oxidation catalyst
	ULSD	0.00023	0.091	
GHG[1]	Natural Gas	1,178 lb/MW-hr	n/a	High efficiency generation and low emitting fuels
	ULSD	1,673 lb/MW-hr	n/a	

[1] At full load ISO conditions, gross energy basis.

5.2.11 Startup and Shutdown Operations

During SUSD operation, pollutant emissions may be above steady-state emissions rates, especially emissions of NO_x, CO and VOC. During SUSD, combustion conditions are less than ideal resulting in higher emissions of pollutants based upon proper combustor design and operation. In addition, the control technologies employed to meet the BACT emission limits, in particular the oxidation catalyst and SCR, require minimum operating temperatures that may not be met during initial startup or when the CTG is below its minimum rated operating load.

There are no control technologies to limit SUSD emissions beyond those already established as the BACT control technologies for steady-state operation. The oxidation catalyst is a passive reactor and will control emissions of CO whenever it is operating above its minimum operating temperature. When the SCR catalyst is below its minimum operating temperature, NH_3 is not injected as it would not react with NO_x and be emitted as slip. To minimize NO_x emissions during startup, Canal 3 will initiate NH_3 injection as soon as the SCR catalyst reaches its minimum operating temperature and other SCR design criteria are met.

To establish BACT emission rate limits for SUSD operation, emissions data from the vendor are relied upon as the vendor has performance data from test cell operation for the selected make and model CTG. Emissions of $PM/PM_{10}/PM_{2.5}$ during SUSD are expected to be equal to or less than their steady-state emission rates on a lb/hr basis. Provided in Table 5-2 are the vendor-specified emissions of NO_x, VOC, and CO during SUSD operation. The emissions are presented in terms of pounds emitted per startup and shutdown event. A startup event is defined as the time from initial combustion through achieving the BACT emission rate limit. A shutdown event is defined as the time from initiating turndown of the CTG until fuel flow is shutoff. Short-term startup and shutdown emission limits will be evaluated after a year of actual operation and revised values may be proposed if needed.

Table 5-2: Proposed Provisional Startup and Shutdown Emission Limits for the Combustion Turbine

	Fuel	NO_x (lb/event)	CO (lb/event)	VOC (lb/event)	$PM/PM_{10}/PM_{2.5}$ (lb/event)
Startup	Natural Gas	151	130	9	9.1
	ULSD	219	163	12	48.2
Shutdown	Natural Gas	7	133	25	4.2
	ULSD	8	25	3	12.8

5.3 EMERGENCY GENERATOR ENGINE

5.3.1 Fuels

5.3.1.1 Step 1: Identification of Control Technology Options

The raw material for the emergency generator engine is the fuel. It is critical for the emergency generator engine to have its own stand-alone fuel source in the event that the emergency includes disruption of fuel from an outside source, such as natural gas. The primary purpose of the emergency generator is to be able to shut the plant down safely in the event of an electric power outage. Generator engines are available that can fire natural gas or diesel; to incorporate a stand-alone fuel source, the available fuel options are LNG and ULSD.

5.3.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Use of interruptible natural gas is not feasible for an emergency engine that must be able to operate during an emergency. LNG storage was eliminated as technically infeasible per the analysis in Section 4.2.1.2.

5.3.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

The sole stand-alone fuel source available for the emergency generator engine is ULSD.

5.3.1.4 Step 4: Evaluation of Most Effective Controls

Under 310 CMR 7.05, all distillate oil sold in Massachusetts as of July 1, 2018 must be ULSD, having a maximum sulfur content of 0.0015% sulfur by weight (15 ppmw). Also, existing emergency diesel generators installed in Massachusetts after March 1, 2006, are required to use ULSD under the provisions of 310 CMR 7.26(42). Therefore, use of ULSD in emergency generators in Massachusetts is common practice.

5.3.1.5 Step 5: Select BACT

The emergency generator engine will be fired with ULSD having a sulfur content no greater than 15 ppmw.

5.3.2 NO_x

5.3.2.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-emission engine design is the only known process modification that can be made to reduce NO_x emissions from a diesel engine.

Add-on Controls

SCR is a technically feasible option to control NO_x emissions from non-emergency diesel engines.

5.3.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Tier 4 engine design is technically feasible. SCR is considered technically infeasible for an emergency diesel generator since it has not been demonstrated in practice to our knowledge. However, since SCR is technically feasible for non-emergency diesel engines, SCR has been carried into Step 3 to show it is not cost effective as well for this application.

5.3.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

SCR can normally achieve 90% removal of NO_x emissions. However, for an emergency generator that will be used for short periods of testing and facility shutdown in an actual emergency, the ability of the SCR to control emissions in practice may be significantly reduced since the engine/SCR takes time to warm up to achieve appreciable NO_x control.

5.3.2.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency engine to meet the applicable emission standards under 40 CFR 89. The MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in state SIPs did not identify any NO_x emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89.

A review of recent NO_x emission limits for emergency generator diesel engines installed as part of a major source simple-cycle generating projects, as summarized in Table D-9 in Appendix D, show that most of these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 as required by 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on controls for emergency generator diesel engines.

Emergency engines are now commercially available that meet the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039.104(g), Table 1, which is 3.5 grams/kW-hr of NO_x.

5.3.2.5 Step 5: Selection of BACT

The top level of control actually demonstrated in practice is considered to be compliance with the applicable limits under 40 CFR 1039.104(g), Table 1 for the Tier 4 Alternate FEL Cap limits and firing of ULSD that meets the requirements of 40 CFR 80, Subpart I. The applicable limit for a 581-kW (mechanical) new emergency stationary CI engine under 40 CFR 1039.104, Table 1, which is 3.5 grams/kW-hr of NO_x.

Economic Impacts

Since SCR is technically feasible for non-emergency generators, an economic analysis of its cost effectiveness was conducted and is presented in Appendix B. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions, although this degree of control is unlikely due to the intermittent operation of the emergency engine, primarily for periodic readiness testing. The calculations indicate that the cost effectiveness of an SCR is over $60,000 per ton of NO_x controlled at maximum allowable operation of 300 hours per year; this cost is considered excessive. So in addition to being technically infeasible for this emergency application, SCR is also not cost effective.

There are no energy or environmental issues with a Tier 4 generator that would indicate selection of SCR as BACT, given the unfavorable economics.

The proposed controls represent BACT and is the most stringent level of control actually demonstrated in practice.

5.3.3 CO and VOC

5.3.3.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-emission engine design is the only known process modification that can be made to reduce CO and VOC emissions from a diesel engine.

Add-on Controls

An oxidation catalyst is a technically feasible option to control CO emissions from diesel engines. Some amount of VOC reduction would be expected to be achieved with application of an oxidation catalyst on an emergency diesel engine. However, the amount of reduction depends on the specific organic species present, which is not known.

5.3.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Both Tier 4 engine design and an oxidation catalyst are technically feasible, although application of an oxidation catalyst is unusual for an emergency engine.

5.3.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

Low-CO engine design (Tier 4) and an oxidation catalyst are technically feasible.

5.3.3.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency engine to meet the applicable emission standards under 40 CFR 89. The MassDEP regulations under 310 CMR 7.26(42) also requires new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in state SIPs did not identify any CO or VOC emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89.

A review of recent CO and VOC emission limits for emergency generator diesel engines installed as part of a major source simple-cycle generating projects, as summarized in Table D-9 in Appendix D, show that most of these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 as required by 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on controls for emergency generator diesel engines.

Tier 4 emergency engines are now commercially available and the Project is proposing to install an engine that meets the Tier 4 engine limits for generator engines under 40 CFR 1039.101, Table 1, which is 3.5 grams/kW-hr of CO and 0.19 grams/kW-hr of VOC.

5.3.3.5 Step 5: Selection of BACT

Canal 3 proposes that CO and VOC BACT be an engine that meets the Tier 4 limits of 3.5 grams/kW-hr (CO) and 0.19 grams/kW-hr (VOC) under 40 CFR 1039.101, Table 1.

Economic Impacts

Since an oxidation catalyst is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix B. The oxidation catalyst has been conservatively assumed to control 90% of the potential CO emissions even though somewhat less control is likely in this application. The calculations indicate that the cost effectiveness of an oxidation catalyst is over $7,000 per ton of CO. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely) and 90% CO control of the full potential to emit is achieved.

For BACT evaluation purposes, we believe this oxidation catalyst analysis for CO is adequate to demonstrate an oxidation catalyst is also not cost effective for VOC, since potential VOC emissions without a catalyst are only 5.4% of CO emissions on a mass basis.

There are no energy or environmental issues with a Tier 4 generator that would indicate selection of an oxidation catalyst as BACT, given the unfavorable economics.

The proposed controls represent BACT and is the most stringent level of control actually demonstrated in practice.

5.3.4 PM/PM_{10}/$PM_{2.5}$

5.3.4.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-PM engine design is the only known process modification that can be made to reduce PM emissions from a diesel engine.

Add-on Controls

A diesel particulate matter filter (DPF) is a technically feasible option to control PM emissions from an emergency generator.

5.3.4.2 Step 2: Identification of Technically Infeasible Control Technology Options

Low-PM engine design and a DPF are both technically feasible, although application of a DPF is unusual for an emergency generator diesel engine.

5.3.4.3 Step 3: Ranking of Technically Feasible Control Technology Options

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 4 Alternate FEL Cap engine design, which is based on low-emission engine design.

5.3.4.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency engine to meet the applicable emission standards under 40 CFR 89. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. A review of emission limits in SIPs did not identify any PM emission limits for new emergency engines that are more stringent than the limits provided in 40 CFR 89.

A review of recent PM emission limits for emergency generator diesel engines installed as part of a major source simple-cycle generating project, as summarized in Table D-9 in Appendix D, show that most of these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 as required by 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency generator diesel engines.

The Moxie Patriot Project has a PM limit of 0.02 grams/hp-hr, which corresponds to 0.027 grams/kW-hr. It is suspected that this is an RBLC entry error as the limit is inconsistent with known PM emissions from diesel engines.

5.3.4.5 Step 5: Selection of BACT

The top level of control would be the installation of a low-PM (Tier 4) engine with a DPF. However, a DPF was eliminated due to economic impacts as described below. The top level of control demonstrated in practice is determined to be compliance with the Tier 4 Alternate FEL Cap limit for generator engines under 40 CFR 1039, Table 3, which is 0.1 grams/kW-hr of PM. Canal 3 is proposing to install an engine that meets this limit.

Economic Impacts

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix B. This analysis indicates that the cost effectiveness for an active DPF is nearly $1,000,000 per ton of $PM/PM_{10}/PM_{2.5}$ controlled. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely).

There are no energy or environmental issues with a Tier 4 generator engine that would indicate selection of a DPF as BACT, given the unfavorable economics.

The proposed controls represent BACT and is the most stringent level of control actually demonstrated in practice.

5.3.5 SO_2 and H_2SO_4

The only control technology for reducing SO_2 and H_2SO_4 emissions from the emergency generator engine is to utilize low-sulfur fuels. No other control technologies are available for the control of H_2SO_4 from an emergency engine and, therefore, the five-step BACT process was truncated. The Project will utilize ULSD with a maximum sulfur content of 15 ppmw, which is the lowest sulfur fuel available and represents the top level of control for SO_2 and H_2SO_4 from an emergency engine. The proposed SO_2 BACT limit is 0.0015 lb/MMBtu based on 100% conversion of fuel sulfur to SO_2. The proposed H_2SO_4 BACT limit is based on 5% conversion of fuel sulfur to SO_3/H_2SO_4, with the molecular weight correction from the SO_2 limit of 0.0015 lb/MMBtu. This results in H_2SO_4 emissions of 0.00012 lb/MMBtu.

5.3.6 Greenhouse Gases (GHGs)

The GHG BACT discussion in Section 4.2.7 describes the difficulties in controlling GHG emissions from the primary source of emissions from the Project, which is the CTG. The emergency generator engine is an insignificant source of GHG emissions at 123 tpy, which represents approximately 0.01% of the Project's GHG emissions. There are no technically feasible means of reducing GHG emissions from the emergency generator engine other than restricting operating hours. The emergency generator engine will operate no more than 300 hours per year. This restriction will limit annual GHG emissions to 123 tpy, which is consistent with the limits for other emergency generator engines listed in Table D-9 in Appendix D. ***The proposed BACT limits for GHG as CO_2e for the emergency generator are 819 lb/hr and 162.85 lb/MMBtu.***

5.4 EMERGENCY FIRE PUMP ENGINE

5.4.1 Fuels

5.4.1.1 Step 1: Identification of Control Technology Options

The raw material for the emergency fire pump engine is the fuel. It is critical for the emergency fire pump engine to have its own stand-alone fuel source in the event that the emergency includes disruption of fuel from an outside source, such as natural gas. The purpose of the emergency fire pump is to provide firefighting capability during a fire onsite. Fire pump engines are available that can fire natural gas or diesel; to incorporate a stand-alone fuel source, the available fuel options are LNG and ULSD.

It is important to note here as well that two fire pumps will be provided for the Project to ensure 100% backup of the fire protection system water supply. One fire pump will be driven by an electric motor and the other will be driven by a diesel engine. Each pump will be capable of delivering total system requirements at design pressure and flow rate with any one pump out of service. Therefore, the diesel fire pump is essentially a backup unit that would typically be used in a fire fighting emergency if there is also a simultaneous loss of electric power.

5.4.1.2 Step 2: Identification of Technically Infeasible Control Technology Options

Use of interruptible natural gas is not feasible for an emergency fire pump engine that must be able to operate during an emergency. LNG storage was eliminated as technically infeasible at the Facility per the analysis in Section 5.2.1.

5.4.1.3 Step 3: Ranking of Technically Feasible Control Technology Options

The sole stand-alone fuel source available for the emergency diesel fire pump is ULSD.

5.4.1.4 Step 4: Evaluation of Most Effective Controls

Under 310 CMR 7.05, all distillate oil sold in Massachusetts as of July 1, 2018 must be ULSD having a maximum sulfur content of 0.0015% sulfur by weight (15 ppmw). Also, existing emergency diesel engines installed in Massachusetts after March 1, 2006, are required to use ULSD under the provisions of 310 CMR 7.26(42). Therefore, use of ULSD in emergency engines in Massachusetts is common practice.

5.4.1.5 Step 5: Selection of BACT

The emergency diesel fire pump engine shall be fired with ULSD having a sulfur content no greater than 15 ppmw.

5.4.2 NO_x

5.4.2.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-NO_x engine design is the only known process modification that can be made to reduce NO_x emissions from a diesel engine. Low-NO_x engine design for a 135-bhp emergency diesel fire pump engine is a Tier 3 engine rated at 4.0 grams/kW-hr NO_x and NMHC combined. Tier 4 emergency diesel fire pumps are not available.

Add-on Controls

SCR is a technically feasible option to control NO_x emissions from non-emergency diesel engines.

5.4.2.2 Step 2: Identification of Technically Infeasible Control Technology Options

Tier 3 engine design is technically feasible. SCR is considered technically infeasible for an emergency diesel fire pump since it has not been demonstrated in practice to our knowledge. However, since SCR is technically feasible for non-emergency diesel engines, SCR has been carried into Step 3 to show it is not cost effective as well for this application.

5.4.2.3 Step 3: Ranking of Technically Feasible Control Technology Options

SCR can normally achieve 90% removal of NO_x emissions, so it is more effective than the Tier 3 engine design, which is based on low-NO_x engine design. However, for an emergency diesel fire pump that will be used for short periods of testing and limited use in actual emergencies, the ability of the SCR to control emissions will be significantly reduced since the engine/SCR takes time to warm up to achieve appreciable NO_x control.

5.4.2.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency fire pump engine to meet the applicable emission standards under NSPS Subpart IIII, Table 4. The MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. The applicable limits under NSPS Subpart IIII, Table 4 are equal to or more stringent than 40 CFR 89. A review of emission limits in SIPs did not identify any NO_x emission limits for new emergency engines that are more stringent than the limits provided in NSPS Subpart IIII, Table 4.

A review of recent NO_x emission limits for emergency fire pump diesel engines installed as part of major source simple-cycle generating projects, as summarized in Table D-10 in Appendix D, show that these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency fire pump diesel engines.

5.4.2.5 Step 5: Selection of BACT

The top level of control actually demonstrated in practice is determined to be compliance with the applicable limits under 40 CFR Part 60, Subpart IIII and firing of ULSD that meets the requirements of 40 CFR 80, Subpart I. The applicable limit for a 135-bhp emergency fire pump engine is USEPA's Tier 3 limit under NSPS Subpart IIII, Table 4, which is 4.0 grams per kW/hp-hr of NO_x and NMHC combined.

Economic Impacts

Since SCR is technically feasible for non-emergency engines, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix B. This analysis indicates that the cost effectiveness of SCR is over $100,000 per ton of NO_x. This cost is excessive, even if the emergency diesel fire pump runs the maximum allowable amount of 300 hours per year (unlikely). So in addition to being technically infeasible for this emergency application, SCR is also not cost effective. There are no energy or environmental issues with a Tier 3 generator that would indicate selection of a SCR is BACT, given the unfavorable economics.

The proposed controls represent the top level of control and have been demonstrated to be achievable in practice.

5.4.3 CO and VOC

5.4.3.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-emissions engine design is the only known process modification that can be made to reduce CO emissions from a diesel engine. Low-emission engine design for a 135-bhp emergency diesel fire pump engine is a Tier 3 engine rated at 5.0 grams/kW-hr CO. VOC is limited by Tier 3 and the 40 CFR 60 Subpart IIII combined limit of 4.0 grams (NO_x + NMHC) of 4.0 grams/kW-hr. The VOC component is conservatively assumed to be the Tier 1 limit of 1.3 grams/kW-hr.

Add-on Controls

An oxidation catalyst is a technically feasible option to control CO and VOC emissions from diesel engines.

5.4.3.2 Step 2: Identification of Technically Infeasible Control Technology Options

Both Tier 3 engine design and an oxidation catalyst are technically feasible, although application of an oxidation catalyst is unusual for an emergency fire pump engine.

5.4.3.3 Step 3: Ranking of Technically Feasible Control Technology Options

An oxidation catalyst can normally achieve 90% remove of CO emissions, so it is more effective than the Tier 3 engine design which is based on low-emission engine design. However, for an emergency diesel fire pump engine, if this unit is used just for short periods of test and facility shutdown in an actual emergency, the ability of the oxidation catalyst to control CO emissions will be reduced since the engine catalyst takes time to warm up to achieve effective control. Some amount of VOC reduction would be expected to be achieved with application of an oxidation catalyst on an emergency diesel fire pump engine. However, the amount of reduction depends on the specific organic species present, which is not known.

5.4.3.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require new emergency fire pump engines to meet the applicable emission standards under

NSPS Subpart IIII, Table 4. The MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. The applicable limits under NSPS Subpart IIII, Table 4 are equal to or more stringent than 40 CFR 89. A review of emission limits in SIPs did not identify any CO or VOC emission limits for new emergency fire pump engines that are more stringent than the limits provided in NSPS Subpart IIII, Table 4.

A review of recent CO and VOC emission limits for emergency fire pump diesel engines installed as part of major source simple-cycle generating projects, as summarized in Table D-10 in Appendix D, show that these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency fire pump diesel engines.

5.4.3.5 Step 5: Selection of BACT

The top level of control actually demonstrated in practice for an emergency diesel fire pump engine is determined to be compliance with the applicable limits under 40 CFR Part 60, Subpart IIII and firing of ULSD that meets the requirements of 40 CFR 80, Subpart I. The applicable limit for a 135-bhp new emergency fire pump engine is USEPA's Tier 3 limit under NSPS Subpart IIII, Table 4, which is 5.0 grams/kW-hr of CO. VOC is limited by Tier 3 and the 40 CFR 60 Subpart IIII combined limit of 4.0 grams/kW-hr (NOx + NMHC). The VOC component is conservatively assumed to be the Tier 1 limit of 1.3 grams/kW-hr.

Economic Impacts

Since an oxidation catalyst is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix B. This analysis indicates that the cost effectiveness of an oxidation catalyst is over $12,000 per ton of CO. This cost is excessive, even if the emergency diesel fire pump runs the maximum allowable amount of 300 hours per year (unlikely).

For BACT evaluation purposes, we believe this oxidation catalyst analysis for CO is adequate to demonstrate an oxidation catalyst is also not cost effective for VOC, since potential VOC emissions without a catalyst are only 26% of CO emissions on a mass basis.

There are no energy or environmental issues with a Tier 3 emergency diesel fire pump engine that would indicate selection of an oxidation catalyst is BACT, given the unfavorable economics.

The proposed controls represent the top level of control that have been demonstrated to be achievable in practice.

5.4.4 PM/PM_{10}/$PM_{2.5}$

5.4.4.1 Step 1: Identification of Control Technology Options

Process Modifications

Low-PM engine design is the only known process modification that can be made to reduce PM emissions from a diesel engine. Low-emission engine design for a 135-bhp emergency diesel fire pump engine is a Tier 3 engine rated at 0.30 grams/kW-hr PM.

Add-on Controls

DPF is a technically feasible option to control PM emissions from diesel engines.

5.4.4.2 Step 2: Identification of Technically Infeasible Control Technology Options

Low-PM engine design and DPF are both technically feasible, although application of a DPF is unusual for an emergency diesel engine.

5.4.4.3 Step 3: Ranking of Technically Feasible Control Technology Options

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 3 engine design, which is based on low-emission engine design.

5.4.4.4 Step 4: Evaluation of Most Effective Controls

Stationary internal combustion engines are subject to 40 CFR Part 60, Subpart IIII and 40 CFR 63, Subpart ZZZZ. These regulations require a new emergency fire pump engine to meet the applicable emission standards under NSPS Subpart IIII, Table 4. MassDEP regulations under 310 CMR 7.26(42) also require new emergency engines to meet the applicable emission limitations for non-road engines under 40 CFR Part 89 at the time of installation. The applicable limits under NSPS Subpart IIII, Table 4 are equal to or more stringent than 40 CFR 89. A review of emission limits in SIPs did not identify any PM emission limits for new emergency engines that are more stringent than the limits provided in NSPS Subpart IIII, Table 4.

A review of recent PM emission limits for emergency fire pump diesel engines installed as part of major source simple-cycle generating projects, as summarized in Table D-10 in Appendix D, show that these engines were required to meet the applicable emission limitations for non-road engines under 40 CFR 60, Subpart IIII. No limits were found that required installation of add-on pollution controls for emergency fire pump diesel engines.

5.4.4.5 Step 5: Selection of BACT

The top level of control would be the installation of both a low-PM engine with DPF. However, DPF was eliminated due to economic impacts as described below. The next level of control was determined to be compliance with the applicable limits under 40 CFR Part 60, Subpart IIII and firing of ULSD that meets the requirements of 40 CFR 80, Subpart I. The applicable limit for a 135-bhp new emergency fire pump engine is USEPA's Tier 3 limit under NSPS Subpart IIII, Table 4, which is 0.30 grams per/kW-hr.

Economic Impacts

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Appendix B. This analysis indicates that the cost effectiveness of an active DPF is nearly $700,000 per ton of $PM/PM_{10}/PM_{2.5}$. This cost is excessive, even if the emergency diesel fire pump engine were to run the maximum allowable amount of 300 hours per year (unlikely).

There are no collateral energy or environmental issues with a Tier 3 generator that would indicate selection of a DPF is BACT, given the unfavorable economics.

The proposed controls represent the top level of control that have been demonstrated to be achievable in practice.

5.4.5 SO_2 and H_2SO_4

The only control technology for reducing SO_2 and H_2SO_4 emissions from the emergency fire pump engine is to utilize low sulfur fuels. No other control technologies are available for the control of H_2SO_4 from an emergency fire pump engine; therefore, the five-step BACT process was truncated. The Project will utilize ULSD with a maximum sulfur content of 15 ppmw, which is the lowest sulfur fuel available and represents the top level of control for SO_2 and H_2SO_4 from an emergency fire pump engine. The proposed SO_2 BACT limit is 0.0015 lb/MMBtu based on 100% conversion of fuel sulfur to SO_2. The proposed H_2SO_4 BACT limit is based on 5% conversion of fuel sulfur to SO_3/H_2SO_4, with the molecular weight correction from the SO_2 limit of 0.0015 lb/MMBtu. This results in H_2SO_4 emissions of 0.00012 lb/MMBtu.

5.4.6 GHGs

The GHG BACT discussion in Section 4.2.7 describes the difficulties in controlling GHG emissions from the primary source of emissions from the Project, which is the CTG. The emergency fire pump engine is an insignificant source of GHG emissions at 29 tpy, which represents approximately 0.003% of the Project's GHG emissions. There are no technically feasible means of reducing GHG emissions from the emergency fire pump engine other than restricting operating hours. The emergency fire pump engine will operate no more than 100 hours per year for readiness testing purposes in accordance with NSPS Subpart IIII, and will operate no more than 300 hours per year in total. These restrictions will limit annual GHG emissions to 29 tpy, which is consistent with the limits for other emergency fire pump engines listed in Table D-10 in Appendix D. ***The proposed BACT limits for GHG as CO_2e for the emergency diesel fire pump are 195 lb/hr and 162.85 lb/MMBtu***.

5.4.7 Ancillary Source BACT Summary

Table 5-3 summarizes the proposed PSD BACT emission limits and associated control technology for the Project's ancillary emission sources.

Table 5-3: Proposed BACT Emission Limits for the Emergency Engines

Pollutant	Emergency Generator	Emergency Fire Pump
NO_x + VOC	3.5 g/kW-hr NO_x[1] 0.19 g/kW-hr VOC[1]	4.0 grams/kW-hr[1]
CO	3.5 grams/kW-hr[1]	5.0 grams/kW-hr[1]
PM	0.10 grams/kW-hr[1]	0.30 grams/kW-hr[1]
SO_2	0.0015 lb/MMBtu	0.0015 lb/MMBtu
H_2SO_4	0.00012 lb/MMBtu	0.00012 lb/MMBtu
GHGs ***as CO_2e***	***819 lb/hr*** ***162.85 lb/MMBtu***	***195 lb/hr*** ***162.85 lb/MMBtu***

[1] Proposed emission limits in accordance with applicable 40 CFR 1039 or 40 CFR 60 Subpart IIII emission test cycle as demonstrated by manufacturer's certification.

6.0 AIR QUALITY IMPACT ANALYSIS

As described in Section 3.2.2, the Project is required to demonstrate compliance with NAAQS and MAAQS. As there is no NAAQS/MAAQS for H_2SO_4, it is evaluated as an air toxic. All applicable air toxics, including H_2SO_4, have been evaluated in accordance with MassDEP's air toxics policy. The Project is also required to demonstrate compliance with the PSD Increments. The PSD Increment analysis is discussed in the PSD Permit Application, which is provided under separate cover.

Air quality dispersion modeling uses mathematical formulations to simulate how a pollutant emitted by a source will disperse in the atmosphere to predict concentrations at downwind receptor locations. An evaluation of the potential impacts of the proposed Project's air emissions on ambient air quality has been conducted using USEPA's regulatory model, AERMOD (v15181). The air quality dispersion modeling analyses for the Project have been conducted as specified in the Air Quality Dispersion Modeling Protocol, submitted to and approved by MassDEP. These procedures are in accordance with 40 CFR Part 51 Appendix W, the USEPA's *Guideline on Air Quality Models* (USEPA, 2005), *Modeling Guidance for Significant Stationary Sources of Air Pollution* (MassDEP, 2011), the AERMOD Implementation Guide (USEPA, 2015), and supplemented by additional agency guidance.

The dispersion modeling for the Project evaluates worst-case operating conditions to predict the appropriate maximum ground-level concentration for each pollutant and averaging period. The appropriate maximum concentrations from the worst-case scenarios are compared to the corresponding SILs. If the maximum concentration is below the corresponding SIL, then compliance is demonstrated and no additional analysis is necessary. However, if any maximum predicted concentration is equal to or greater than its corresponding SIL, a cumulative impact analysis must be conducted with other major emission sources in the area, as identified by the MassDEP.

As discussed in the following sections, the modeling analysis demonstrates that the proposed Project will not cause or significantly contribute to an exceedance of any NAAQS, MAAQS, or MassDEP non-criteria pollutant threshold.

6.1 SOURCE PARAMETERS AND EMISSION RATES

The proposed Project will include one new combustion turbine and ancillary equipment (specifically, one new emergency generator and one new fire water pump). In addition to modeling the impacts from the Project, the modeling analysis includes consideration of cumulative impacts from the existing Station sources. Table 6-1 lists the physical stack characteristics for each source that was included in the modeling.

Table 6-1: Stack Characteristics for the Proposed Project and the Existing Canal Generating Station

Source	Status	UTM E[1] (m)	UTM N[1] (m)	Base Elevation (meters)	Stack Height (feet)	Stack Diameter (feet)
Canal 3 CT	Proposed	374,636.75	4,625,364.08	4.88	220	25
Emergency Gen.	Proposed	374,636.50	4,625,375.45	4.88	25	0.75
Fire Water Pump	Proposed	374,802.48	4,625,326.75	4.88	25	0.33
Canal Unit 1,2	Existing	374,565.91	4,625,318.96	3.66	498	25.5
Emergency Gen 1	Existing	374,393.38	4,625,435.85	3.66	14.4	0.66
Emergency Gen 2	Existing	374,608.72	4,625,460.22	3.66	14.4	0.66
Fire Water Pump	Existing	374,397.46	4,625,433.02	3.66	14.1	0.33
Gas Heater	Existing	373,685.91	4,625,564.01	3.66	15	1.6

[1]Universal Transverse Mercator Zone 19, based on North American Datum 83

Modeling for the Project was conducted in a manner that utilizes the worst-case operating conditions for the proposed new combustion turbine in combination with the ancillary sources impacts in an effort to predict the highest impact for each averaging period. The Project is requesting a permit that will allow up to 4,380 hours per year of operation for the new simple-cycle turbine. Turbine operation could range from up to 4,380 hours per year on natural gas alone to 3,660 hours per year on natural gas and 720 hours per year on ULSD. However, the modeling analyses presented herein conservatively assume the CTG will operate up to 1,440 hours per year on ULSD. ***Also, the modeling analyses presented herein conservatively assumes CTG CO emission rates for natural gas firing of 4.0 ppm instead of the 3.5 ppm now proposed as the gas-firing permit limit.*** The proposed GE 7HA.02 turbine is rated at a maximum capacity of 3,425 MMBtu/hr at 0°F while firing natural gas and 3,471 MMBtu/hr at 0°F while firing ULSD. The emissions will exit to the atmosphere through a 220-foot tall stack with an inside exit diameter of 25 feet. Since proposed new combustion turbine emission rates and flue gas characteristics for a given turbine load vary as a function of ambient temperature, data were derived for the following ambient temperatures and load scenarios:

- three operating loads (Base [100%], Mid [~75%], and Min [30-40%])
- five ambient temperatures (90°F, 59°F, 50°F, 20°F, and 0°F)

In order to calculate conservatively ground-level concentrations, a composite “worst-case” set of emission parameters was used in the modeling. For each turbine load, the highest pollutant-specific emission rate coupled with the lowest exhaust temperature and exhaust flow rate was selected. Tables 6-2 and 6-3 summarize the worst-case emission parameters over the three operating loads for natural gas and ULSD firing, respectively.

Table 6-2: Worst-Case Operational Data for the Proposed Simple-Cycle Combustion Turbine firing Natural Gas

Parameter		Load Value		
		Base	Mid	Min
Exit Temperature (°F)		750.0	750.0	750.0
Exit Velocity (feet/sec)		128.29	107.94	75.30
Pollutant Emissions (lb/hr)	SO_2	5.14	4.11	2.80
	PM_{10}	18.10	16.60[2]	15.60[2]
	$PM_{2.5}$	18.10	16.60[2]	15.60[2]
	NO_X	31.51	25.24	17.19
	CO[1]	30.82	24.69	16.82

[1] ***Conservatively based on 4.0 ppm CO, although Project will meet 3.5 ppm.***

[2] ***Manufacturer guarantees for part load conditions revised to 18.1 lb/hr. The min load case is controlling for gas portion of annual impacts but overall calculated impacts remain conservative because ULSD operation is now limited to 720 hours per year (at a lower emission rate) and annual PM_{10}/$PM_{2.5}$ impacts have been calculated based on 1440 hours per year of ULSD operation.***

Table 6-3: Worst-Case Operational Data for the Proposed Simple-Cycle Combustion Turbine firing ULSD

Parameter		Load Value		
		Base	Mid	Min
Exit Temperature (°F)		750.0	750.0	750.0
Exit Velocity (feet/sec)		122.74	104.18	74.59
Pollutant Emissions (lb/hr)	SO_2	5.21	4.17	2.66
	PM_{10}	86.7[1]	90.6[1]	96.3[1]
	$PM_{2.5}$	86.7[1]	90.6[1]	96.3[1]
	NO_X	67.35	53.96	34.34
	CO	40.96	32.82	20.89
	Pb	***1.1E-02***	***8.7E-03***	***5.5E-03***

[1] ***Project will now meet 65.8 lb/hr for all cases.***

The proposed combustion turbine will be operated as a peaking unit; therefore, in addition to estimating the steady-state operational impacts, the proposed new combustion turbine's SUSD conditions were also included in the AERMOD operating scenario modeling for the pollutants that have short-term standards (SO_2, PM_{10}, $PM_{2.5}$, NO_2, and CO). SUSD modeling was not conducted for annual averaging periods. The vendor data suggests that startup events will last only 10-30 minute and shutdown events will last only 8-14 minutes depending on the fuel. Therefore, modeling for SUSD is comprised of a representative hourly profile of emissions that accounts for a startup or shutdown within 1 hour. For longer averaging periods (i.e., 24-hour), a limited number of startups and shutdowns were considered in a day as it is unreasonable to expect that the turbine will startup and shutdown 24 hours per day. Since SUSD emissions occur under different exhaust parameters (which are different from exhaust parameters for steady-state operations), the hourly profile of emissions for an SUSD hour was modeled assuming co-located stacks.

For the 1-hour, 3-hour, and 8-hour averaging periods, two co-located stacks were used. (This is just a calculation technique and does not mean two or three stacks are being constructed, as discussed below; only a single physical stack for the new CTG is being constructed.) Stack 1 consists of the startup stack and is modeled with the total emissions from a single startup event. Stack 2 consists of the normal operation stack representing the balance of the hour that the turbine is not operating in startup mode. The emissions for Stack 2 are scaled based on the portion of the hour that the turbine is operating under normal conditions. With the exception of CO during shutdown from natural gas firing, startup emissions are always higher with lower plume rise, as shown in Table 6-4. Therefore, for CO, natural gas startup, the shutdown emission rate was conservatively used with the startup stack parameters.

For the 24-hour averaging period, three co-located stacks were used in the modeling. Stack 1 consists of the startup stack and is modeled with the total emissions from a single startup event. Stack 2 consists of the shutdown stack and is modeled with the total emissions from a single shutdown event. Stack 3 consists of the normal operation stack representing the balance of the hour that the turbine is not operating in startup or shutdown mode. The emissions for Stack 3 are scaled based on the portion of the hour that the turbine is operating under normal conditions (both minimum and maximum load conditions were evaluated). As noted above, since the turbine will not be starting up and shutting down every hour of the day, the modeling assumed a maximum of six startup and six shutdown events per day. The daily emissions were scaled accordingly to account for this assumption. For the remainder of the day, it was assumed that the turbine is at normal load operations.

For all averaging periods (except annual), the modeled concentrations from all three stacks are combined to determine the total hourly modeled concentration.

Table 6-4: Startup/Shutdown Data for the Proposed Simple-Cycle Combustion Turbine

Parameter		Natural Gas		ULSD	
		Startup	Shutdown	Startup	Shutdown
Exit Temperature (°F)		680	750	680	750
Exit Velocity (feet/sec)		35.73	44.24	35.73	44.24
Pollutant Emissions (lb/hr)	SO_2	0.25	0.05	0.24	0.04
	PM_{10}	2.28	1.05	12.05	3.2
	$PM_{2.5}$	2.28	1.05	12.05	3.2
	NO_X	151	7	219	8
	CO	130	133	163	25

The Project will also include a ULSD-fired emergency generator engine and a ULSD-fired emergency fire pump engine, which are each expected to operate approximately 1 hour/week per unit for maintenance and no more than 300 hours/year per unit including emergency operation. Therefore, the modeled short-term emissions (24-hour or less) were normalized to reflect 1 hour of operation within the averaging period for the assessment of short-term modeled averaging periods. The modeled annual emission rates for these emergency sources were normalized based on the 300 hours per year for the assessment of annual modeled averaging periods. Additionally, for the 1-hour NO_2 and SO_2 modeling, per USEPA guidance for modeling intermittent sources (USEPA, 2011), these emission rates are annualized (i.e., based on 300 hours per year). Source parameters and emissions rates for the ancillary equipment are provided in Table 6-5.

No modifications of the existing Station sources are proposed. The source parameters and emission rates for the existing combustion equipment are presented in Table 6-6. Emission rates are based on the existing permit limits, i.e., maximum allowable emissions.

Worst-case turbine operating conditions were determined based on AERMOD-predicted concentrations for comparison with the SILs, which included the Project emission sources. The worst-case operating condition was based on the operating scenario that results in the highest predicted ground-level air quality impacts. The operating scenarios resulting in the highest predicted concentrations for each pollutant for each averaging period are summarized in Table 6-7.

6.2 AIR QUALITY MODEL SELECTION AND OPTIONS

The USEPA-recommended AERMOD modeling system was used to conduct the dispersion modeling for this analysis. The current versions of the models (AERMOD v15181, AERMET v15181 and AERMAP v11103) were used to model both criteria pollutants and air toxics.

The AERMOD model is a steady-state plume model that incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts. AERMOD includes the treatment of both surface and elevated emission sources in areas of simple and complex terrain. The model can assess sources in either rural or urban settings and calculate concentrations for every hour of meteorological data at user-defined receptors that are allowed to vary with terrain. The AERMOD model has incorporated the latest USEPA building downwash algorithm, the Plume Rise Model Enhancements (PRIME), for the improved treatment of building downwash. PRIME can also account for the stack placement relative to a building, thereby allowing the estimation of impacts in the cavity region near the stack.

AERMOD is designed to operate with two preprocessors: AERMET processes meteorological data for input to AERMOD, and AERMAP processes terrain elevation data and generates receptor information for input to AERMOD. The AERMOD model was selected for the air quality modeling analysis because of several model features that properly simulate the proposed Project dispersion environments, including the:

- ability to model multiple sources;
- ability to calculate simple, complex, and intermediate terrain concentrations;
- ability to estimate cavity impacts;
- use of representative historical hourly average meteorological data; and,
- processing for concentration averaging periods ranging from one hour to one year, as well as 5-year averaging (which is necessary for comparison with the NAAQS).

A complete technical description of the AERMOD model may be found in the User’s Guide for AERMOD (USEPA, 2004a).

Table 6-5: Source Parameters and Emission Rates for the Proposed Ancillary Equipment

Source	Exit Temp. (°F)	Exit Velocity (fps)	Emission Rates (lb/hr)												
			NO_x		CO		PM_{10}		$PM_{2.5}$		SO_2				*Pb*
			1-hr	Ann	1-hr	8-hr	24-hr	Ann	24-hr	Ann	1-hr	3-hr	24-hr	Ann	*24-hr*
Emergency Engine[1]	887.1	139.3	0.338	0.338	4.49	0.561	0.012	0.010	0.012	0.010	0.00026	0.0026	0.00032	0.00026	*1.60e-5*
Fire Water Pump[1]	809.0	127.0	0.031	0.031	1.11	0.139	0.0031	0.0025	0.0031	0.0025	6.18e-5	0.0006	7.53e-5	6.18e-5	*3.75e-6*

[1]For the emergency engine and fire water pump the short-term modeled emission rates are normalized to operate 1 hour within the averaging period. For 1-hour NO_2, 1-hour SO_2 and other pollutant's annual averaging periods, the modeled emission rates were normalized based on 300 hours per year.

Table 6-6: Source Parameters and Emission Rates for the Existing Canal Station Equipment

Source	Exit Temp. (°F)	Exit Velocity (fps)	Emission Rates (lb/hr)												
			NO_x		CO		PM_{10}		$PM_{2.5}$		SO_2				***Pb***
			1-hr	Ann	1-hr	8-hr	24-hr	Ann	24-hr	Ann	1-hr	3-hr	24-hr	Ann	***24-hr***
Canal Unit 1, 2	338.5	116	3112.1	3112.1	10859.3	10859.3	333.2	333.2	333.2	333.2	6728.7	6728.7	6728.7	6728.7	***0.109***
Emergency Gen 1[1]	900	152	0.60	0.60	3.81	0.48	0.05	0.044	0.05	0.044	0.0002	0.0021	0.0003	0.0002	***1.28e-5***
Emergency Gen 2[1]	900	152	0.60	0.60	3.81	0.48	0.05	0.044	0.05	0.044	0.0002	0.0021	0.0003	0.0002	***1.28e-5***
Emerg. Fire Pump[1]	900	267	0.27	0.27	1.75	0.22	0.02	0.019	0.02	0.019	0.0031	0.0299	0.0037	0.0031	***5.63e-6***
Gas Heater	600	8.5	0.64	0.64	0.48	0.48	0.079	0.079	0.079	0.079	0.033	0.033	0.033	0.033	***2.94e-6***

[1]For the emergency engine and fire water pump the short-term modeled emission rates are normalized to operate 1 hour within the averaging period. For 1-hour NO_2, 1-hour SO_2 and other pollutant's annual averaging periods, the modeled emission rates were normalized based on 300 hours per year.

Table 6-7: Results of Proposed Turbine Operating Condition Analysis

Pollutant	Averaging Period	Fuel	Worst-Case Operating Condition[1]
SO_2	1-hr[2,3]	ULSD	Base Load
	3-hr[3]	ULSD	Base Load
	24-hr[4]	ULSD	Base Load
	Annual[2,5]	2940 hours NG 1440 hours ULSD	Minimum Load
PM_{10}	24-hr[4]	ULSD	Startup/shutdown to minimum load
	Annual[2,5]	2940 hours NG 1440 hours ULSD	Minimum Load
$PM_{2.5}$	24-hr[4]	ULSD	Startup/shutdown to minimum load
	Annual[2,5]	2940 hours NG 1440 hours ULSD	Minimum Load
NO_2	1-hr[2,3]	ULSD	Startup/shutdown to minimum load
	Annual[2,5]	2940 hours NG 1440 hours ULSD	Minimum Load
CO	1-hr[3]	ULSD	Startup/shutdown to base load
	8-hr[3]	ULSD	Startup/shutdown to minimum load
Pb	***Rolling 3-month[6]***	***ULSD***	***Base Load***

[1] Worst-case operating conditions for the simple cycle turbine were determined based on AERMOD modeled concentrations for SILs analysis which include the project emission sources (1) simple cycle turbine, (2) fire pump, and (3) emergency generator.

[2] Emergency equipment was included using modeled emission rates that were normalized based on 300 hours per year.

[3] Startup/shutdown conditions for 1-hr, 3-hr, and 8-hr model runs are conservatively defined as 30-min startup and 30-min of normal operations (minimum load for 1-hr NO_2, 8-hr CO and base load for 1-hr CO).

[4] Startup/shutdown conditions for 24-hr model runs refine emissions to six 30-min startups, six 8-min shutdowns, and 22-min minimum load.

[5] Annual average modeling does not evaluate startup/shutdown conditions.

[6] Rolling 3-month average modeling does not evaluate startup/shutdown conditions.

Modeling was performed with all regulatory default options in AERMOD set. The chemical conversion of NO_x into NO_2 is an important factor when assessing NO_2 concentrations. The Ambient Ratio Method (ARM) in AERMOD was used to determine the NO_2 impacts for the Project. Specifically, the USEPA Tier 2 methodology for estimating NO_2 concentrations from total NO_x emissions was implemented. ARM assumes a 75% conversion of NO_x to NO_2 on an annual basis and an 80% conversion of NO_x to NO_2 on a 1-hour basis.

6.3 URBAN/RURAL CLASSIFICATION FOR MODELING

One of the factors affecting input parameters to dispersion models is the presence of either a rural or urban setting near the Project site. Use of the urban options in AERMOD (URBANOPT) depends upon the land use characteristics within 3 kilometers (km) of the source being modeled (Appendix W to 40 CFR Part 51) (USEPA, 2005). Factors that affect the decision if an area is urban, and thus the use of the URBANOPT options in AERMOD, include the extent of vegetated surface area, the water surface area, types of industry and commerce, and building types and heights within this area. Per USEPA guidance, the Auer method of meteorological land use typing scheme was applied to determine whether urban or rural dispersion should be used in the modeling. The Auer land use types are defined in Table 6-8 (Auer, 1978). If the land use types I1, I2, C1, R2 and R3 account for 50% or more of the area within 3 km of the source, then the URBANOPT option could be used in the modeling analysis.

Figure 6-1 shows the 3-km radius around the Project. Observation of the aerial map shows that the area within a 3-km radius of the Project is predominantly rural; therefore, the URBANOPT options were not used in the AERMOD modeling.

Table 6-8: Identification and Classification of Land Use

Type	Use and Structures	Vegetation
I1	Heavy Industrial Major chemical, steel and fabrication industries; generally 3-5 story buildings, flat roofs	Grass and tree growth extremely rare; <5% vegetation
I2	Light-Moderate Industrial Rail yards, truck depots, warehouses, industrial parks, minor fabrications; generally 1-3 story buildings, flat roofs	Very limited grass, trees almost absent; <5% vegetation
C1	Commercial Office and apartment buildings, hotels; >10 story heights, flat roofs	Limited grass and trees; < 15% vegetation
R1	Common Residential Single family dwellings with normal easements; generally one story, pitched roof structures; frequent driveways	Abundant grass lawns and light-moderately wooded; >70% vegetation
R2	Compact Residential Single, some multiple, family dwellings with close spacing; generally <2 story, pitched roof structures; garages (via alley), no driveways	Limited lawn sizes and shade trees; < 30% vegetation
R3	Compact Residential Old multi-family dwellings with close (<2m) lateral separation; generally 2 story, flat roof structures; garages (via alley) and ashpits, no driveways	Limited lawn sizes, old established shade trees; < 35% vegetation
R4	Estate Residential Expansive family dwellings on multi-acre tracts	Abundant grass lawns and lightly wooded; > 95% vegetation
A1	Metropolitan Natural Major municipal, state or federal parks, golf courses, cemeteries, campuses, occasional single story structures	Nearly total grass and lightly wooded; > 95% vegetation
A2	Agricultural; Rural	Local crops (e.g.,corn, soybean); > 95% vegetation
A3	Undeveloped; Uncultivated; wasteland	Mostly wild grasses and weeds, lightly wooded; > 90% vegetation
A4	Undeveloped Rural	Heavily wooded; > 95% vegetation
A5	Water Surfaces: Rivers, lakes	

6.4 GOOD ENGINEERING PRACTICE STACK HEIGHT ANALYSIS

A Good Engineering Practice (GEP) stack height analysis was performed based on the proposed Project design to determine the potential for building-induced aerodynamic downwash for all modeled stacks. The analysis procedures described in USEPA's *Guidelines for Determination of Good Engineering Practice Stack Height* (USEPA, 1985), Stack Height Regulations (40 CFR 51), and current USEPA Model Clearinghouse guidance were used.

The GEP formula height is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground-level concentrations at a closer proximity to the building than would otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided.

GEP stack height is defined as the greater of 65 meters or the formula height. The formula height, as defined by USEPA, is:

$$H_{GEP} = Hb + 1.5L$$

	H_{GEP}	=	$Hb + 1.5L$
Where:	H_{GEP}	=	GEP formula height
	Hb	=	height of adjacent or nearby building or structure
	L	=	lesser of height or maximum projected width of adjacent or nearby building or structure, i.e., the critical dimension

A structure is determined to be "nearby" if the stack is within 5L from the edge of the structure.

The latest version of the USEPA Building Profile Input Program (BPIP-PRIME) was run for all stacks and buildings in the vicinity of the Project to create the building parameter inputs to AERMOD. BPIP-PRIME addresses the entire structure of the wake, from the cavity immediately downwind of the building, to the far wake. Figure 6-2 shows the stack locations as well as the structure footprints and heights input into BPIP-PRIME. A GEP formula height of 491.4 feet (149.8 meters) was calculated for the new turbine stack with the combined structure of the boiler buildings #1 and #2 at the existing Station as the controlling structure. Stack heights for each source modeled are provided in Table 6-1. Each of the stacks modeled is equal to or below its GEP height and, therefore, exhaust emissions have the potential to experience the aerodynamic effects of downwash. As such, wind-direction-specific building parameters generated by BPIP-PRIME were input into AERMOD to account for potential downwash from nearby structures in the dispersion calculations.

6.5 RECEPTOR LOCATIONS FOR MODELING

The receptor grid selected for the AERMOD modeling is sufficient to capture maximum modeled impacts. A nested Cartesian grid was extended out from the Property fence line based on the following spacing and distances:

- at 25-meter intervals along the fence line;
- at 50-meter intervals extending out to 1 km;
- at 100-meter intervals from 1 km to 3 km;
- at 250-meter intervals from 3 km to 5 km;
- at 500-meter intervals from 5 km to 10 km; and,
- at 1,000-meter intervals from 10 km to 20 km.

In addition to the gridded receptors, discrete receptors are placed at locations of schools, daycare centers, hospitals, and nursing homes within 5 km of the Project. Specifically those locations include:

There are identifiable sensitive receptors within 1 km of Canal Generating Station:

1. Dieu's Daycare - Day Care Center (14 Moody Dr. Sandwich, MA)
2. Radius HealthCare Center - Nursing Home (37 MA-6A Sandwich, MA)
3. Sandwich Schoolhouse Preschool (38 Route 6A, Sandwich, MA)

Between 1 km and 5 km from Canal Generating Station, there are 11 identifiable sensitive receptors:

1. Bridgeview Montessori School (885 Sandwich Rd. Sagamore, MA).
2. Ella F Hoxie School (30 Williston Rd. Sagamore Beach, MA)
3. Henry T. Wing School (33 Water St. Sandwich, MA)
4. Sandwich Community School-Early Learning (4 Beale Ave. Sandwich, MA)
5. Little Owl Day Care - Day Care Center (67 Main St. Sandwich, MA)
6. Sandwich Village Preschool - Preschool (159 Main St. Sandwich, MA)
7. Cape Winds Rest Home - Retirement Home (125 Main St. Sandwich, MA)
8. Decatur House Inc - Assisted Living Facility (176 Main St. Sandwich, MA)
9. Joyful Noise Preschool (136 Main St, Sandwich, MA)
10. Rainbow Preschool (80 Old Plymouth Rd, Sagamore Beach)
11. Bourne/Sandwich I Preschool and Borne Sandwich II Preschool (90 Adams St, Sagamore, MA)

The receptor coordinates used in the modeling analysis are in Universal Transverse Mercator (UTM) Zone 19, based on North American Datum (NAD) 83. A total of 8,589 receptors were included in the modeling. The full receptor network is depicted in Figure 6-3 and a close-up of the near field receptors is shown in Figure 6-4.

AERMAP (USEPA, 2004b), AERMOD's terrain preprocessor program, was used to calculate terrain elevations and critical hill heights for each model receptor using National Elevation Data (NED). The 1 arc-second (~30-meter resolution) NED dataset was downloaded from the United States Geological Service (USGS) website (http://seamless.usgs.gov/).

6.6 METEOROLOGICAL DATA FOR MODELING

The meteorological data utilized in the modeling analysis were described in detail in the Modeling Protocol approved by MassDEP. Meteorological data required for AERMOD include hourly values of wind speed, wind direction, and ambient temperature. Five years (2008-2012) of site-specific meteorological data from the nearby Telegraph Hill monitor (approximately 2.9 miles to the south-southeast of the proposed Project) were used in the modeling analyses, along with concurrent surface observations from Barnstable Municipal Airport and upper air data from Chatham Municipal Airport. The meteorological data were processed with AERMET (USEPA, 2004c), the meteorological preprocessor for AERMOD, based on USEPA guidance (USEPA, 2013a), 40 CFR Part 51 Appendix W, the AERSURFACE user's guide (USEPA, 2013b), and other USEPA publications.

The five-year data period selected for this analysis spans the calendar years 2008-2012 because the latest five years (through 2014) from Telegraph Hill had periods that were well below the data completeness requirements for modeling. In particular, data recovery of wind direction for the first quarter of 2013 was less than 60% due to an outage at the tower. However, data for the five consecutive years of 2008–2012 meet data completeness requirements and, therefore, were chosen for this modeling analysis.

The Telegraph Hill monitor records some key measurements at a height much higher than the typical airport 10 meter (33 feet) level:

- wind speed at 145 feet;
- wind direction at 145 feet;
- sigma theta at 145 feet;
- temperature at 10 feet; and
- relative humidity at 10 feet.

The Telegraph Hill data were supplemented, as appropriate, with concurrent surface observations (not including wind data) from Barnstable Municipal Airport (to substitute for missing data) and upper air observations from Chatham Municipal Airport (for upper air data as required by the AERMOD modeling system). The Telegraph Hill Station base of 64.3 meters was used for the potential temperature profile.

AERMET requires specification of site land use characteristics including surface roughness (z_o), albedo (r), and Bowen ratio (B_o). USEPA has developed the AERSURFACE (v13016) tool to determine the site characteristics based on digitized land cover data. AERSURFACE supports the use of land cover data from the USGS National Land Cover Data 1992 archive (NLCD92).[6] The NLCD92 archive provides data at a spatial resolution of 30 meters based on a 21-category classification scheme applied over the continental United States.

AERSURFACE was applied for surface roughness, based on the 1-km radius circular area centered at the Telegraph Hill monitor. The 1-km radius was divided into sectors for the AERSURFACE analysis; each chosen sector has a mix of land uses that is different from that of other selected sectors. The three sectors used for this analysis are: 80˚ – 170˚, 170˚ – 345˚, and 345˚ – 80˚. The determination of the Bowen ratio and albedo are based on a mean value (i.e., no direction or distance dependency) for a representative domain defined by a 10 km by 10 km region centered on the measurement site. For Bowen ratio, the land use values are linked to three categories of surface moisture corresponding to average, wet, and dry conditions. The surface moisture condition for the site may vary depending on the meteorological data period for which the surface characteristics are applied. AERSURFACE applies the surface moisture condition for the entire data period. Therefore, if the surface moisture condition varies significantly across the data period, then AERSURFACE can be applied multiple times to account for those variations. The surface moisture condition for each month was determined by comparing precipitation for the period of data to be processed to the 30-year climatological record, selecting “wet” conditions if precipitation is in the upper 30th-percentile, “dry” conditions if precipitation is in the lower 30th-percentile, and “average” conditions if precipitation is in the middle 40th-percentile. The 30-year precipitation data set used in this modeling was taken from the National Climatic Data Center for Chatham, MA (USC00191386). The monthly designations of surface moisture input to AERSURFACE are summarized in Table 6-9.

Table 6-9: AERSURFACE Bowen Ratio Moisture Condition Designations

Month	Bowen Ratio Category				
	2008	2009	2010	2011	2012
January	Average	Average	Average	Wet	Average
February	Wet	Dry	Average	Average	Dry
March	Average	Average	Wet	Dry	Dry
April	Average	Average	Dry	Average	Dry
May	Wet	Average	Average	Dry	Wet
June	Dry	Average	Average	Average	Dry
July	Average	Wet	Average	Wet	Average
August	Average	Wet	Wet	Average	Average
September	Wet	Average	Wet	Dry	Average
October	Average	Wet	Wet	Wet	Average
November	Average	Dry	Average	Average	Dry
December	Wet	Average	Average	Dry	Wet

There were no winter months during the 2008-2012 time period in which there was measurable snow depth on the ground for more than 50% of the month. As such, in the meteorological data processing, all winter months were modeled as “winter no snow.”

A composite wind rose for the five years of meteorological data used in the modeling analysis is presented in Figure 6-5. The winds are predominantly from the southwest.

[6]http://edcftp.cr.usgs.gov/pub/data/landcover/states/

6.7 BACKGROUND AIR QUALITY DATA

Air quality data collected from the closest, representative, available monitoring stations to the Project site were used to characterize ambient air quality conditions near the proposed Project. Background air quality levels characterize the existing ambient air quality in the vicinity of the proposed Project. NRG operates an ambient monitoring station, Shawme Crowell Monitoring Station, in Shawme Crowell State Park located approximately 1 mile southwest of the Project site. This monitoring site was put into operation to provide data on the existing air quality conditions in the vicinity of the Station. This monitor measures concentrations for SO_2, NO_2, PM_{10}, and $PM_{2.5}$. For background concentrations of CO ***and Pb (lead)***, the Francis School monitor in East Providence (EPA AQS ID 440071010), which is located 43.6 miles to the west-northwest of the Project site was used. Data from both of these monitoring sites represent conservative estimates of the existing ambient air quality. The Shawme-Crowell monitor is a source-specific location designed to capture impacts from the existing Station, which was cumulatively modeled with the Project. The East Providence site is conservative because it is affected by more development, since it is located in a more urban environment than Sandwich. A summary of the background air quality concentrations based on the latest three years (2012-2014) of existing monitoring data are presented in Table 6-10. ***The Pb (lead) data are for 2013–2015.***

As shown in Table 6-10, ambient concentrations of SO_2, NO_2, PM_{10}, and $PM_{2.5}$ measured at the Shawme-Crowell monitor are well below the NAAQS and MAAQS. Ambient concentrations of CO at the closest measurement location in East Providence are also well below the NAAQS/MAAQS.

Table 6-10: Monitored Ambient Air Quality Concentrations and Selected Background Levels

Pollutant	Averaging Period	2012	2013	2014	Background Air Quality (µg/m^3)	NAAQS/MAAQS (µg/m^3)
SO_2 (ppb)	1-Hour	11	9	5	22	196
	3-Hour	22	14	5	58	1,300
	24-Hour	5	4	5	12	365
	Annual	1	2	2	5	80
NO_2 (ppb)	1-Hour	22	20	22	40	188
	Annual	8	8	7	15	100
CO (ppm)	1-Hour	1.5	2.0	1.6	2,346	40,000
	8-Hour	1.0	1.3	1.2	1,495	10,000
PM_{10} (µg/m^3)	24-Hour	23	18	20	23	150
	Annual	9	9	9	9	50
$PM_{2.5}$ (µg/m^3)	24-Hour	12	10	10	11	35
	Annual	5	5	4	5	12
Lead (Pb) (µg/m^3)	***3-Month***	***0.01***	***0.01***	***0.01***	***0.01***	***0.15***

In January 2013, a Court ruling held that use of the $PM_{2.5}$ SIL alone cannot be used to demonstrate compliance with NAAQS. The Court decision does not preclude the use of the SILs for $PM_{2.5}$ entirely, but requires that monitoring data be evaluated to ensure that predicted impacts that are less than the SIL do not result in total concentrations (existing ambient plus project-related contributions) that exceed the NAAQS. Therefore, if there is a sufficient margin (greater than the SIL value) between the representative monitored background concentration in the area and the $PM_{2.5}$ NAAQS, then USEPA believes it would be sufficient to conclude that a proposed source with an impact less than the SIL value will not cause or contribute to a violation of the NAAQS and to forego a more comprehensive modeling analysis for that pollutant for that averaging period (USEPA, 2014). MassDEP believes that this methodology can be extended to all NAAQS pollutants and averaging periods. As shown in Table 6-11, all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, use of the SILs as *de minimis* levels for all pollutants is appropriate.

Table 6-11: Margin between the Monitored Air Quality Concentrations and the NAAQS Compared to the SILs

Pollutant	Averaging Period	Background Concentration (µg/m^3)	NAAQS (µg/m^3)	Delta Concentration (NAAQS minus Background) (µg/m^3)	Significant Impact Level (µg/m^3)
SO_2	1-Hour	22	196	174	7.8
	3-Hour	58	1,300	1,242	25
	24-Hour	12	365	353	5
	Annual	5	80	75	1
NO_2	1-Hour	40	188	148	7.5
	Annual	15	100	85	1
CO	1-Hour	2,346	40,000	37,654	2,000
	8-Hour	1,495	10,000	8,505	500
PM_{10}	24-Hour	23	150	127	5
	Annual	9	50	41	1
$PM_{2.5}$	24-Hour	11	35	24	1.2
	Annual	5	12	7	0.3

(Note: Pb does not have a Significant Impact Level so it is not listed in the Table.

6.8 AIR QUALITY MODELING RESULTS

6.8.1 Significant Impact Level Analysis

The modeled concentrations for criteria pollutants predicted using AERMOD for the proposed Project sources were compared to the applicable SILs. The modeling evaluated a range of operating loads (including SUSD) to assess the proposed Project's impact. SUSD conditions were not evaluated for annual average modeling because these conditions are only expected to last for a short amount of time (less than 30 minutes). The maximum modeled criteria pollutant concentrations are compared to the SILs in Table 6-12. All maximum impacts are predicted at the Station fence-line or within 700 meters of the fence-line for a few pollutants/averaging periods. The results show that maximum modeled concentrations of SO_2 and CO for all averaging periods, and annual NO_2, $PM_{2.5}$, and PM_{10}, are below their corresponding SILs. Maximum modeled concentrations of 24-hour average $PM_{2.5}$ and PM_{10}, and 1-hour NO_2, are above their corresponding SILs (shown in bold in Table 6-12). Therefore, cumulative modeling (see Section 6.8.2) was required for these pollutants/averaging period combinations. Figure 6-6 presents the Significant Impact Area (SIA) for 24-hr PM_{10}, 24-hr $PM_{2.5}$ and 1-hr NO_2. The SIA for 24-hour PM_{10} extends to 1,115 meters; the 24-hour $PM_{2.5}$ SIA extends to 2,903 meters; and, the 1-hour NO_2 SIA extends to 4,750 meters from the Canal 3 stack location.

Table 6-12: Proposed Canal 3 Project Maximum AERMOD Modeled Results Compared to Significant Impact Levels

Pollutant	Avg. Period	Form	Max. Modeled Conc. (μg/m³)	SIL (μg/m³)	% of SIL	Period	Receptor Location[1] (m) (UTME, UTMN, Elev.)
SO_2	1-hr	H1H[2]	0.61	7.8	8%	2008-2012	374615.32, 4625525.14, 3.16
	3-hr	H1H	0.64	25	3%	04/28/11 hr 15	374615.32, 4625525.14, 3.16
	24-hr	H1H	0.40	5	8%	04/28/11 hr 24	374615.32, 4625525.14, 3.16
	Annual	H1H	0.0037	1	0%	2011	375250.00, 4626000.00, 4.00
PM_{10}	24-hr	H1H	**11.98**	5	240%	04/28/11 hr 24	374615.32, 4625525.14, 3.16
	Annual	H1H	0.06	1	6%	2011	375250.00, 4626000.00, 4.00
$PM_{2.5}$	24-hr	H1H[3]	**8.25**	1.2	687%	2008-2012	374615.32, 4625525.14, 3.16
	Ann.	H1H[4]	0.05	0.3	16%	2008-2012	374615.32, 4625525.14, 3.16
NO_2	1-hr	H1H[2,5]	**53.35**	7.5	711%	2008-2012	374425.63, 4625515.76, 2.95
	Annual	H1H[5]	0.71	1	71%	2009	374603.87, 4625282.00, 3.62
CO	1-hr	H1H	197.57	10%	9%	07/18/10 hr 22	374900.00, 4625300.00, 4.71
	8-hr	H1H	45.31	9%	9%	11/10/10 hr 08	374517.68, 4625306.81, 3.12

Note: Impacts denoted in bold font are above the SILs.

[1] All modeled concentrations depicted in this table occur on the facility fence line or within 700-meters of the facility fence line.

[2] High 1st High daily maximum 1-hr concentrations averaged over 5 years.

[3] High 1st High maximum 24-hour concentrations averaged over 5 years.

[4] Maximum annual concentrations averaged over 5 years.

[5] NO_2 estimated by assuming 75% conversion of NO_X to NO_2 for annual concentrations and 80% conversion of NO_X to NO_2 for 1-hour concentrations.

Note: Pb does not have a Significant Impact Level so it is not listed in the Table.

6.8.2 NAAQS Compliance Demonstration

Since the proposed Project is a modification of the existing Station, a compliance demonstration was conducted to ensure that the combined emissions from the existing Station and the proposed new Project will not cause or contribute to a NAAQS violation (MassDEP, 2011).

For the pollutants and averaging periods that have maximum predicted impacts greater than the SILs (24-hour $PM_{2.5}$**,** 24-hour PM_{10} and 1-hour NO_2), cumulative modeling is required. MassDEP modeling guidance indicates that sources within 10 km of the Station that emit significant $PM_{2.5}$, PM_{10}, and NO_x emissions (i.e., > 10 tpy $PM_{2.5}$, >15 tpy PM_{10}, >40 tpy NO_x, based on actual emissions) should be included in the cumulative modeling. A search for facilities was conducted using these criteria and no sources were found within 10 km that satisfy the criteria. Therefore, there are no nearby sources beyond those existing sources at the Station to include in a cumulative modeling analysis. MassDEP has concurred with the finding of no additional sources at other facilities required for a cumulative NAAQS modeling analysis.

The cumulative design value modeled concentrations of the new Project and existing Station were combined with appropriate ambient background concentrations and then compared with the NAAQS. Table 6-13 demonstrates that the predicted total ambient criteria pollutant concentrations (modeled plus background) are below the NAAQS for all pollutants. For reference, the maximum impact from the new sources and existing sources are also shown separately in Table 6-13. Note that these individual concentrations represent their relative maximum impact (in the form of the standard) and are not paired in time and space; therefore, these concentrations do not sum to the "AERMOD Total Modeled Concentration" shown in the table, which reflects the maximum in the form of the standard of the combined impacts (new plus existing) paired in time and space.

Table 6-13: AERMOD Model Results for the New Project and Existing Station Compared to the NAAQS

Pollutant	Avg. Period	Form	AERMOD Modeled Max. Concentration (µg/m³) [1]		AERMOD Total Max. Modeled Conc. (µg/m³)	Back-ground Conc. (µg/m³)	Total Ambient Conc. (µg/m³)	NAAQS (µg/m3)	% of NAAQS	Period[2)]	Receptor Location (m) [2]
			New Sources	Existing Sources							(UTME, UTMN, Elev.)
SO_2	1-hr	H4H[3]	0.49	128.20	128.33	22	150.33	196	77%	2008-2012	375700.00, 4626300.00, 4.35
	3-hr	H2H	0.61	133.70	133.79	58	191.79	1300	15%	06/26/08 hr 12	375400.00, 4626300.00, 4.01
	24-hr	H2H	0.26	45.87	45.92	12	57.92	365	16%	07/08/08 hr 24	375800.00, 4626300.00, 0.51
	Annual	H1H	0.004	4.20	4.20	5	9.20	80	12%	2011	376000.00, 4626700.00, 0.00
PM_{10}	24-hr	H2H	8.53	6.40	8.71	23	31.71	150	21%	12/15/08 hr 24	374615.32, 4625525.14, 3.16
	Annual	H1H	0.06	1.00	1.01	9	10.01	50	20%	2009	373682.47, 4625526.98, 3.77
$PM_{2.5}$	24-hr	H8H[4]	2.43	3.87	3.87	11	14.87	35	42%	2008-2012	373682.47, 4625526.98, 3.77
	Annual	H1H[5]	0.05	0.79	0.79	5	5.79	12	48%	2008-2012	373713.42, 4625597.92, 4.23
NO_2	1-hr	H8H[6,7]	44.28	91.23	91.23	40	131.33	188	70%	2008-2012	373682.47, 4625526.98, 3.77
	Annual	H1H[7]	0.71	10.03	10.04	15	25.04	100	25%	2009	373682.47, 4625526.98, 3.77
CO	1-hr	H2H	195.16	666.81	678.94	2,346	3,024.94	40000	8%	04/11/08 hr 11	374300.00, 4626700.00, 1.71
	8-hr	H2H	42.25	159.51	167.86	1,495	1,662.86	10000	17%	09/22/10 hr 16	375900.00, 4626400.00, 0.00
Pb[8]	***3-month***	***H1H***	***8.51E-04***	***1.43E-03***	***2.28E-03***	***0.01***	***0.012***	***0.15***	***8%***	***03/08/12***	***376500.00, 4627100.00, 0.00***

[1] Modeled concentrations depict impacts from New Sources and Existing Sources relative to their own maximum modeled concentrations. Therefore, the total of the New Sources + Existing Sources does not add up to the "AERMOD Total Modeled Concentration" depicted in this table as these maximum concentrations for the New and Existing sources occur at different receptors and/or different times.
[2] The period and receptor location correspond to the AERMOD Total Modeled Concentration value.
[3] High 4st High daily maximum 1-hr concentrations averaged over 5 years.
[4] High 8th High 24-hour concentrations averaged over 5 years.
[5] Maximum annual concentration averaged over 5 years.
[6] High 8th High daily maximum 1-hr concentrations averaged over 5 years.
[7] NO_2 estimated by assuming 75% conversion of NO_X to NO_2 for annual concentrations and 80% conversion of NO_X to NO_2 for 1-hour concentrations.
[8] Pb impacts are conservatively based on the maximum 24-hr AERMOD modeled concentrations. The "AERMOD Total Modeled Concentration" for Pb is conservatively the sum of the maximum concentrations for the New and Existing source, and the period and receptor are based on the existing source impact.

6.8.3 Secondary $PM_{2.5}$ Assessment

In May 2014, USEPA released "*Guidance for $PM_{2.5}$ Permit Modeling*" (the Guidance), which provides guidance on demonstrating compliance with the NAAQS for $PM_{2.5}$ specifically with regard to consideration of secondarily formed $PM_{2.5}$. In the Guidance, USEPA has defined four "Assessment Case" categories based on a project's potential emissions of direct $PM_{2.5}$ and precursors for potential secondary formation, NO_x and SO_2 (in tpy). The Assessment Case categories identify assessment approaches that are available and appropriate for each case.

The current USEPA dispersion model recommended for near-field $PM_{2.5}$ modeling, AERMOD, does not explicitly account for potential secondary formation of $PM_{2.5}$. Therefore, in addition to the direct $PM_{2.5}$ dispersion modeling analysis, the potential for secondary formation of $PM_{2.5}$ from significant precursor emissions should be assessed in accordance with the Guidance.

Based on the information in Table III-1 of the Guidance, the Project falls into Assessment Case 3[7]. Accordingly, a Case 3 hybrid qualitative/quantitative assessment of potential secondary formation of $PM_{2.5}$ is appropriate.

Based upon the Guidance, a hybrid qualitative/quantitative assessment is deemed appropriate for evaluation of the Project's potential secondary $PM_{2.5}$ because the underlying refined air quality modeling provides a well-developed analysis of both the current background concentrations and the Project's primary $PM_{2.5}$ emissions. Accordingly, a hybrid qualitative/quantitative assessment of the emission source and the atmospheric environment in which the source is located is presented. A quantitative estimate of the projected secondary formation of $PM_{2.5}$ is developed based on the approach described in Appendix D of the Guidance, which incorporates a regional average offset ratio. This assessment supports a determination that secondary $PM_{2.5}$ impacts associated with the source's precursor emissions will not cause or contribute to a violation of the 24-hour or annual $PM_{2.5}$ NAAQS.

Regional $PM_{2.5}$

Particulate matter in the atmosphere is made up of different chemical species (nitrates, sulfates, organic matter, elemental carbon, etc.). NO_x as a gas is considered a precursor pollutant because NO_x emissions can convert to nitrates, a particulate, in the atmosphere. Similarly, SO_2 as a gas can be converted to sulfates in the atmosphere. These conversions involve highly complex shifting between gaseous, liquid and solid phases. They are dependent on atmospheric conditions such as temperature, sunlight, relative humidity and the presence of reactive gases such as O_3, hydrogen peroxide, and NH_3. The formation of secondary $PM_{2.5}$ takes time to occur and, therefore, generally materializes considerably downwind of the precursor emission source. The sulfate formation is considered a stable product; however, the nitrate process is reversible. Equilibrium is established between nitric acid, NH_3 and ammonium nitrate.

As a general matter, the composition of $PM_{2.5}$ varies by season and location across the United States. Nitrates make up a small fraction of the $PM_{2.5}$ in the Northeast. The percentage of nitrates in $PM_{2.5}$ is almost negligible during the summer, increases somewhat in the spring and fall, with the highest percentage of nitrates seen during the winter season. Even during the winter, sulfates and organic matter dominate the $PM_{2.5}$ composition in the Northeast.

For the proposed Project, the background $PM_{2.5}$ monitoring data considered in the air quality analysis are from the Shawme Crowell Monitoring Station located in Shawme Crowell State Park. This monitoring station was specifically established to characterize air quality in the vicinity of the Station. There are co-located $PM_{2.5}$ monitors operating at that monitoring station. Figures 6-7 and 6-8 show a seven-year trend of measured annual $PM_{2.5}$ at the Shawme Crowell site and a 10-year trend at other monitoring locations across the state, respectively. The $PM_{2.5}$ monitoring data show improvement in the ambient air quality on an annual basis over recent years. The same trend is found at other monitoring locations throughout Massachusetts.

A recent Harvard School of Public Health study (Masri, et al., 2015) found that regional sources accounted for 48% of the $PM_{2.5}$ measured at a Boston monitoring site. Hence, the representative background monitoring data for $PM_{2.5}$

[7] Assessment Case 3 applies when direct $PM_{2.5}$ emissions are ≥ 10 tpy and NO_x and/or SO_2 emissions are ≥ 40 tpy.

used in the modeling analysis adequately accounts for secondary contribution from background sources in the region. On the basis of measured data, there is no indication that secondary formation of $PM_{2.5}$ from existing sources in the region is currently causing or contributing to an exceedance of the $PM_{2.5}$ NAAQS on a short-term or annual basis.

Figure 6-9 presents the recent trend of annual NO_2 measurement from Shawme Crowell monitor. The long-term trend of annual NO_2 monitoring data across Massachusetts, as presented on Figure 6-10, shows a pronounced downward trend in concentrations over time. However, as concentrations have decreased to low levels, the trend has stabilized over the past few years across the state as well as at the Shawme Crowell site.

Summary of Primary $PM_{2.5}$ Emissions and Modeling

AERMOD air quality modeling of the primary $PM_{2.5}$ emissions from the proposed Project demonstrates that the predicted 24-hour and annual impacts plus ambient background concentrations are well below the respective NAAQS.

Air quality modeling of the direct $PM_{2.5}$ emissions from the Project plus the ambient background concentration results in a total 24-hour concentration that is approximately 38% of the 24-hour $PM_{2.5}$ NAAQS. The modeled 24-hour impact from the Project represents only approximately 7% of the NAAQS, while the monitored background alone comprises 31% of the NAAQS. On an annual basis, the annual average direct $PM_{2.5}$ modeled impact plus the monitored background accounts for approximately 42% of the annual NAAQS. The modeled concentration attributable to the Project alone accounts for less than 1% of the NAAQS, while the monitored background accounts for more than 41% of the NAAQS.

Therefore, for both the 24-hour standard and the annual standard, there is a very considerable margin allowing for the formation of secondary $PM_{2.5}$ from precursor emissions before an exceedance of the NAAQS would be predicted.

A cumulative modeling analysis was also conducted for direct $PM_{2.5}$ impacts including the proposed Project as well as sources at the existing Station. Air quality modeling of the direct $PM_{2.5}$ emissions from the future Canal Generating Station (new and existing sources) plus the ambient background concentration results in 24-hour impacts that are approximately 42% of the 24-hour $PM_{2.5}$ NAAQS and 48% of the annual $PM_{2.5}$ NAAQS. The monitored background data may also already include the impacts of the existing Station that was also explicitly modeled, so there is some degree of conservative double counting in the analysis. Even with the addition of the direct impacts from the existing Station, there is still a substantial margin available to accommodate any potential secondary formation of $PM_{2.5}$ without approaching the health-protective NAAQS.

Assessment of Secondary $PM_{2.5}$ Emissions

Because the Project is subject to NNSR, it must apply LAER for NO_x. The proposed Project's NO_x emissions are minimized through the use of DLN burners and SCR. SO_2, PM_{10}, and $PM_{2.5}$ emissions will be controlled via the use of clean-burning fuels.

An estimate of the projected secondary formation of $PM_{2.5}$ was developed based on the example described in Appendix D of the Guidance, which incorporates a regional average offset ratio. The method divides the projected emissions by a national ratio of 40 for SO_2 and 200 (eastern states value) for NO_x to determine the total equivalent $PM_{2.5}$ emissions. Then the ratio of the total equivalent $PM_{2.5}$ emissions is divided by the primary $PM_{2.5}$ emissions and the result is used to scale the total modeled primary $PM_{2.5}$ impact to account for the secondary formation of $PM_{2.5}$.

Hence, for the proposed Project:

$$\text{Total Equivalent } PM_{2.5} \text{ (tpy)} = PM_{2.5} + SO_2/40 + NO_x/200$$

$$\text{Total Equivalent } PM_{2.5} \text{ (tpy)} = 99.6 + 11.2/40 + 117.2/200 = 100.5 \text{ tpy}$$

Total Equivalent $PM_{2.5}$ /Primary $PM_{2.5}$ ratio = 100.5 tpy / 99.6 tpy = 1.01

Table 6-14 presents the total $PM_{2.5}$ impacts (24-hour and annual) including the primary modeled $PM_{2.5}$ (from Table 6-13), the estimated secondary $PM_{2.5}$ formed from precursor emissions, and the ambient monitored background. Using the estimation technique provided by USEPA, the secondary formation of $PM_{2.5}$ (from SO_2 and NO_x) is approximately 0.02 µg/m^3 on a 24-hour basis, or approximately 0.06% of the 24-hour NAAQS, and 0.001 µg/m^3 on an annual average basis, or approximately 0.01% of the annual NAAQS.

It should be noted that this analysis is very conservative because the maximum secondary $PM_{2.5}$ impacts will not occur at the same location and time as the maximum direct $PM_{2.5}$ impacts. This is due to the fact that the secondary chemical reactions take time to occur, so the secondary $PM_{2.5}$ impacts would be expected to occur at a greater distance away from the Project than the predicted direct $PM_{2.5}$ impacts.

Table 6-14: Total $PM_{2.5}$ (Primary + Secondary) Impacts Comparison to the NAAQS

Avg. Period	New Source Modeled Primary $PM_{2.5}$ Conc. (µg/m^3)	Equivalent Ratio	Primary plus Secondary $PM_{2.5}$ Conc. (µg/m^3)	Monitored Back-ground (µg/m^3)	Existing Source Contrib.(1) (µg/m^3)	Total $PM_{2.5}$ Impact (µg/m^3)	Standard (µg/m^3)	% of Standard
NAAQS								
24-Hour	2.43	1.01	2.45	11	3.87	17.32	35	49.5%
Annual	0.05	1.01	0.051	5	0.79	5.84	12	48.7%

[1] includes existing Station units

Based on these factors, the above assessment, which has been made in accordance with USEPA Guidance, demonstrates that the $PM_{2.5}$ NAAQS will be protected, taking into account both primary $PM_{2.5}$ impacts and potential contributions from secondary $PM_{2.5}$ due to precursor emissions from the proposed Project.

6.8.4 Air Toxics Analysis

An air quality impact assessment of the non-criteria pollutants (air toxics) emitted from the proposed Project and existing Station sources was conducted. The highest 24-hour average and annual average normalized AERMOD-predicted concentrations were determined across all operating loads and then scaled by the appropriate pollutant emission rates to obtain the predicted concentration of each pollutant. The worst-case impacts were then compared to applicable thresholds. Table 6-15 presents the maximum predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has a guideline 24-hour Threshold Effects Exposure Limit (TEL). The modeled impacts from the proposed Project alone as well as the combined impacts from the proposed Project plus the existing Station are presented. Similarly, Table 6-16 presents the maximum predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has a guideline annual Allowable Ambient Limit (AAL). The results show that air quality impacts from the non-criteria emissions are well below the threshold levels of the corresponding MassDEP AALs and TELs.

Table 6-15: Non-Criteria Pollutant Modeled Concentrations from Proposed Project and Existing Canal Sources for Comparison to Massachusetts TELs

Pollutant	AERMOD Maximum 24-Hr Concentration (µg/m³)		MassDEP 24-hr TEL (µg/m³)	Proposed Project % of TEL	Proposed Project plus Existing % of TEL
	Proposed Project Only(1)	Proposed Project plus Existing(2)			
Acetaldehyde	1.23E-02	2.44E-02	30	0%	0%
Acrolein	1.88E-03	3.06E-03	0.07	3%	4%
Ammonia	1.92E+00	2.14E+00	100	2%	2%
Antimony	0.00E+00	3.28E-03	0.02	0%	16%
Arsenic	1.26E-05	1.01E-03	0.003	0%	34%
Benzene	1.94E-02	3.61E-02	0.6	3%	6%
Beryllium	0.00E+00	2.78E-05	0.001	0%	3%
1,3-Butadiene	4.38E-03	5.00E-03	1.2	0%	0%
Cadmium	1.40E-06	1.20E-03	0.002	0%	60%
Chromium (metal)	5.62E-03	7.72E-03	1.36	0%	1%
Chromium (VI) Compounds	9.77E-07	2.43E-04	0.003	0%	8%
Copper	0.00E+00	1.84E-03	0.54	0%	0%
o-Dichlorobenzene	0.00E+00	1.04E-03	81.74	0%	0%
p-Dichlorobenzene	0.00E+00	1.04E-03	122.61	0%	0%
Ethylbenzene	7.96E-03	8.00E-03	300	0%	0%
Formaldehyde	6.51E-02	1.70E-01	2	3%	8%
Hydrogen Chloride	0.00E+00	2.26E-01	7	0%	3%
Hydrogen Fluoride	0.00E+00	2.49E-02	0.68	0%	4%
Lead	8.51E-04	2.28E-03	0.14	1%	2%
Mercury (elemental)	2.79E-06	2.99E-04	0.14	0%	0%
Mercury (inorganic)	2.79E-06	2.99E-04	0.14	0%	0%
Naphthalene (including 2-methylnaphthalene)	9.91E-03	1.25E-02	14.25	0%	0%
Nickel (metal)	2.58E-03	5.73E-02	0.27	1%	21%
Nickel Oxide	3.28E-03	7.29E-02	0.27	1%	27%
Phosphoric Acid	0.00E+00	1.90E-02	0.27	0%	7%
Propylene Oxide	2.75E-02	8.39E-02	6	0%	1%
Selenium	6.98E-05	5.21E-04	0.54	0%	0%
Sulfuric Acid	4.82E-01	2.43E+00	2.72	18%	89%
Toluene	3.42E-02	4.76E-02	80	0%	0%
1,1,1-Trichloroethane	0.00E+00	1.50E-04	1038.37	0%	0%
Vanadium	0.00E+00	2.18E-02	0.27	0%	8%
Vanadium Pentoxide	0.00E+00	3.90E-02	0.14	0%	28%
Xylenes (m-,o-,p- isomers)	1.72E-02	2.18E-02	11.8	0%	0%

1 Proposed project alone impacts were based on either 24-hrs/day of operation on gas or ULSD for CT3, plus 1-hr/day for the emergency engine and fire water pump.

2 Project impacts were then also combined with existing sources assuming oil firing in Canal Units 1 and 2.

Table 6-16: Non-Criteria Pollutant Modeled Concentrations from Proposed Project and Existing Canal Sources for Comparison to Massachusetts AALs

Pollutant	AERMOD Annual Concentrations (µg/m³)				MassDEP Annual AAL (µg/m³)	Proposed Project % of AAL	Proposed Project plus Existing % of AAL
	Proposed Project Only(1)		Proposed Project plus Existing(2)				
	NG Only	NG + Oil	NG Only	NG + Oil			
Acetaldehyde	3.17E-04	2.84E-04	1.50E-03	1.47E-03	0.4	0%	0%
Acrolein	4.46E-05	3.93E-05	1.88E-04	1.82E-04	0.07	0%	0%
Ammonia	1.71E-02	1.73E-02	3.32E-02	3.34E-02	100	0%	0%
Antimony	0.00E+00	0.00E+00	2.35E-04	2.35E-04	0.02	0%	1%
Arsenic	3.47E-08	7.21E-08	8.37E-05	8.37E-05	0.0003	0%	28%
Benzene	6.55E-04	6.89E-04	2.36E-03	2.40E-03	0.1	1%	2%
Beryllium	0.00E+00	0.00E+00	2.71E-06	2.71E-06	0.0004	0%	1%
1,3-Butadiene	1.15E-05	2.41E-05	7.20E-05	8.46E-05	0.003	1%	3%
Cadmium	3.85E-09	8.01E-09	1.53E-04	1.53E-04	0.0002	0%	76%
Chromium (metal)	1.55E-05	3.23E-05	2.59E-04	2.76E-04	0.68	0%	0%
Chromium (VI) Compounds	2.70E-09	5.61E-09	2.35E-05	2.35E-05	0.0001	0%	23%
Copper	0.00E+00	0.00E+00	1.83E-04	1.83E-04	0.54	0%	0%
o-Dichlorobenzene	0.00E+00	0.00E+00	1.47E-04	1.47E-04	81.74	0%	0%
p-Dichlorobenzene	0.00E+00	0.00E+00	1.47E-04	1.47E-04	0.18	0%	0%
Ethylbenzene	8.04E-05	5.40E-05	8.33E-05	5.69E-05	300	0%	0%
Formaldehyde	9.02E-04	9.09E-04	1.34E-02	1.34E-02	0.08	1%	17%
Hydrogen Chloride	0.00E+00	0.00E+00	1.62E-02	1.62E-02	7	0%	0%
Hydrogen Fluoride	0.00E+00	0.00E+00	1.79E-03	1.79E-03	0.34	0%	1%
Lead	2.35E-06	4.88E-06	1.36E-04	1.39E-04	0.07	0%	0%
Mercury (elemental)	7.70E-09	1.60E-08	3.69E-05	3.69E-05	0.07	0%	0%
Mercury (inorganic)	7.70E-09	1.60E-08	3.69E-05	3.69E-05	0.01	0%	0%
Naphthalene (including 2-methylnaphthalene)	8.88E-05	1.16E-04	3.46E-04	3.73E-04	14.25	0%	0%
Nickel (metal)	7.11E-06	1.48E-05	4.06E-03	4.07E-03	0.18	0%	2%
Nickel Oxide	9.05E-06	1.88E-05	5.17E-03	5.18E-03	0.01	0%	52%
Phosphoric Acid	0.00E+00	0.00E+00	1.36E-03	1.36E-03	0.27	0%	1%
Propylene Oxide	2.89E-03	2.86E-03	8.39E-03	8.37E-03	0.3	1%	3%
Selenium	1.93E-07	4.00E-07	3.41E-05	3.43E-05	0.54	0%	0%
Sulfuric Acid	8.72E-03	8.72E-03	1.74E-01	1.74E-01	2.72	0%	7%
Toluene	5.72E-04	4.64E-04	1.90E-03	1.80E-03	5.31	0%	0%
1,1,1-Trichloroethane	0.00E+00	0.00E+00	1.07E-05	1.07E-05	1038.37	0%	0%
Vanadium	0.00E+00	0.00E+00	1.71E-03	1.71E-03	0.27	0%	1%
Vanadium Pentoxide	0.00E+00	0.00E+00	3.04E-03	3.04E-03	0.03	0%	10%
Xylenes (m-,o-,p- isomers)	3.30E-04	2.77E-04	7.76E-04	7.23E-04	11.8	0%	0%

1 Annual Project impacts includes the greater of either 4,380 hours of gas firing or 2,940 hours gas firing and 1,440 hours ULSD firing for the CT plus 300 hours for the emergency engine and fire water pump.

2 For these two cases, annual Project impacts were then also combined with existing sources assuming oil firing in Units 1 and 2.

6.8.5 Environmental Justice

In 1994, President Clinton issued Executive Order 12898 to "focus federal attention on the environmental and human health effects of federal actions on minority and low-income populations with the goal of achieving environmental protection for all communities." MassDEP has an obligation under the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and USEPA to "identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations."

The Executive Office of Energy and Environmental Affairs (EEA) has identified Environmental Justice neighborhoods as areas with annual median household income equal to or less than 65% of the statewide median income or populations 25% or greater of individuals classified as minority, foreign born, or lacking English language proficiency.

The purpose of an Environmental Justice (EJ) analysis is to determine whether the construction or operation of a proposed facility would have a significant adverse and disproportionate burden on an EJ community. Figure 6-11 shows the EJ communities identified in the MassGIS database in the vicinity of Canal Generating Station. As shown, there are no mapped EJ communities within 5 miles of the Canal Generating Station. As a result, construction and operation of the Facility is not expected to have either a significant or disproportionate impact on minority or low income populations.

Even though the Project is not subject to the requirements of EEA's Environmental Justice Policy, the Project has developed a comprehensive communications plan that includes a number of approaches designed to keep local residents, abutters, businesses and Town of Sandwich officials updated on significant construction milestones and schedules related to the Project. These approaches include:

- ***Electronic mail - As part of public outreach during the permitting process, the Company developed e-mail lists to reach specific targeted audiences, including direct abutters, nearby neighbors within 1 mile, local businesses and key external stakeholders. These lists will be used to deliver targeted traffic and construction messages to affected audiences during the construction phase of the Project.***
- ***Mailings – as part of initial communications announcing and describing the Project, the Company developed and utilized mailing lists to communicate information on public hearings related to the Project. Those lists will be utilized to provide traffic, parking, delivery and construction related updates and notifications during the next phase of Project development.***
- ***Website – The Company has established a website that will be updated as appropriate. From the website, visitors will see the latest information, and can download a printable fact sheet. The website has a provision for visitors to sign up for periodic emails, as well as renderings of how the station will look before and after completion of the Project. The website is being promoted through local media via announcements, emails and phone calls to working journalists and media outlets as well as advertising in selected local publications. The website URL is: www.canalnewgeneration.com***
- ***Routine updates with Town of Sandwich officials – The Company has established routine communication networks with local officials including traffic, fire, police and others regarding the Project particularly concerning traffic management, construction, delivery, noise and all other potential issues of concern to the Town and residents during the construction phase.***

6.8.6 Accidental Release Modeling for NH_3

Canal Generating Station currently uses a 19% solution of aqueous NH_3 for the NO_x control systems on existing Units 1 and 2. Unit 1 has an SCR system, and Unit 2 has a SNCR system. Both these systems use 19% aqueous NH_3 as the NO_x control reagent. Unit 3 will have an SCR system for NO_x control.

The 19% aqueous NH_3 is currently stored in two above-ground 60,000-gallon steel tanks. These tanks are each located within their own concrete containment structure (dike) designed to contain > 110% of the volume of each tank. Each dike is 69.2 feet by 19.1 feet with 7.5-foot-high walls to provide the necessary containment. The dikes are constructed so that the floor of the dike is 4 feet below grade and the top of the dike walls is 3.5 feet above grade. In order to minimize the exposed surface area of any aqueous NH_3 that enters the diked area, passive evaporative controls (plastic spheres) are located in each diked area to reduce the surface area by 90%. In order to minimize further the potential impacts of an unlikely accidental NH_3 release, it is planned to install a structure to enclose the two tanks and diked area. In the event of a tank failure, the structure to enclose the tanks and diked area will be ventilated to the atmosphere through a roof vent.

The following sections detail an off-site consequence analysis that was completed to ensure that in the unlikely event of a complete failure of an aqueous NH_3 tank, off-site consequences of such a release would be minimized and well within safe NH_3 levels.

6.8.6.1 Aqueous Ammonia Emission Calculation

NH_3 in aqueous solution is volatile, and the accidental release of this material would result in some release of NH_3 to the ambient air. Therefore, emissions for a worst-case accidental release scenario have been calculated in accordance with USEPA's Risk Management Program Guidance for Offsite Consequence Analysis (RMP/OCA) (USEPA, 2009).

The RMP/OCA specifies guidance for calculating the release rate of solutions such as aqueous NH_3. For installation with multiple tanks, RMP/OCA specifies that release of the entire contents of the largest single tank should be assumed. Therefore, this analysis assumes that 60,000 gallons of aqueous NH_3 released into the diked area for a single tank. In this case, the surface area of the NH_3 release is constrained by the dike, and further limited by the passive evaporative controls (plastic spheres). The exposed aqueous NH_3 surface area (A) is:

A = (69.2 feet)(19.1 feet)(90% reduction in surface area for plastic spheres)

A = 132.2 square feet

RMP/OCA Equation 3-7 is for the calculation for the NH_3 vapor release rate for a diked area smaller than the maximum pool area, as follows:

QR = (1.4)(LFA)(A)

Where: QR = Release rate (pounds per minute)

1.4 = Wind speed factor for 1.5 meters/second (RMP/OCA Guidance value)

LFA = Liquid Factor Ambient (0.015 per RMP/OCA Appendix B, Table B-3)

A= 132.2 square feet as calculated above

Therefore: QR = (1.4)(0.015)(132.2) = 2.78 lb/minute

For release into buildings, RMP/OCA Equation 3-10 specifies that a mitigation factor of 0.1 may be used.

Per Equation 3-10:

QRB = (0.1)(QR)

Where: QRB = Release rate from building

Therefore: QRB = (0.1)(2.78 lb/minute)

QRB =0.278 lb/minute

A further adjustment is needed for the temperature of the released NH_3. RMP/OCA specifies that the temperature of the released liquid must be the highest daily maximum temperature occurring in the past three years. Based on the meteorological data collected near the Facility Site, this highest daily maximum temperature (T) is 93.4°F (307.3 K).

In accordance with RMP/OCA Appendix D, Equation D-5, the temperature correction factor (TCF) is calculated as follows:

TCF = (VPT)(298)/[(VP298)(T)]

Where: TCFT = Temperature Correction Factor at temperature T

VPT = Vapor pressure at temperature T (7.46 psia at 298 K)

VP298 = Vapor pressure at 298 K (5.10 psia at 298 K)

T = Temperature (K) of released substance

Therefore: TCF = (7.46)(298)/[(5.10)(307.3)]

TCF = 1.42

Therefore, the release rate calculated for the analysis is:

= (0.278 lb/minute)(1.42)(60 minutes/hr) = 23.7 lb/hr

6.8.6.2 Off-site Consequence Analysis

The same AERMOD dispersion model used to predict Facility impacts for comparison with the SILs and NAAQS was used for this analysis. Modeling was used to identify the maximum NH_3 concentration using release conditions assuming a full failure of one of the NH_3 storage tanks. A comparison of the maximum predicted concentration to applicable levels and thresholds is made.

The two aqueous NH_3 storage tanks are to be located in a 25-foot tall structure located at the current location of the tanks. The structure will extend in length and width to cover the existing full diked area. A roof vent which exhausts at the roofline of the structure, was modeled as a volumetric source with an emission rate of 23.7 pounds per hour. The roof vent was centered on the NH_3 storage structure. Emissions from the release were assumed to be at ambient temperature and to be released continuously in order to evaluate the maximum potential concentration across the five years of meteorological data used in the AERMOD model. As described in Section 6.5, a dense network of receptors has been placed both at and adjacent to the fence line.

The concentrations of NH_3 predicted at the fence line and nearby locations are compared against the American Industrial Hygiene Association (AIHA) Emergency Response Planning Guideline Levels (EPRG), EPRG-1, 25 ppm (17,414.1 μg/m^3), and EPRG-2, 150 ppm (104,484.7 μg/m^3). The EPRG-1 is defined as "the maximum airborne concentration below which nearly all individuals could be exposed to for up to 1 hour without experiencing other than mild, transient adverse health effects or perceiving a clearly defined objectionable odor. The EPRG-2 is the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing or developing irreversible or other serious health effects or symptoms, which could impair an individual's ability to take protective action".[8]

The AERMOD modeling assumed a release from the complete failure of one of the aqueous NH_3 tanks inside the structure. The maximum modeled impact presented in Table 6-17 demonstrates that the predicted NH_3 concentrations would be less than the EPRG-1 and EPRG-2 at all locations at or beyond the Station fence line. The maximum 1-hour concentration is predicted at a fence-line receptor, therefore, there are no residences or sensitive receptors that would be subject to NH_3 concentrations approaching the EPRG thresholds.

Therefore, the storage plans for aqueous NH_3 adequately minimize the potential impacts at and beyond the fence line of Canal Generating Station, even in the unlikely event of the complete failure of an aqueous NH_3 tank.

Table 6-17: Maximum Modeled Impact of Accidental Release of Aqueous NH_3

Pollutant	Avg. Period	Predicted Conc. [1] (μg/m^3)	Receptor Location (m) (UTME, UTMN, Elev.)	ERPG-1 (μg/m^3)	ERPG-2 (μg/m^3)	% of ERPG-1	% of ERPG-2
Ammonia (NH_3)	1-hour	4,275.5	374626.83, 4625275.63, 3.61	17,414.1	104,484.7	24.6%	4.1%

[1] High 1st High, the maximum predicted one-hour concentration over 5 years.

[8] http://response.restoration.noaa.gov/erpgs

7.0 NOISE

The Project has been designed to minimize noise impacts to the surrounding community and comply with MassDEP's Noise Regulations and Policy and Town of Sandwich Noise Bylaws. This section presents a sound-level impact analysis for the proposed Project, considering the existing conditions in the Project Site area, the characteristics of the proposed equipment, and mitigation measures that are proposed to be implemented. The objectives of the noise analysis were to:

- identify noise-sensitive receptors in the area that may be affected by the proposed Project;
- describe applicable regulations and the standards to which the Project will be held;
- document existing ambient noise levels in the area;
- identify and characterize the principal noise sources associated with the Project;
- assess the potential impact of construction and operation of the Project on noise levels through the use of a predictive acoustic modeling; and,
- propose and evaluate practicable measures to minimize noise impacts associated with operation of the Project.

7.1 APPLICABLE REGULATORY REQUIREMENTS

Both the MassDEP and the Town of Sandwich have established criteria that address noise. These requirements, which help assure that facilities such as that proposed do not create adverse or nuisance impacts on the community, are discussed below.

7.1.1 MassDEP Regulations and Noise Policy

The MassDEP regulates noise through 310 CMR 7.00, "Air Pollution Control." In these regulations "air contaminant" is defined to include sound, and a condition of "air pollution" includes the presence of an air contaminant in such concentration and duration as to "cause a nuisance" or "unreasonably interfere with the comfortable enjoyment of life and property."

The regulations at 310 CMR 7.10 prohibit "unnecessary emissions" of noise. The MassDEP Division of Air Quality Control Policy Statement 90-001 (February 1, 1990) interprets a violation of this noise regulation to have occurred if sources cause either:

- an increase in the broadband sound pressure level of more than 10 A-weighted decibels (dBA) above the ambient; or,
- a "pure tone" condition.

The ambient background level is defined as the L_{90} level[9] as measured during proposed operating hours. A "pure tone" condition occurs when any octave band sound pressure level exceeds both of the two adjacent octave band sound pressure levels by 3 decibels (dB) or more.

These noise limits are MassDEP policy and are applicable both at the property line and at the nearest noise sensitive areas (residences). In some circumstances, the policy limits can be "waived" by MassDEP at property line locations when the adjacent land uses are not considered sensitive to elevated sound levels and are likely to remain so. The policy limits typically apply at the quietest period analyzed (i.e., nighttime) unless the measurement location is associated with daytime use only. MassDEP does not regulate sound from construction activities or moving motor vehicles.

[9] The L_{90} noise level, often called the "residual" noise level, represents the sound level exceeded 90% of the time. The L_{90} can also be thought of as the level representing the quietest 10% of any time period.

7.1.2 Town of Sandwich Noise Bylaw

The Town of Sandwich Bylaws (Section 3.55 Noise) include a noise nuisance clause and an accompanying complaint resolution procedure, but do not stipulate numerical dB limits. Construction activity is separately regulated through restrictions on construction hours, which are limited to 7 a.m. to 8 p.m., except as allowed by permit. The Town of Sandwich Zoning Bylaw (Section 3420 Noise) limits construction hours to between 7 a.m. and 7 p.m., except as allowed by permit. No numerical dB limits apply to construction activity.

7.2 COMMON MEASURES OF ENVIRONMENTAL SOUND

Sound-level metrics are used to quantify sound-pressure levels and to describe a sound's loudness, duration, and tonal character. A commonly used descriptor is dBA. The A-weighting scale attempts to approximate the human ear's sensitivity to certain frequencies by emphasizing the middle frequencies and de-emphasizing lower and higher frequency sounds. The dB is a logarithmic unit of measure of sound, meaning that a 10 dB change in the sound level roughly corresponds to a doubling or halving of perceived loudness. A 3 dBA change in the sound level is generally defined as being just perceptible to the human ear. A 5 dBA increase or decrease is described as a perceptible change in sound level and is a discernable change in the outdoor noise environment. A 10 dBA increase or decrease is a tenfold increase or decrease in acoustic energy, but is perceived as a doubling or halving of sound (i.e., the average person will judge a 10 dBA change in sound level to be twice or half as loud).

Levels of many sounds change from moment to moment. Some sharp impulses last 1 second or less, while others rise and fall over much longer periods of time. There are various measures of sound pressure designed for different purposes. To describe the background ambient sound level in an area, the L_{90} metric, representing the quietest 10% of any time period, is the basis of MassDEP noise policy limits. The L_{90} is a broadband sound pressure measure, i.e., it includes sounds at all frequencies. Sound-level measurements typically include an analysis of the sound spectrum into its various frequency components. The unit of frequency is Hertz (Hz), measuring the cycles per second of the sound pressure waves and typically the frequency analysis examines nine octave bands from 32 Hz to 8,000 Hz.

Typical sound levels associated with various activities and environments are presented in Table 7-1.

Table 7-1: Sound Levels of Typical Noise Sources and Acoustic Environments

Noise Source or Activity	Sound Level (dBA)	Subjective Impression
Vacuum cleaner (10 feet)	70	Moderate
Passenger car at 65 mph (25 feet)	65	
Large store air-conditioning unit (20 feet)	60	
Light auto traffic (100 feet)	50	Quiet
Quiet rural residential area with no activity	45	
Bedroom or quiet living room Bird calls	40	Faint
Typical wilderness area	35	
Quiet library, soft whisper (15 feet)	30	Very quiet
Wilderness with no wind or animal activity	25	Extremely quiet
High-quality recording studio	20	
Acoustic test chamber	10	Just audible
	0	Threshold of hearing

7.3 EXISTING AMBIENT NOISE LEVELS

The area in the vicinity of the Project Site is largely mixed-use, with the closest sensitive receptors being the residences to the south on Briarwood Avenue and to the southeast on Freezer Road. The Project Site borders a marina, the Cape Cod Canal, industrial properties, and railroad tracks. Industrial uses, including an oil tank farm, and several industrial buildings are located along Canal Service Road, a public walkway maintained by the USACE. Large diesel-powered barges and vessels move through the Cape Cod Canal at all hours and all seasons. The Scusset Beach State Reservation is located across the Cape Cod Canal. Figure 7-1 shows the Project Site and the locations where short-term (ST) and long-term (LT) baseline sound level measurements were conducted. The measurement locations are summarized in Table 7-2. These measurement locations are the residential dwellings, commercial buildings, and public areas around the Project Site, and are representative of the receptors that will be sensitive to noise emissions from the Project. The acoustic assessment utilizes these measurement locations as the noise receptors to evaluate the impact of noise from the Project. In addition, two LT monitors were positioned on the Project Site to document diurnal variation of noise levels. As shown on Figure 7-1, LT-1 was positioned at the southwest corner of the Project Site and LT-2 positioned at the northeast corner of the Project Site.

Table 7-2: Baseline Sound Measurement Locations

ID	Location
ST-1	1 Freezer Rd, Sandwich, MA
ST-2	55 Tupper Rd, Sandwich, MA
ST-3	***14 Gallo*** Rd, Sandwich, MA (Marina)
ST-4	11 Tupper Rd, Sandwich, MA
ST-5	Canal Service Road Walkway
ST-6	14 Town Neck Rd, Sandwich, MA
ST-7	Canal Service Road Walkway
LT-1	Southwest Project Site boundary
LT-2	Northeast Project Site boundary

Background sound data for all of the short-term locations except ST-7 are based on ambient sound measurements made on December 15-16, 2014. The weather conditions during these measurements were seasonal and were suitable for ambient sound measurements. The conditions varied from an air temperature of 40°F, sunny sky, and light breeze from the northwest during the day to an air temperature of 33°F, overcast sky, and slight breeze from the northwest during the night. Data for ST-1, ST-2 and ST-3 were measured manually over 15 minute intervals during the day and night using a hand-held Rion Model NA-28 Class 1 Precision Sound Level Meter and Octave Band Analyzer. The daytime measurements were made between 11:00 AM and 3:30 PM, and the nighttime measurements were made between 11:00 PM and 2:00 AM.

Background sound data for ST-4, ST-5 and ST-6 are based on continuous 24-hr measurement data from approximately noon on December 15, 2014 to noon on December 16, 2014. Rion Model NL-52 Class 1 Precision Sound Level Meters were programmed to collect overall A-weighted sound levels and spectral data (1/3-octave band sound pressure levels) and to store statistical values (L_{1}, L_{10}, L_{50}, L_{90}, and L_{eq}) at 15-minute intervals. These continuous monitors characterized the variation in the residual (L_{90}) ambient sound levels at ST-4, ST-5, and ST-6 during the daytime and nighttime periods. The microphone for each continuous monitor was fitted with a windscreen and mounted on a tripod at a nominal height of 4 ft.

For the December 15-16 surveys, both the hand-held and continuous monitors were laboratory-calibrated within the past year and their calibrations were checked with an acoustic calibrator in the field before and after the surveys.

Background sound data (nighttime levels) for ST-7 are based on ambient sound measurements made on June 12, 2015, from 12:30 AM to 1:00 AM. The weather conditions were clear with light winds and were suitable for ambient sound measurements. The air temperature was in the range of 65°F. A sound level analyzer meeting the requirements of ANSI S1.4-1983 and ANSI S1.43-1997 for precision Type 1 sound level analyzers was used. The microphone was fitted with a windscreen. All one-third octave band measurements included the frequencies from 16 Hz through 16,000 Hz. The sound level analyzer was calibrated in the field immediately before and after the measurement period. As required by ANSI S12.9/Part 3, a precision calibrator that complies with the accuracy requirements of ANSI S1.40 was utilized.

The acoustic environment in the area surrounding the Project results from numerous sources. Late at night, the dominant sound sources noted during the field measurement program were roadway traffic, nearby industrial operations including trucking, rail traffic, and aircraft overhead.

Additional spot measurements were taken on the Project Site and in the vicinity of key equipment components. These measurements were taken with both existing Units 1 and 2 operating under various loads for acoustic model verification purposes. Ambient levels measured while Units 1 and 2 were operating ranged from 41 to 53 dBA.

No noise complaints associated with the Station have been received over the past several years.

Sound-level monitoring, completed in December 2014 in the vicinity of the Property with neither of the existing Station units operating, shows existing nighttime L_{90} levels were in the range of 33 to 41 dBA. The sound sources that were observed during this survey included: distant and local road traffic; birds; pedestrian traffic; leaf rustle; aircraft overflights; shipping vessel movements; and roadway noise. Auxiliary equipment housed at the communication tower control house was also audible at several measurement locations.

7.4 NOISE IMPACT ANALYSIS

7.4.1 Project Noise Sources and Reference Sound Data

The primary sources of sound associated with the proposed Project include one GE 7HA.02 CTG, or equivalent unit, and related equipment, including: air pollution control equipment; natural gas pre-heater and compressor; evaporative inlet air cooling system; tempering air fan system; electrical transformers; blowers; pumps; and ventilation fans. The noise impact analysis conservatively assumes all of the proposed equipment to be operating simultaneously at full-load.

Sound-level data for the GE 7HA.02 CTG package were provided by GE. The sound power level (abbreviated "L_w" or PWL) is defined as ten times the logarithm (to the base 10) of the ratio of a given sound power to the reference sound power of one picowatt. Sound power is defined as the rate per unit time at which sound energy is radiated from a source and is expressed in terms of watts. Sound data for the various ancillary components of the Project were supplied either by Canal 3, or obtained from Tetra Tech's project database. Table 7-3 lists the sound power level of each continuous noise source by octave band center frequency used in the acoustic model.

Table 7-3: Project Noise Source Sound Power Levels

Item	Sound Power Level by Octave Band Center Frequency (dB)									Broadband Level (dBA)
	31.5	63	125	250	500	1k	2k	4k	8k	
Exhaust Stack- Outlet Opening	128	132	128	122	110	97	95	95	95	117
Total SCR System	123	123	122	115	105	99	92	75	58	111
7HA.02 Inlet Ducting (including Filter House Casing Breakout)	108	104	108	112	106	94	108	96	72	111
7HA.02 Turbine Compartment	107	104	101	96	97	98	101	106	94	109
Generator Step-Up (GSU) Transformer	106	106	107	110	107	96	91	87	83	107
Lower Section/Base of Exhaust Stack	118	115	117	111	99	93	85	65	46	106
7HA.02 Generator (7FH2)	99	105	107	96	102	100	100	94	84	106
Turbine Compartment Vent Fans	102	102	110	101	98	95	94	98	95	104
SCR Tempering Air System- Fan Inlet Opening	118	121	114	98	80	73	97	96	89	104
Upper Section of Exhaust Stack	117	113	115	108	95	85	79	64	46	103
Cooling Fan Module (8 fans)	109	111	109	104	101	98	90	86	82	103
7HA.02 Lube Oil Module	101	102	99	98	97	96	96	97	88	103
7HA.02 Inlet Plenum	102	99	98	93	94	97	97	94	89	102
7HA.02 Load Compartment	87	93	93	87	87	93	94	88	78	98
7HA.02 Exhaust Diffuser	106	113	97	93	87	84	86	88	75	94

7.4.2 Cadna-A® Sound Model

The acoustical modeling for the proposed Project was conducted with the Cadna-A® sound model from DataKustik GmbH. The outdoor noise propagation model is based on ISO 9613, Part 1: “Calculation of the absorption of sound by the atmosphere,” (1993) and Part 2: “General method of calculation,” (1996). It is used by acoustical engineers to describe accurately noise emission and propagation from complex facilities and in most cases yields conservative results of operational noise levels in the surrounding community. Model predictions are accurate to within 1 dB of calculations based on the ISO 9613 standard.

ISO 9613 was used to calculate propagation and attenuation of sound energy with distance, surface and building reflection, and shielding effects by barriers, buildings, and ground topography. Offsite topography was determined using USGS digital elevation data for the study area. The noise model propagation calculation parameters are summarized in Table 7-4.

Table 7-4: Acoustic Modeling Parameters

Model Input	Parameter Value
Standards	ISO 9613-2, Acoustics – Attenuation of sound during propagation outdoors.
Terrain of Site Area	Per site grading plan and USGS topography
Temperature	50°F
Relative Humidity	70%
Wind	2 to 11 mph, from facility to receptor*
Ground Attenuation	G = 0.5
Number of Sound Reflections	2
Receptor Height	5 feet above ground
Operation Condition	Full load, doors close
Reflection Loss	2 dB – indicates reduction in acoustic energy due to reflection
Reflections	Two reflections (from buildings and obstacles) were allowed for individual acoustic rays during propagation calculations
*Propagation calculations under the ISO 9613 standard incorporate the effects of downwind propagation (from facility to receptor) with wind speeds of 1 to 5 meters/second (3.6 to 18 km/hour) measured at a height of 3 to 11 meters above the ground.	

Cadna-A® allows for three basic types of sound sources to be introduced into the model: point, line, and area sources. Each noise-radiating element was modeled based on its noise emission pattern. Small dimension sources, such as building ventilation fans, which radiate sound hemispherically, were modeled as point sources. Linear-shaped features, such as ducts and pipelines, were modeled as line sources. Larger dimensional sources, such as the exhaust diffuser and building walls, were modeled as area sources.

Noise walls, equipment enclosures, stacks, and plant equipment were modeled as solid structures because diffracted paths around and over structures tend to reduce noise levels. The interaction between sound sources and structures was also taken into account with reflection loss. The storage tanks were modeled as obstacles impeding noise propagation. The reflective characteristic of the structure is quantified by its reflection loss, which is typically defined as smooth façade from which the reflected sound energy is 2 dB less than the incident sound energy. Transformer fire walls and sound barriers were modeled as either reflective or absorptive barriers.

Ground absorption rates are described by a numerical coefficient. For hard-packed dirt or pavement, the absorption coefficient is defined as G = 0 to account for reduced sound attenuation and higher reflectivity. In contrast, ground covered in vegetation, including suburban lawns, are acoustically absorptive and aid in sound attenuation, i.e., G = 1.0. For the acoustic modeling analysis, a mixed ground absorption rate of G = 0.5 was determined appropriately representative for the area surrounding the Project.

The Project's general arrangement was directly imported into the acoustic model so that on-site equipment could be easily identified, enclosures and structures could be added, and sound power data could be assigned to sources as appropriate.

7.4.3 Predicted Project Sound Levels

7.4.3.1 Construction Impacts

The construction of Project will result in a temporary increase in sound levels near the Project Site. The construction process will require the use of equipment that could be audible from off-site locations at certain times. Project construction consists of site clearing, excavation, foundation work, steel erection, and finishing work. Work on these phases will overlap. No blasting or pile driving will be performed.

Noise levels resulting from construction activities vary greatly depending on: the type of equipment; the specific equipment model; the operations being performed; and the overall condition of the equipment. USEPA (1971) has published data on the average sound levels (L_{eq}) for typical construction phases. Following the USEPA method, sound levels were projected from the acoustic center of the Project footprint to the closest noise sensitive areas. This calculation conservatively assumes all construction equipment operating concurrently onsite for the specified construction phase and no sound attenuation for ground absorption or onsite shielding by the existing buildings or structures.

The results of these calculations are presented in Table 7-5 and show estimated construction sound levels at the nearest residential locations would be between 44 and 66 dBA. ***C***onstruction sound, while audible, ***is*** not be expected to create a noise nuisance condition.

Construction equipment used on the Project Site will comply with the construction-hour limits specified in the Town of Sandwich Zoning Bylaws (Section 3420 of the Town Bylaw). Per the Bylaw, construction will occur between 7 a.m. and 7 p.m., except as other hours are allowed by permit from the Town.

Table 7-5: Construction Sound Levels (dB)

Construction Phase	50 Feet from Source (L_{eq})	At Closest Noise Sensitive Areas (L_{eq})
Clearing	84	50 to 59
Excavation	91	57 to 66
Foundations	78	44 to 53
Erection	85	51 to 60
Finishing	89	55 to 64

7.4.3.2 Project Impacts

The predicted maximum sound level impacts at the closest noise-sensitive locations were added to the measured existing ambient L_{90} levels to determine the net increase and to assess conformance with the MassDEP Noise Policy. As shown in Table 7-6, the Project is expected to increase the lowest nighttime background sound levels by 1 to 7 dBA at the nearest residences and marina area. These potential increases in background sound levels correspond only to the period from midnight to 4 a.m., when background sound levels are very low.

Background L_{90} levels were found to be 5 to 10 dBA higher during the daytime hours than the aforementioned nighttime minimum. Therefore, the Project is expected to increase background sound levels during the daytime by less than 6 dBA at the closest residence on Freezer Road.

Table 7-6: Predicted Nighttime L_{90} Sound Levels in the Vicinity of the Proposed Project (dBA)

Location	Measured Ambient (No Units Operating)	Mitigated Unit 3 Sound Level Contribution	Modeling Results (Unit 3 Plus Existing Ambient)	Increase Above Existing Ambient
ST-1	41	46	47	6
ST-2	40	46	47	7
ST-3	40	40	43	3
ST-4	36	***35***	***39***	***3***
ST-5	33	***30***	***35***	***2***
ST-6	34	38	39	5
ST-7	39	***35***	41	2

Modeling results also indicate that the Project will not result in a pure tone condition. This fact, in conjunction with the results presented in Table 7-6, demonstrates that the Project will fully comply with the MassDEP Noise Policy.

7.4.3.3 Cumulative Impacts

An engineering review was completed to assess the cumulative sound impacts from the operation of the existing Units 1 and 2 combined with the proposed Project. The cumulative analysis results are provided in Table 7-7 and show future sound levels (Existing Units 1 and 2 + Proposed Project + Background) that demonstrate a net increase above measured background nighttime L_{90} sound levels of no more than 10 dBA at all receptor locations. ***Improvements to Units 1 and 2 will be made to ensure minimization of cumulative noise impacts. These may include:***

- ***Installing*** lagging or ***partial*** enclosures for the Unit 1 ***and 2*** hopper vibrator systems;
- ***Refurbishment of*** lined inlet ***and noise baffling system*** for Unit ***2*** FD fans; and
- ***Installation of noise barrier walls for the Units I and 2 service and mai n transformers*** .

It should be noted that the simultaneous operation of Units 1 and 2 and the proposed Project would be expected to occur very infrequently, as none of the units are expected to provide baseload power to the grid.

Table 7-7: Comparison of Nighttime L_{90} in the Vicinity of Canal Generating Station – Existing Units 1 & 2 and Proposed Unit 3 (dBA)

Location	Measured Ambient (No Units Operating)	Cumulative Modeling Results (Units 1, 2, and 3 Operating)	Increase Above Background
ST-1	41	50	9
ST-2	40	50	10
ST-3	40	***46***	***6***
ST-4	36	***43***	***7***
ST-5	33	***42***	***9***
ST-6	34	***42***	***8***
ST-7	39	***49***	***10***

Compliance is demonstrated with the MassDEP Noise Policy.

7.5 PROPOSED MITIGATION MEASURES

7.5.1 Project Construction

Reasonable efforts will be made to minimize the impact of noise resulting from construction activities. Following is a list of noise mitigation measures are planned.

- Construction activities that produce significant noise will be limited to the daytime hours listed in the Town of Sandwich Zoning Bylaw.
- Construction equipment will be well-maintained and vehicles using internal combustion engines equipped with mufflers will be routinely checked to ensure they are in good working order.
- Quieter-type adjustable backup alarms will be used for vehicles.
- Portable noise barriers and enclosures will be used when appropriate.
- Noisy equipment on-site will be located as far from possible from sensitive areas.
- A noise complaint hotline will be made available to address any noise-related issues.

7.5.2 Project Operation

Based on the results of the noise assessment, a comprehensive set of noise mitigation measures has been incorporated into the design of the Project to minimize noise impacts. Note that the selected mitigation reflected in this acoustic analysis is intended to reflect the feasibility of achieving the resulting level of impact; final design may incorporate different mitigation in order to achieve the same objective.

The principal noise mitigation measures that will be incorporated into the Project design are as follows:

- increased casing thickness for the SCR and an acoustic shroud that will envelop the exhaust gas diffuser and the transition duct from the GT exhaust to the SCR casing;
- additional exhaust silencing to reduce stack outlet noise;
- enclosures around the gas turbine, lube oil skid, and generator;
- lowered height of the tempering air fan inlet plenum box from 50 feet above grade to 35 feet above grade;
- orientation of the tempering air inlet away from sensitive receptor locations;
- a noise barrier near the tempering air fans;
- low-noise fans for the cooling module, with a noise barrier near the module;
- acoustically treated walls for the fuel gas compressor enclosure;
- low-noise generator step-up transformer; and
- turbine inlets equipped with an 8-foot silencer with an acoustically lined weather hood.

The above noise mitigation measures were developed to reduce Project sound levels at the evaluated receptor locations. Details of the proposed mitigation plan are described below.

7.5.2.1 Cooling Module

Mitigation for the cooling module includes a specified sound power level of 90 dBA per fan. A sound power level of 90 dBA would be considered “low-noise” for a large-diameter fan. In addition to low-noise fans, a noise barrier wall approximately 25-30 feet tall will be constructed.

7.5.2.2 SCR Tempering Air System

Mitigation of the SCR tempering air (TA) fans will be incorporated into the design to reduce sound levels at Locations ST-1 and ST-2. The TA system for the GE 7HA.02 CTG incorporates two 100% fans (approximately 625,000 ACFM per fan); only one fan is required to support operation of the unit. A low noise unit, with a sound pressure level of approximately 83 dBA at 1 meter from the inlet plane will be specified. Although the fan scroll housings will be located at ground level, the top of the fan inlet plenum, which is typically situated 50 feet above grade, will be lowered to 35 feet above grade. A sound barrier will be constructed adjacent to the TA system, approximately 10 feet taller than the top of the plenum box to shield adequately both components.

7.5.2.3 SCR Casing

A standard SCR casing would typically have a casing thickness of ¼ inch and a 6-inch-thick layer of insulation. The Project design will incorporate ½-inch thick casing for much of the larger SCR sections. In addition, an external shroud to wrap the SCR has been incorporated. The combined sound transmission loss (combination of thicker casing and/or external shroud) will perform such that the sound pressure level at 1 meter from the SCR/Catalyst casing does not exceed approximately 62 dBA.

7.5.2.4 Combustion Turbine Enclosure

The combustion turbine compartment, exhaust diffuser, lube oil system, and turbine inlet plenum will be placed inside an acoustically treated enclosure with a Sound Transmission Loss (STC) rating of 39. The resulting sound pressure level at 1 meter from the surface of the combustion turbine enclosure is 65 dBA.

7.5.2.5 Generator Enclosure

The generator will also be located within an enclosure with walls achieving an STC rating of 32. The resulting sound pressure level at 1 meter from the surface of the generator enclosure will also be 65 dBA. The generator enclosure will require a less robust wall system than the combustion turbine enclosure, because sound pressure levels inside the generator enclosure will be lower than in the combustion turbine enclosure.

7.5.2.6 Fuel Gas Compressor Enclosure

Fuel gas compressor operation only occurs when pipeline pressure is lower than required pressure. The average sound pressure level inside the compressor enclosure is expected to be approximately 97 dBA. Mitigation for the compressor is an enclosure with an STC rating of 45 and has been added primarily to address noise levels at ST-7 (pedestrian walkway).

7.5.2.7 Turbine Inlet Filter Face

The CTG air inlets will include additional silencing beyond standard manufacturer specifications of PWL 105 dBA. A sound power level of PWL 92 dBA will be achieved for the gas turbine inlet filter house face. This corresponds to the standard GE 8-foot-long inlet silencer, but with an acoustically lined weather hood on the filter house.

7.5.2.8 Ventilation

The enclosures proposed above will require ventilation. The ventilation fans are assumed to be no higher than 3 feet above the rooftop and have a sound power level (per fan opening) no higher than PWL of 85 dBA.

7.5.3 Existing Canal Generating Station Equipment

Improvements to Units 1 and 2 will be made to ensure minimization of cumulative noise impacts. These may include:

- ***installing*** lagging or ***partial*** enclosures for the Unit 1 ***and 2*** hopper vibrator systems;
- ***refurbishment of lined inlet and noise baffling system for the Unit 2 FD fans; and***
- ***installation of noise barrier walls for the Units I and 2 service and mai n transformers*** .

It should be noted that the simultaneous operation of Units 1 and 2 and proposed Project would be expected to occur very infrequently as none of the units are expected to provide baseload power to the grid.

7.5.4 Best Available Noise Control Technology Analysis

A Best Available Noise Control Technology (BANCT) analysis has been prepared that considers three Project noise control options: Cases A, B, and C. Case A involves mitigating the Project to ensure an increase of no greater than 10 dBA above existing ambient levels at any evaluated receptor; Case B is the proposed design; and Case C evaluates the cost-effectiveness of additional noise mitigation beyond that proposed. The total sound levels evaluated include the contributions of both the Project and background sound.

Case C would provide up to a 3-dBA reduction over Case B at some receptors, but as little as a 1-dBA reduction in the more highly populated Town Neck area east of the plant. Since 3 dBA is generally considered to be a barely perceptible change in sound levels, Case C would not provide a noticeable reduction in community sound levels, but would cost an additional $7 million.

Case B, which fully complies with MassDEP and Town of Sandwich noise requirements, represents the most reasonable balance between the cost of noise control and reduction in facility sound.

Table 7-8 outlines the plant noise controls and estimated costs for Cases A, B, and C. The costs are not inclusive of anticipated additional noise mitigation associated with Units 1 and 2.

Table 7-8: Description of Noise Control Options for Unit 3

Level of Control	Treatments	Estimated Cost
A (Baseline)	Acoustical building for CTGs and auxiliary equipment; mufflers for vent systems; mufflers for CT air inlets; mufflers for CT exhaust systems; TA fan barrier; low-noise transformers; additional stack silencing; and a shroud encompassing the SCR and exhaust diffuser.	$7,750,000
B (Proposed Design)	Same as A, but adding an enclosure for gas compressors and a lower height and barrier for fin-fan cooler.	$11,020,000
C (High Attenuation)	Same as B, but adding a much larger CTG building that encloses the entire SCR and exhaust diffuser, and addition of fin fan cooler baffle silencers.	$18,250,000

As shown in Table 7-8, substantial noise mitigation measures have been incorporated into the design of the proposed Project to minimize noise impacts on the surrounding community. Results of a complete sound level assessment demonstrate that noise levels from the Project will comply with the requirements set forth in the MassDEP Noise Policy and the Town of Sandwich Noise Bylaw.

7.6 POST-CONSTRUCTION NOISE MONITORING

Post-construction noise monitoring will be conducted to demonstrate compliance with the noise impact analysis results. Canal 3 will require noise guarantees from major equipment vendors and the Engineering, Procurement and Construction contractor. Prior to accepting the Project, Canal 3 will require a noise monitoring-based compliance demonstration. This will entail near-field measurements of sound levels from major equipment sources and at the Property boundary. This enables isolation of sound contributions from the Project and existing Units 1 and 2, without interference from variable non-Project-related sources.

The measured near-field sound levels will be used to confirm compliance with the noise impact analysis levels.

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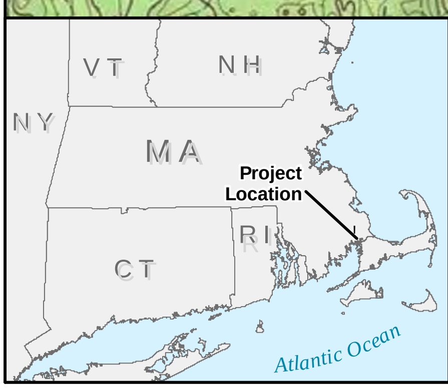
FIGURES



Legend

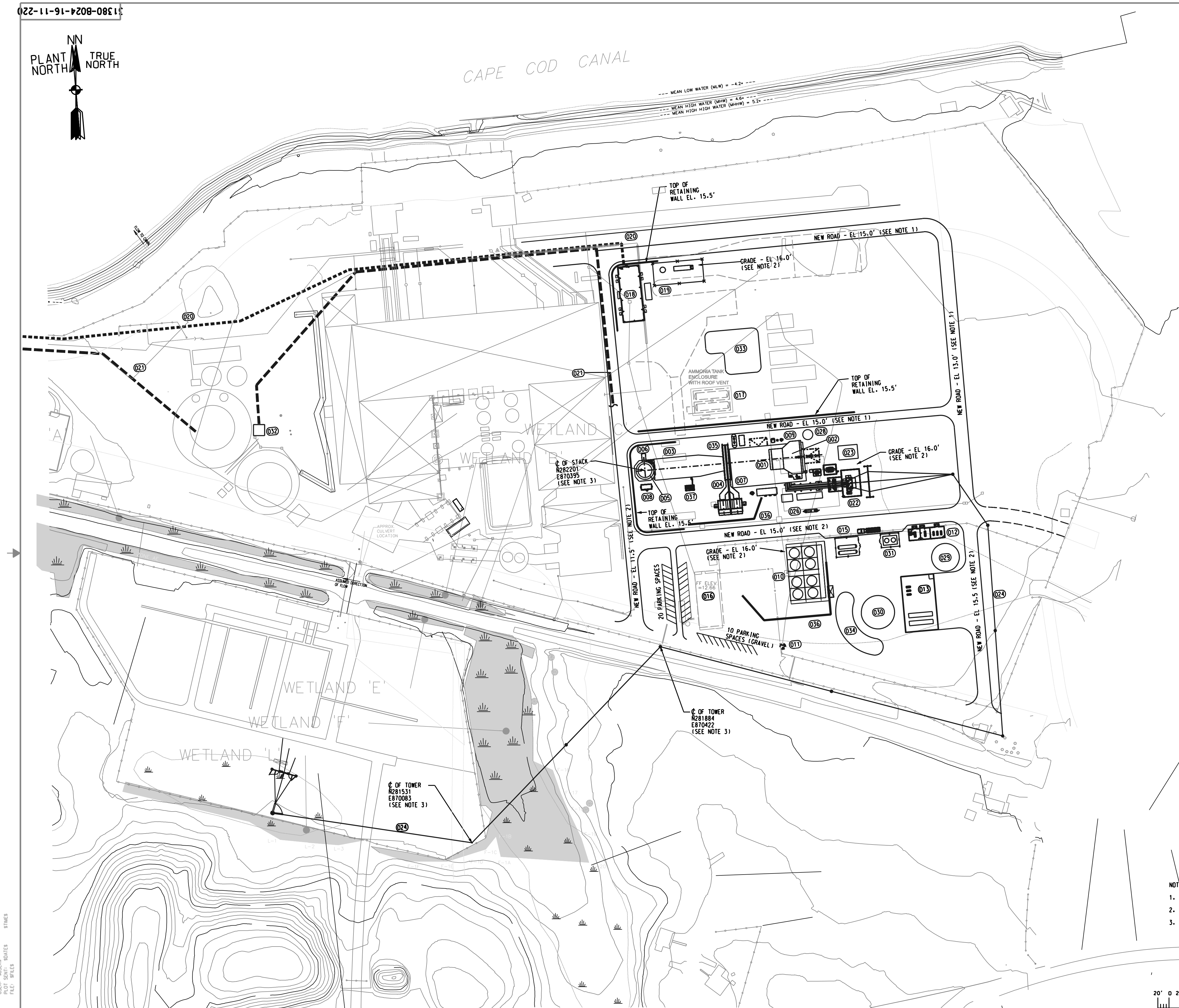
Property

Facility Site

0 500 1,000 2,000 Feet

Figure 2-1
Site Location

NRG Canal 3 Development LLC
Sandwich, Massachusetts



LEGEND

001 GAS TURBINE GE 7HA.02 (w/ACOUSTICAL ENCLOSURE)
002 GENERATOR
003 SCR/CO2 CATALYST (w/ACOUSTICAL SHROUD)
004 TEMPERING/PURGE FANS
005 STACK
006 EMERGENCY DIESEL GENERATOR
007 LUBE OIL SKID
008 CEMS
009 COMPRESSED AIR SYSTEM
010 COOLING FAN MODULE
011 EXISTING WELL
012 SERVICE WATER/FIRE PROTECTION PUMP HOUSE
013 DEMINERALIZED WATER SYSTEM
014 DELETED
015 HYDROGEN STORAGE AREA
016 EXISTING TRAINING BLDG. / NEW CONTROL RM.
017 EXISTING AMMONIA STORAGE AREA
018 GAS COMPRESSOR
019 GAS PRE-HEATER AREA
020 NEW GAS LINE
021 NEW FUEL OIL LINE
022 GENERATOR STEP-UP TRANSFORMER (GSU)
023 POWER DISTRIBUTION CENTER (PDC)
024 TRANSMISSION LINES
025 DELETED
026 OIL WATER SEPARATOR
027 DELETED
028 EVAPORATOR COOLER BLOWDOWN COLLECTION TANK
029 SERVICE WATER/FIRE WATER TANK
030 DEMINERALIZED WATER TANK
031 CO2 STORAGE AREA
032 FUEL OIL PUMP HOUSE
033 INFILTRATION BASIN 1
034 INFILTRATION BASIN 2
035 UNDERGROUND 4,000 GALLON CT WATER-WASH TANK
036 ACOUSTICAL WALL
037 AMMONIA VAPORIZATION SKID

NOTES:

1. ROAD MAY NEED TO BE ADJUSTED AFTER SURVEY LOCATION OF RAILWAY TRACKS.
2. ELEVATIONS MAY NEED SOME ADJUSTMENT AS MORE INFORMATION BECOMES AVAILABLE.
3. THE LOCATION OF THE STACK IS BASED ON THE MASSACHUSETTS STATE PLANE SYSTEM, (NAD27, DATUM) FOR THE HORIZONTAL COORDINATES. THE GRID PRESENTED WAS CREATED FROM IMAGE FILES RECEIVED FROM NRG. COORDINATE LOCATION REQUIRES RECHECK WHEN SURVEY DATA IS OBTAINED. MORE DETAILED DESIGN OF THE SITE ARRANGEMENT INCLUDING FACILITY PLACEMENT, GRADING AND DRAINAGE WILL REQUIRE TOPOGRAPHIC SURVEY WITH TIES TO THE PROPERTY AND EASEMENTS.

20' 0 20' 40' 60' 80'
SCALE: 1" = 60'

REVISION APPROVAL RECORD				REV		REV NO	DATE	REVISIONS	BY	CHKR
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE	A	5/14/15	ISSUED FOR ENF PERMITTING	RLR	MD
ARCH.			MECHANICAL			B	5/18/15	REVISED GRADING	RLR	MD
BUILDING SERVICES			PIPING			C	6/9/15	ADDED FUEL OIL PUMPHOUSE; DELETED FUTURE ITEMS	TJK	RLR
CIVIL			PROCESS			D	10/05/15	DELETED WATER TREATMENT BUILDING, ADJUSTED AND RELOCATED INFILTRAION	RST	RLR
ELECTRICAL			QA / QC					BASIN 1, RELOCATED INFILTRATION BASIN 2		
ENVIRON.			STRUCTURAL			E	10/07/15	INCORPORATED CLIENT COMMENTS	RST	RLR
GEN. ARRANG.						F	11/18/15	INCORPORATED CLIENT COMMENTS	RST	RLR
I & C						G	11/23/15	INCORPORATED CLIENT COMMENTS	RST	RLR

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY	F	11/23/15	PKS	PKS
APPROVED FOR CONSTRUCTION				
NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED AND DATED, DESTROY ALL PRINTS BEARING EARLIER DATE AND/OR REV.NO.				

PROJECT NO.: 31380	
DRAWN: RLR	DATE: 4/23/15
CHECKED: MD	DATE: 5/14/15
SCALE: 1" = 60'-0"	

Figure 2-2
Site Plan and General Arrangement

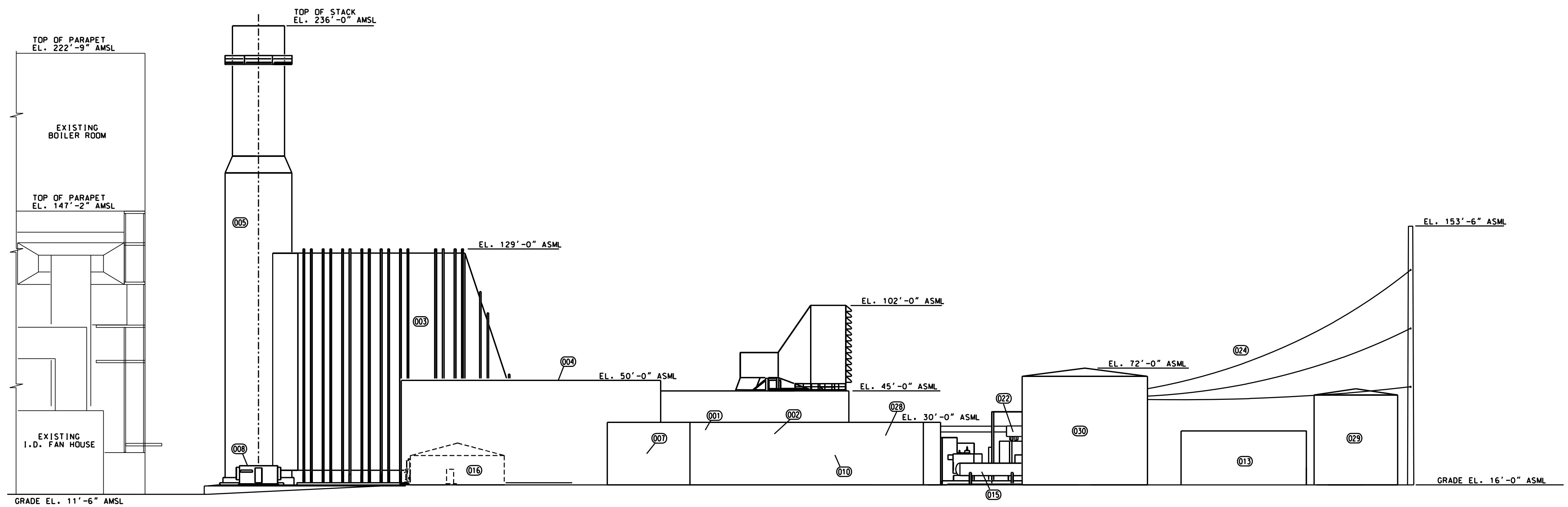
NRG Canal 3 Development LLC
Sandwich, Massachusetts

...\31380-B024-Sketch 2 Plot Plan West_RG.dgn 11/23/2015 3:16:31 PM

3 | 380-B024-WEST ELEV | 1

LEGEND

001 GAS TURBINE GE 7HA.02
002 GENERATOR
003 SCR/CO2 CATALYST
004 TEMPERING/PURGE FANS
005 STACK
007 LUBE OIL SKID
008 CEMS
010 COOLING FAN MODULE
013 DEMINERALIZED WATER SYSTEM
014 DELETED
015 HYDROGEN STORAGE AREA
016 EXISTING TRAINING BLDG. / NEW CONTROL RM.
022 GENERATOR STEP-UP TRANSFORMER (GSU)
024 TRANSMISSION LINES
028 EVAPORATOR COOLER BLOWDOWN COLLECTION TANK
029 SERVICE WATER/FIRE WATER TANK
030 DEMINERALIZED WATER TANK



ELEVATION LOOKING NORTH

10' 0 10' 20' 30'
SCALE: 1" = 20'

REVISION APPROVAL RECORD				REV		REV NO	DATE	REVISIONS	BY	CHKR
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE	A	6/10/15	ISSUED FOR REVIEW	TJK	RLR
ARCH.			MECHANICAL			B	6/16/15	CHANGED STACK ELEVATION	TJK	RLR
BUILDING SERVICES			PIPING			C	10/05/15	CHANGED STACK ELEVATION. DELETED WATER TREATMENT BUILDING	RST	RLR
CIVIL			PROCESS			D	10/07/15	INCORPORATED CLIENT COMMENTS	RST	RLR
ELECTRICAL			QA / QC			E	11/18/15	INCORPORATED CLIENT COMMENTS	RST	RLR
ENVIRON.			STRUCTURAL							
GEN. ARRANG.										
I & C										

DRAWING STATUS				
ISSUED	REV	DATE	SDE	PEM
PRELIMINARY	E	11/18/15	PKS	PKS
APPROVED FOR CONSTRUCTION				
NOT APPROVED FOR CONSTRUCTION UNLESS SIGNED AND DATED. DESTROY ALL PRINTS BEARING EARLIER DATE AND/OR REV.NO.				

PROJECT NO.: 31380
DRAWN: TJK DATE: 6/10/15
CHECKED: DATE:
SCALE: 1" = 20'-0"

Figure 2-3
Elevation View

NRG Canal 3 Development LLC
Sandwich, Massachusetts

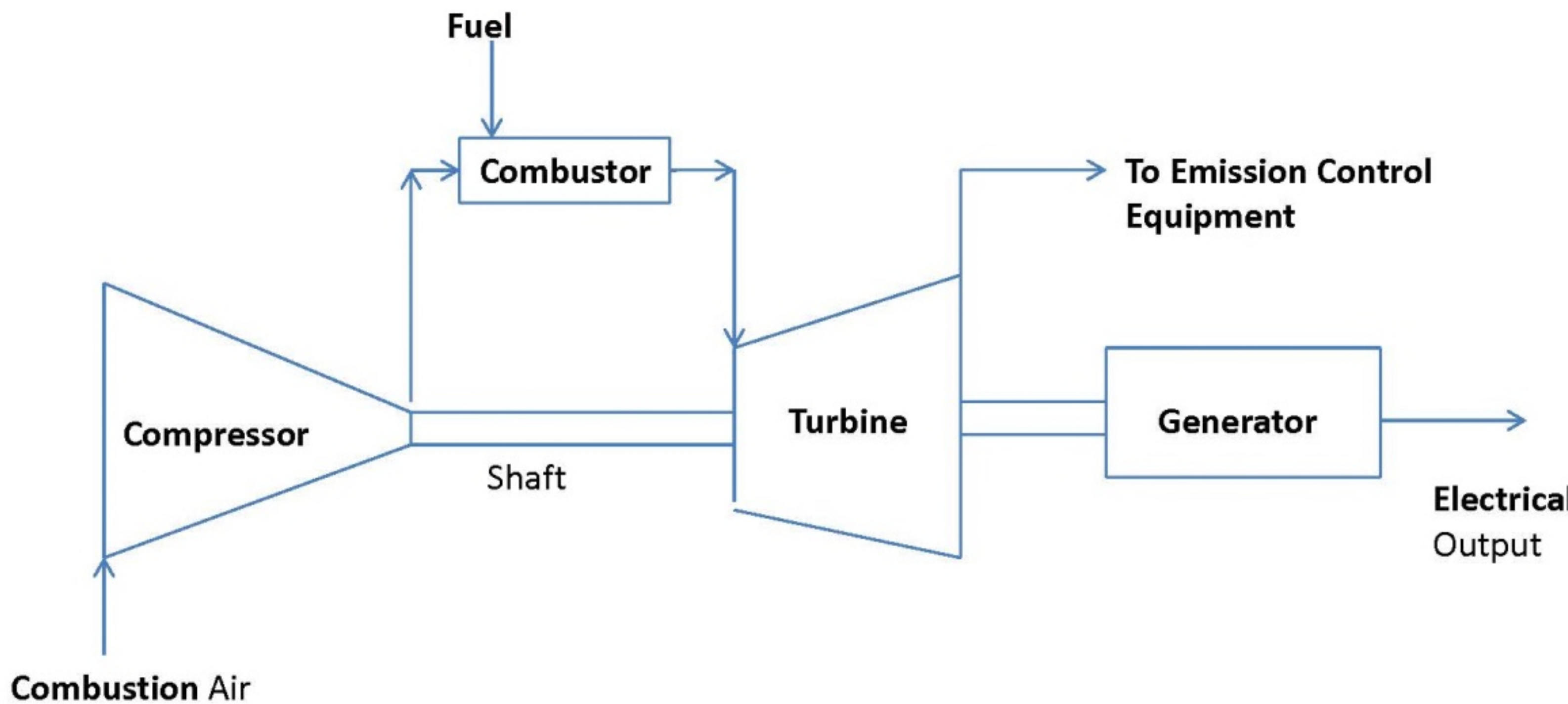


Figure 2-4
Process Flow Diagram

NRG Canal 3 Development LLC
Sandwich, Massachusetts

Locator Map

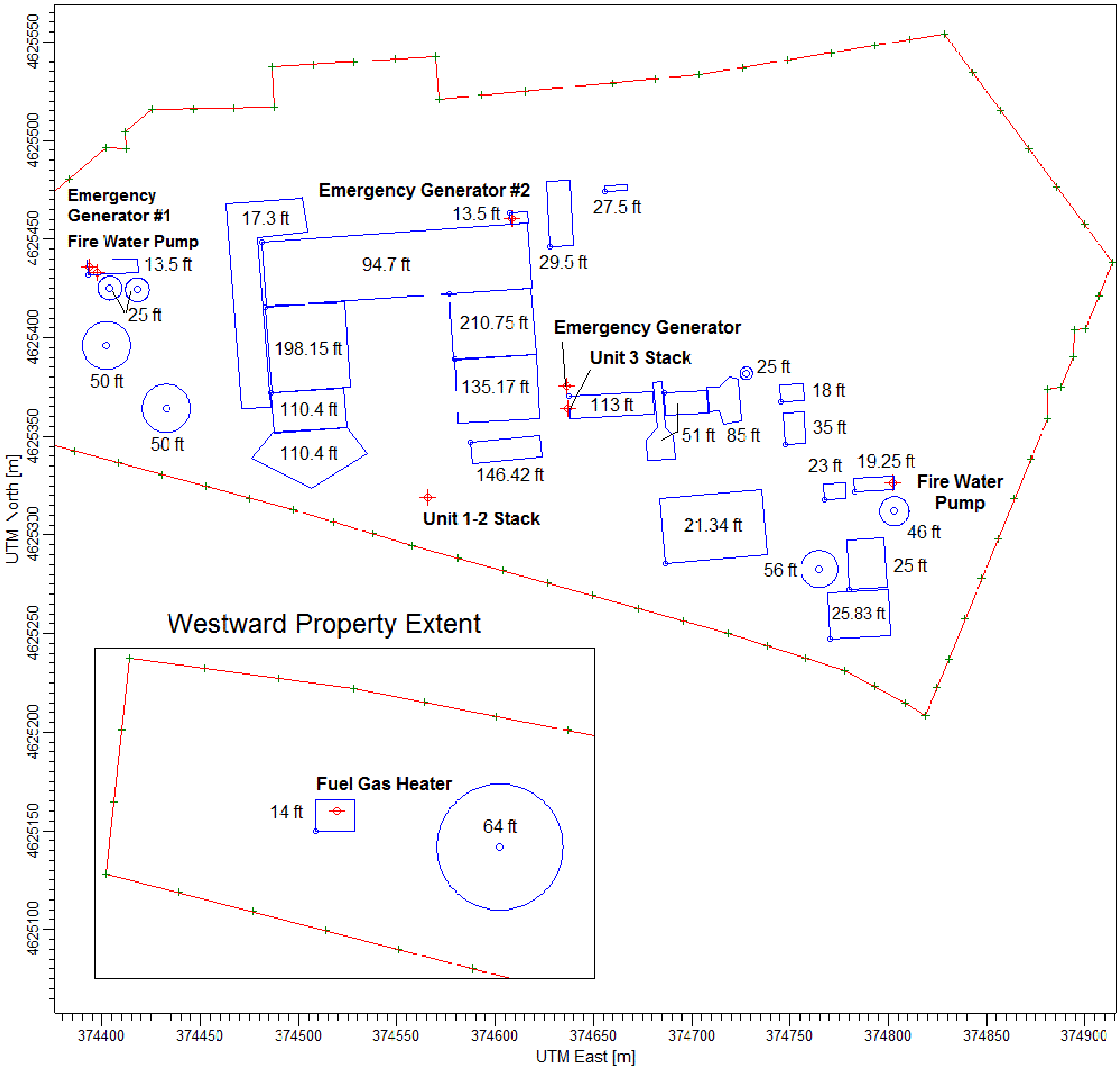
Legend

★ Canal Generating Station

Figure 6-1
Land Use Around Canal Generating Station

NRG Canal LLC
Sandwich, Massachusetts

Scale 0 0.5 1 2 Miles
0 0.75 1.5 2 Kilometers

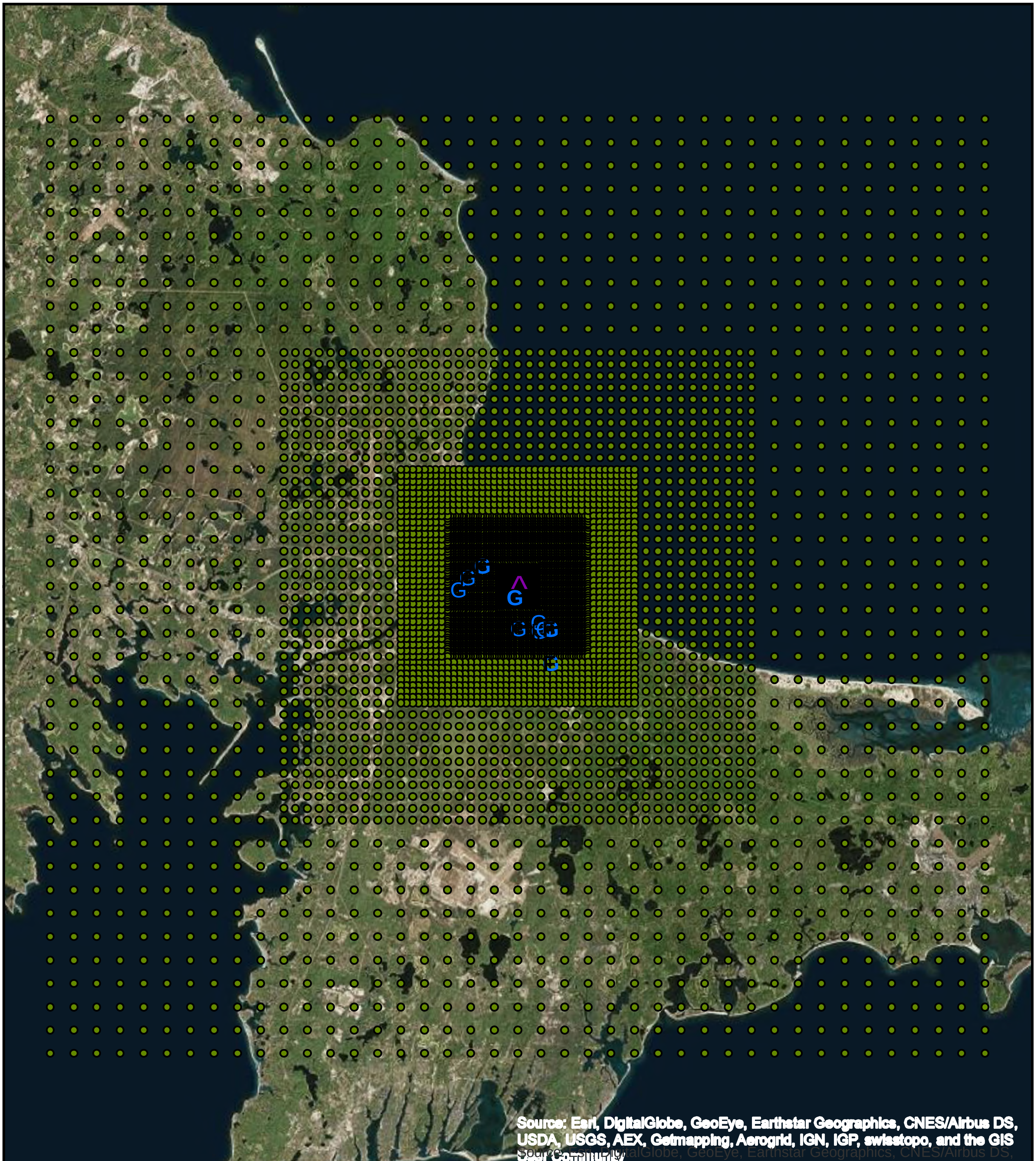


Legend

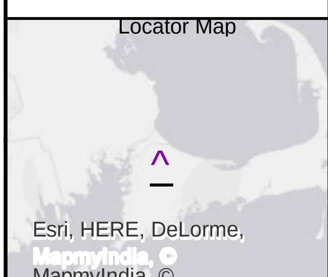
Structures/Building Footprints shown in blue
Stack locations shown in red
Facility Fence line shown in red
Fence line receptors shown in green

Figure 6-2
Structure Footprints and Heights Entered in BPIP-Prime

NRG Canal LLC
Sandwich, Massachusetts



Locator Map



Legend

Canal Generating Station

Sensitive Receptors

Cartesian Receptors

Fence Line Receptors

Fence Line

Figure 6-3
Full Receptor Grid Used for AERMOD Modeling

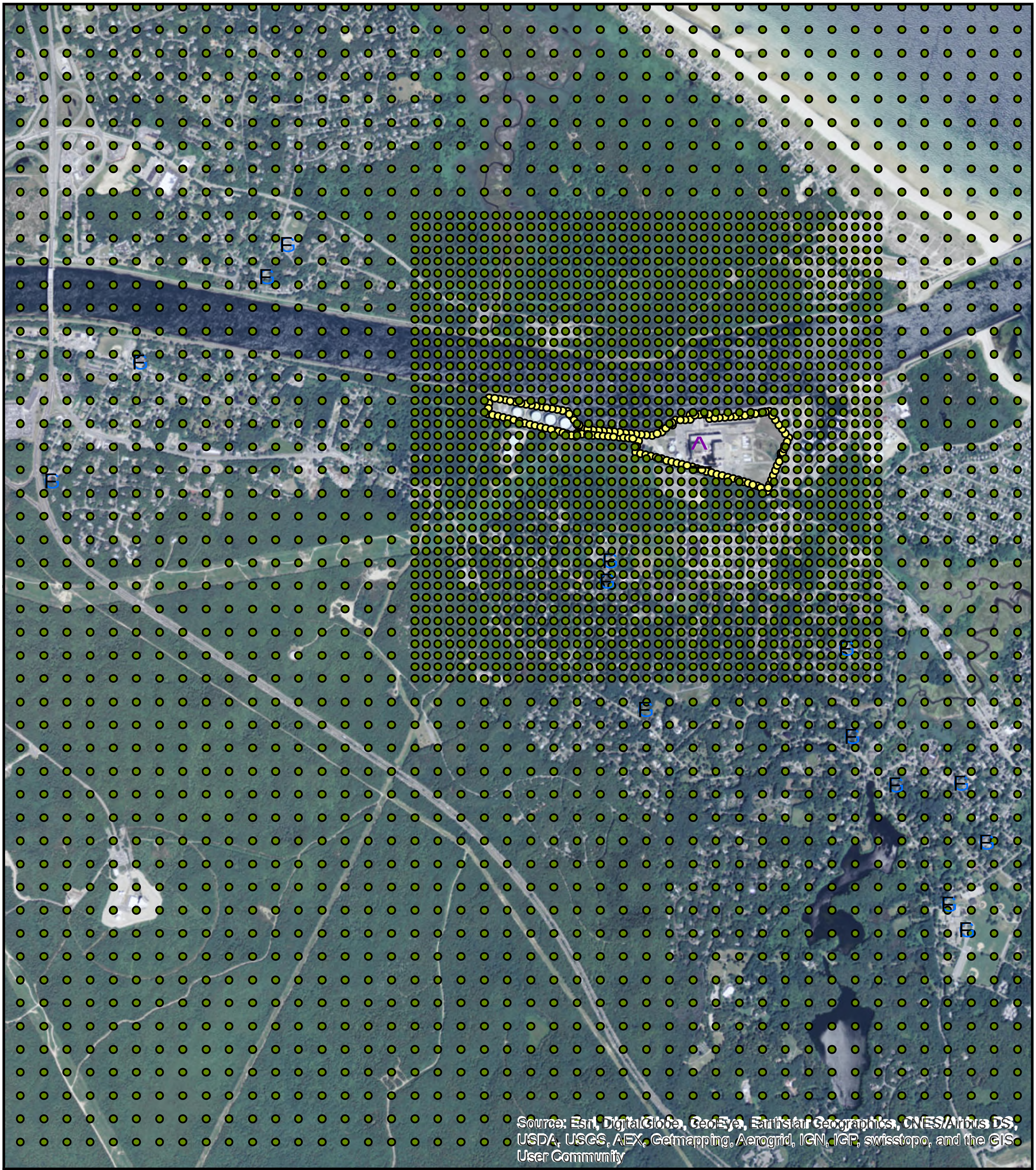
NRG Canal LLC

Sandwich, Massachusetts

Scale

0 3.75 7.5 15 Miles

0 5 10 20 Kilometers



Locator Map

Legend

- Fence Line
- Fence Line Receptors
- Cartesian Receptors
- Sensitive Receptors
- Canal Generating Station

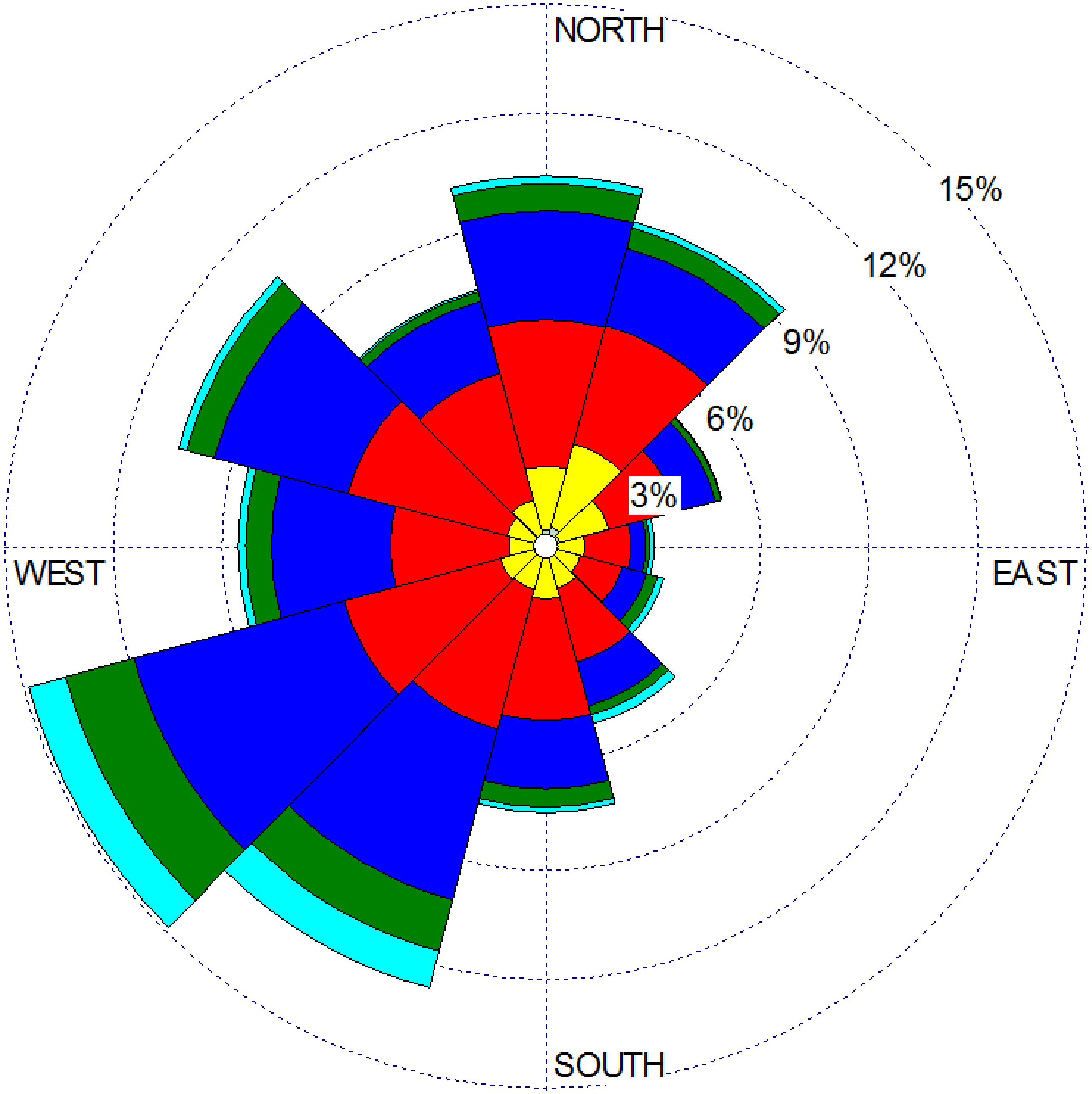
Figure 6-4
Near-Field Receptors Used in AERMOD Modeling

NRG Canal LLC
Sandwich, Massachusetts

Scale

0 | 0.375 | 0.75 | 1.5 Miles

0 | 0.5 | 1 | 2 Kilometers



WIND SPEED
(Knots)

>= 21.58
17.11 - 21.58
11.08 - 17.11
7.00 - 11.08
4.08 - 7.00
0.43 - 4.08

Calms: 0.00%

Figure 6-5
Wind Rose for Telegraph Hill Station from 2008 – 2012

NRG Canal 3 Development LLC
Sandwich, Massachusetts

Locator Map

Legend

- NO2 1-hour SIA
- PM2.5 24-hour SIA
- PM10 24-hour SIA
- Canal Generating Station

Figure 6-6
Significant Impact Areas for Short-term PM_{10}, $PM_{2.5}$, and NO_2

NRG Canal 3 Development LLC
Sandwich, Massachusetts

Scale

0 1 2 4 Miles

0 1.5 3 6 Kilometers

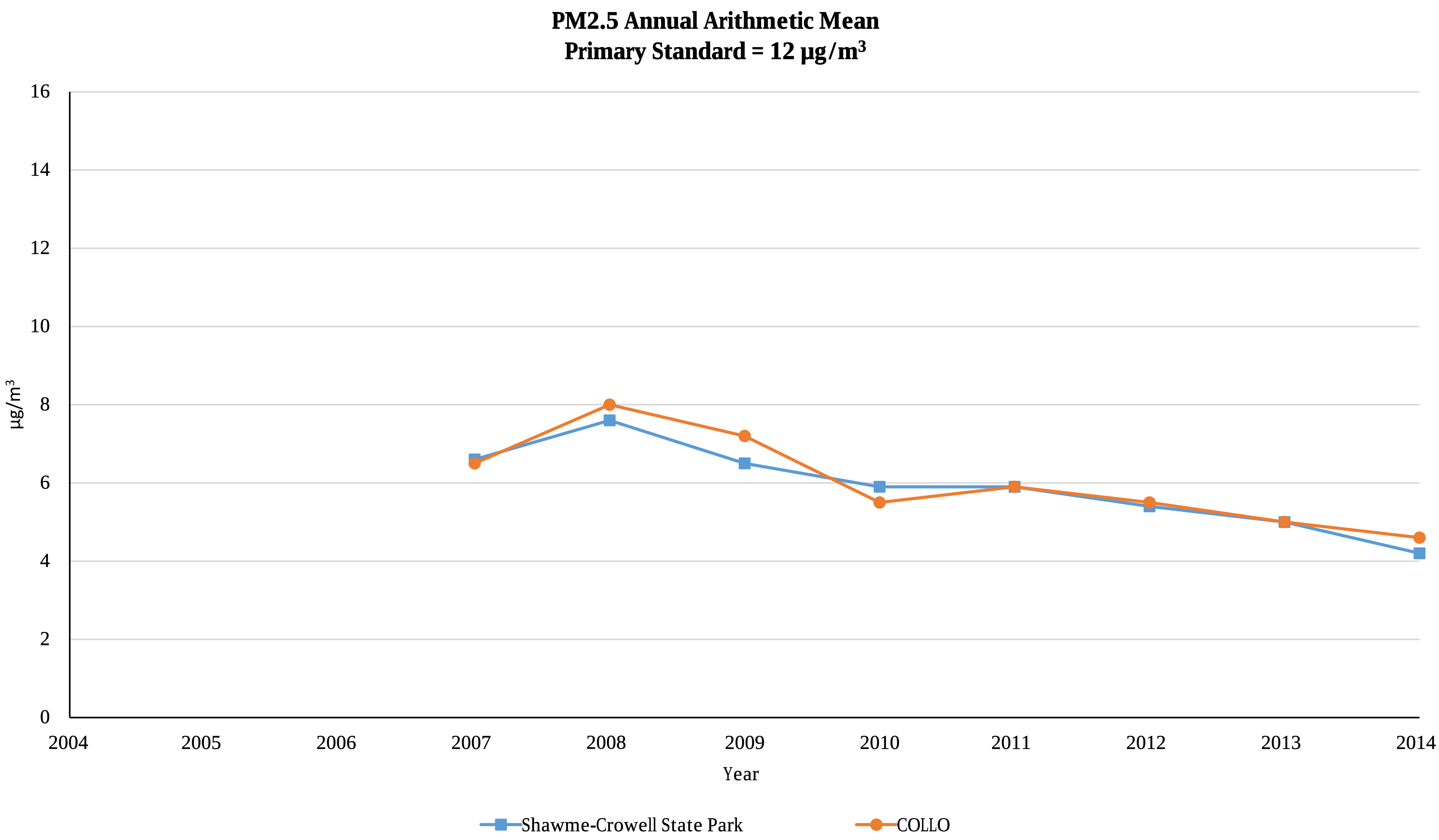


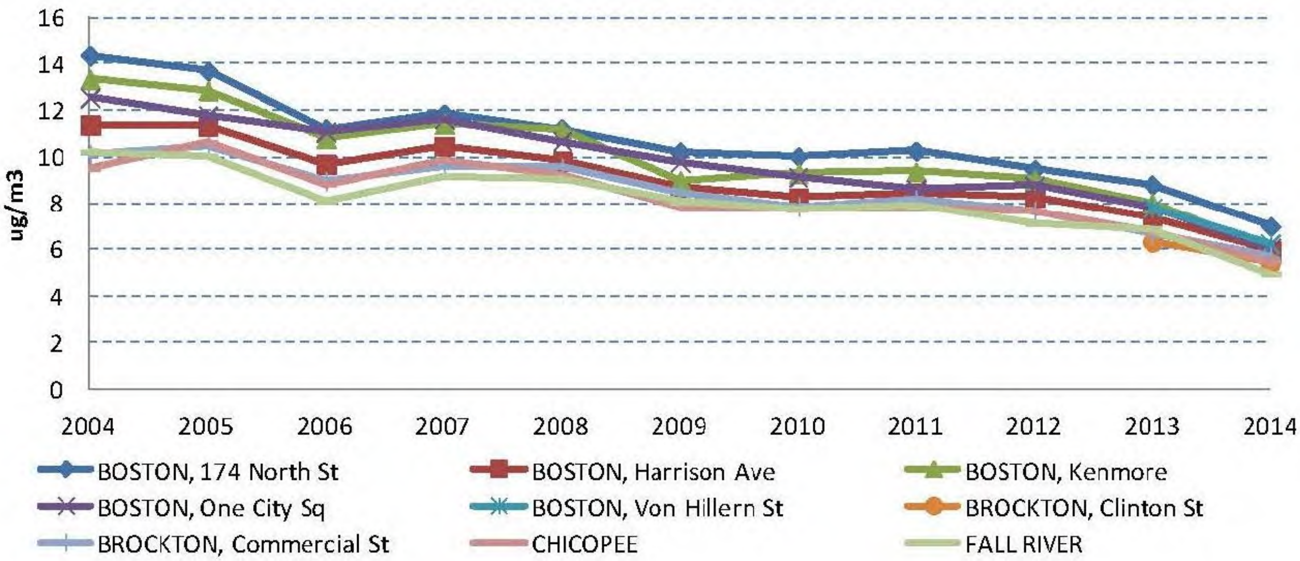
Figure 6-7
$PM_{2.5}$ Monitoring Data Trend Measured at the Shawme Crowell State Park (µg/m³)

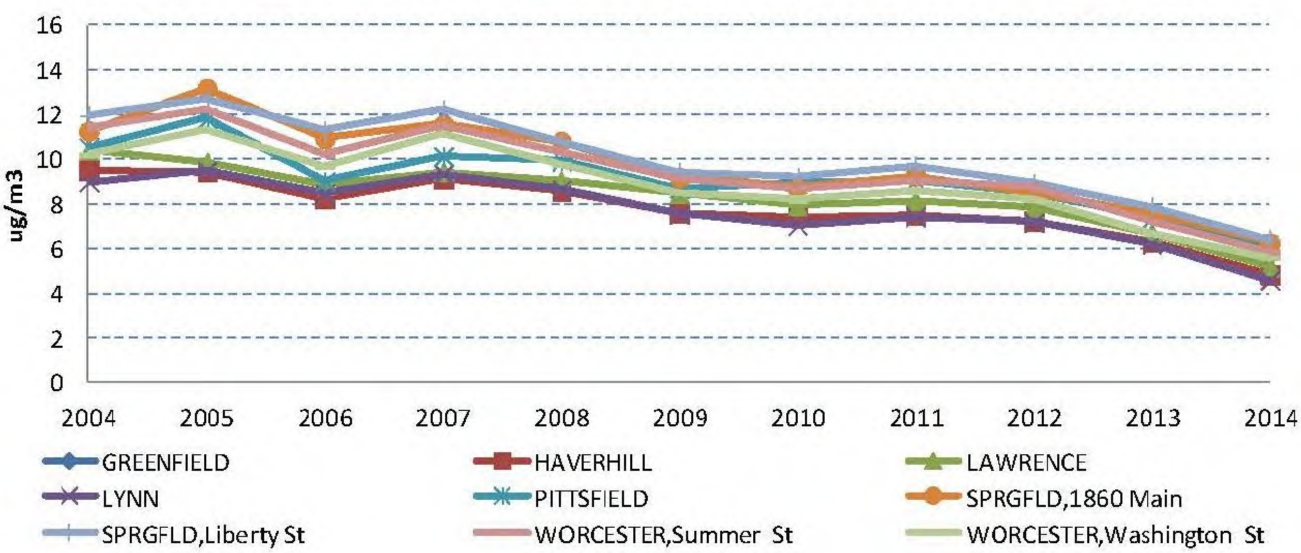
NRG Canal 3 Development LLC
Sandwich, Massachusetts

PM$_{2.5}$ FRM Trends

Long-term trends for each PM$_{2.5}$ FRM site are shown below using the annual arithmetic mean as an indicator. The data shows an overall downward trend.

Figure 8
PM$_{2.5}$ FRM Trends 2004-2014
Annual Arithmetic Mean
Primary Standard = 12 μg/m^3





(Source: Massachusetts 2014 Air Quality Report)

Figure 6-8
PM$_{2.5}$ Monitoring Data Trend in Massachusetts
(μg/m^3)

NRG Canal 3 Development LLC
Sandwich, Massachusetts

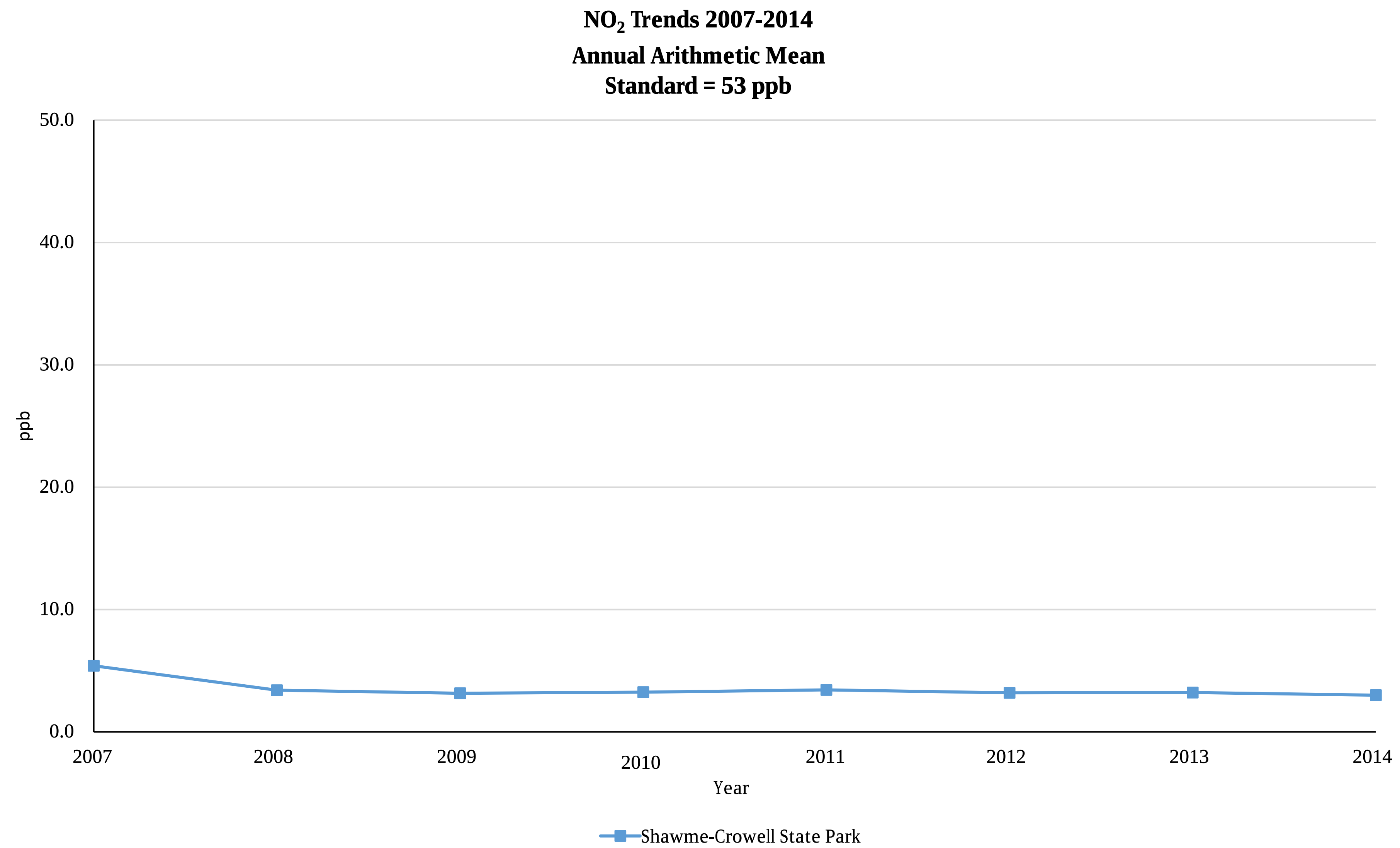
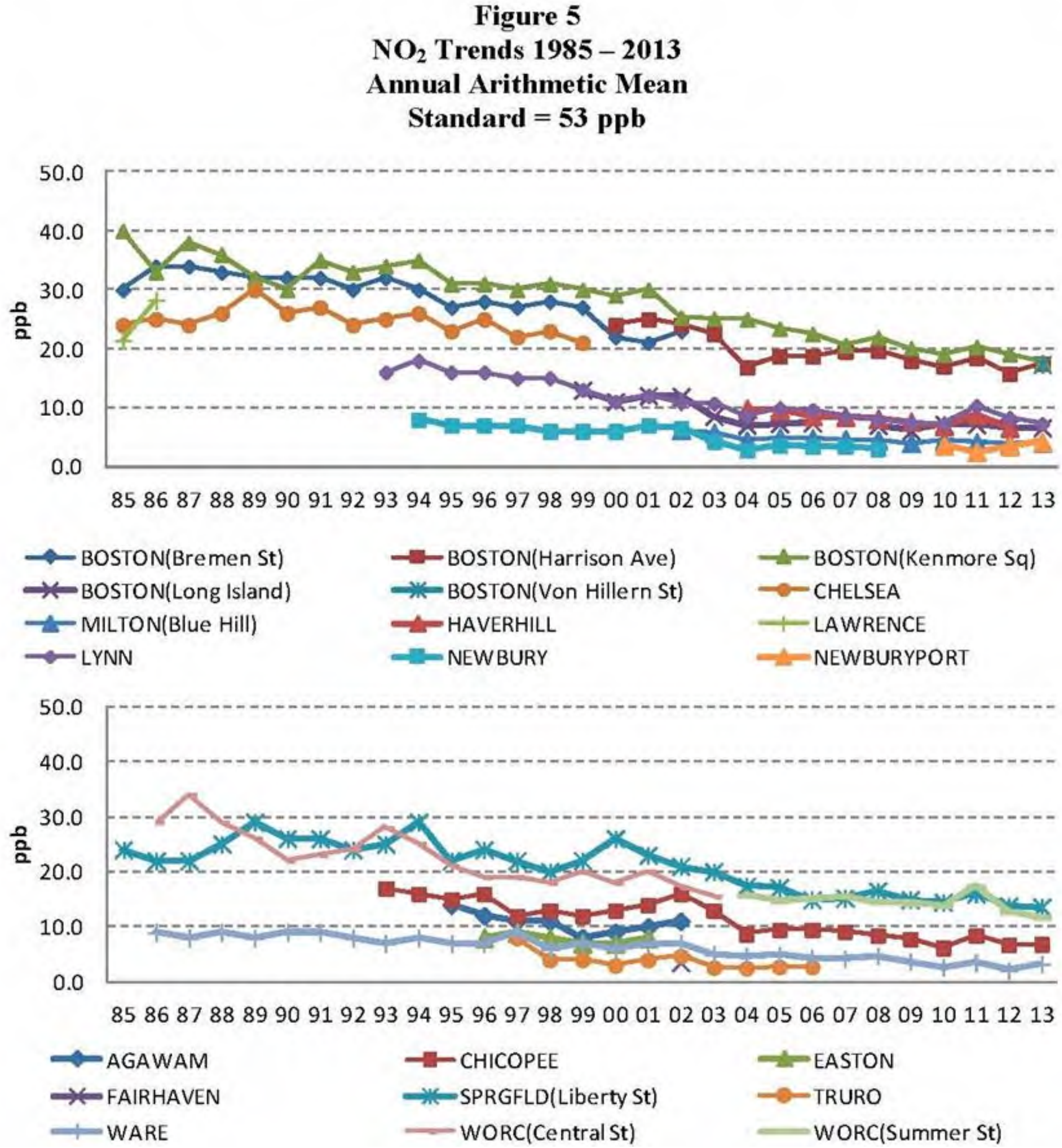


Figure 6-9
NO_2 Monitoring Data Trend Measured at the Shawme Crowell State Park (ppb)

NRG Canal 3 Development LLC
Sandwich, Massachusetts

NO_2 Trends

The long-term trends of the annual arithmetic means for each NO_2 site are shown below. The trend has been stable the last few years and downward for the entire period. Massachusetts is below the annual standard.



(Source: Massachusetts 2013 Air Quality Report)

Figure 6-10
NO_2 Monitoring Data Trend in Massachusetts (ppb)

Legend

Project Area

5-mile Buffer

EJ Criteria, by Block Group

Minority

Income

Minority and Income

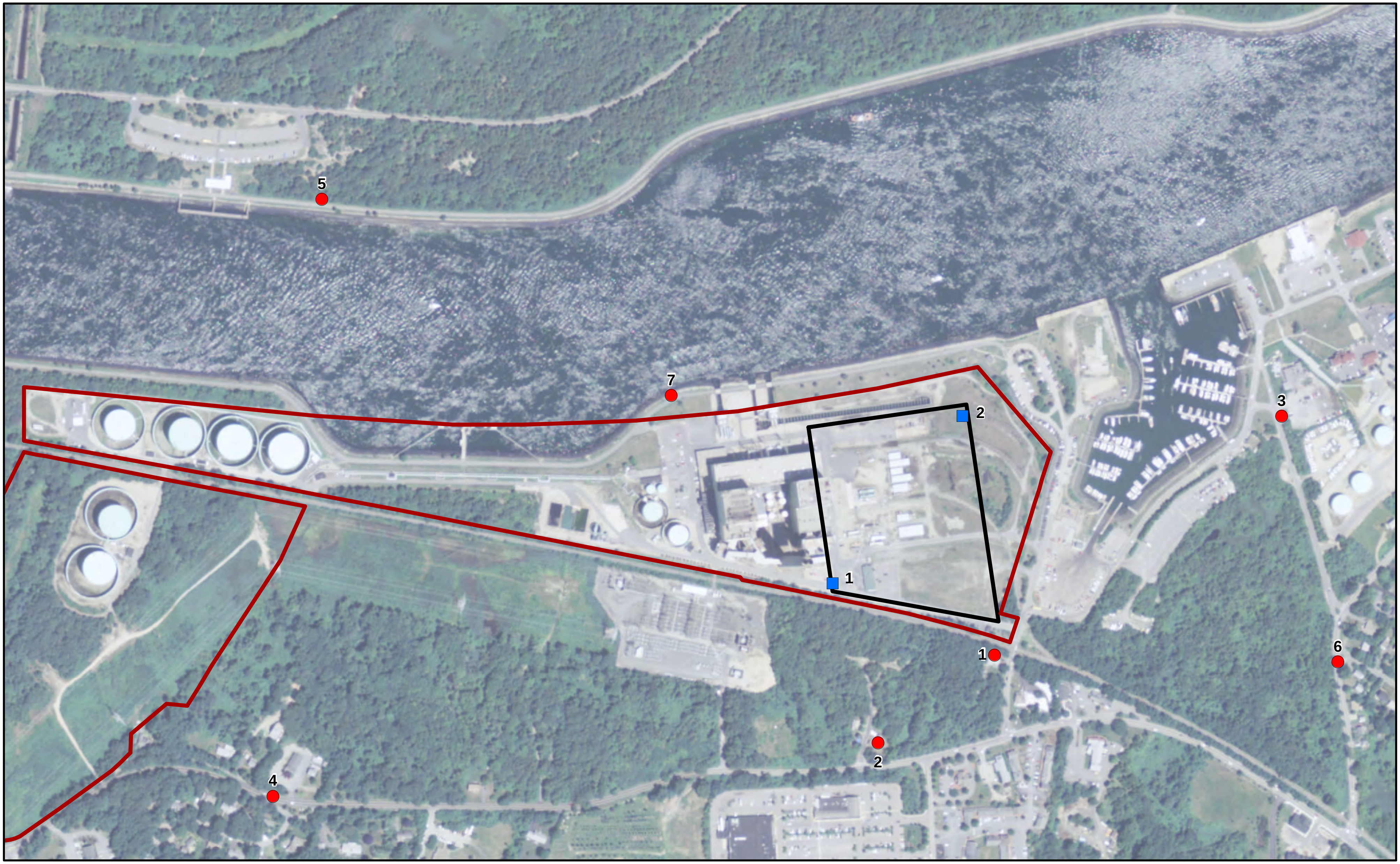
0 0.5 1 2 Miles

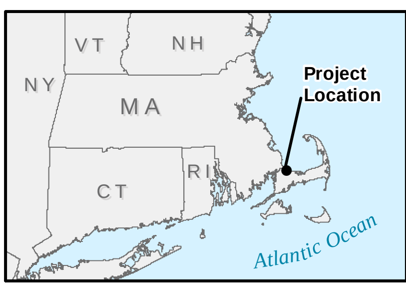
Figure 6-11

Environmental Justice Areas

Canal 3 Development LLC
Sandwich, Massachusetts

R:\Projects_2014\Canal_3\maps\Canal3_EJ_Areas.mxd





Legend

- Canal Property
- Project Site
- Short Term Monitoring Location
- Long Term Monitoring Location

N

0 250 500 Feet

Figure 7-1
Sound Level Measurement and Modeling Locations

Canal 3 Development LLC
Sandwich, Massachusetts

APPENDIX A: MASSDEP APPLICATION FORMS

Enter your transmittal number → X269143
Transmittal Number

Your unique Transmittal Number can be accessed online: http://mass.gov/dep/service/online/trasmfrm.shtml

Massachusetts Department of Environmental Protection

Transmittal Form for Permit Application and Payment

1. Please type or print. A separate Transmittal Form must be completed for each permit application.

2. Make your check payable to the Commonwealth of Massachusetts and mail it with a copy of this form to: DEP, P.O. Box 4062, Boston, MA 02211.

3. Three copies of this form will be needed.

Copy 1 - the original must accompany your permit application. **Copy 2** must accompany your fee payment. **Copy 3** should be retained for your records

4. Both fee-paying and exempt applicants must mail a copy of this transmittal form to:

MassDEP
P.O. Box 4062
Boston, MA
02211

*** Note:** For BWSC Permits, enter the LSP.

A. Permit Information

BWP AQ 03
1. Permit Code: 7 or 8 character code from permit instructions

Major CPA
2. Name of Permit Category

Simple cycle natural gas electric generating plant
3. Type of Project or Activity

B. Applicant Information – Firm or Individual

NRG Canal 3 Development LLC
1. Name of Firm - Or, if party needing this approval is an individual enter name below:

2. **Last Name** of Individual
3. **First Name** of Individual
4. MI

9 Freezer Road
5. Street Address

Sandwich	MA	02563	508-833-5363	
6. City/Town	7. State	8. Zip Code	9. Telephone #	10. Ext. #

Shawn Konary
11. Contact Person

shawn.konary@nrgenergy.com
12. e-mail address (optional)

C. Facility, Site or Individual Requiring Approval

Canal Generating Station
1. Name of Facility, Site Or Individual

9 Freezer Road
2. Street Address

Sandwich	MA	02563		
3. City/Town	4. State	5. Zip Code	6. Telephone #	7. Ext. #

120-0054		
8. DEP Facility Number (if Known)	9. Federal I.D. Number (if Known)	10. BWSC Tracking # (if Known)

D. Application Prepared by (if different from Section B)*

Tetra Tech, Inc.
1. Name of Firm Or Individual

160 Federal Street, 3rd Floor
2. Address

Boston	MA	02110	617-443-7545	
3. City/Town	4. State	5. Zip Code	6. Telephone #	7. Ext. #

George Lipka
8. Contact Person

N/A
9. LSP Number (BWSC Permits only)

E. Permit - Project Coordination

1. Is this project subject to MEPA review? ☒ yes ☐ no
If yes, enter the project's EOEA file number - assigned when an Environmental Notification Form is submitted to the MEPA unit:

15407
EOEA File Number

F. Amount Due

DEP Use Only

Permit No:

Rec'd Date:

Reviewer:

Special Provisions:

1. ☐ **Fee** Exempt (city, town or municipal housing authority)(state agency if fee is $100 or less).
There are no fee exemptions for BWSC permits, regardless of applicant status.
2. ☐ Hardship Request - payment extensions according to 310 CMR 4.04(3)(c).
3. ☐ Alternative Schedule Project (according to 310 CMR 4.05 and 4.10).
4. ☐ Homeowner (according to 310 CMR 4.02).

01036298	$24,305	02/05/2006
Check Number	Dollar Amount	Date

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

CPA-FUEL (BWP AQ 02 Non-Major, BWP AQ 03 Major)

Comprehensive Plan Application for Fuel Utilization Emission Unit(s)

X269143
Transmittal Number

120-0054
Facility ID (if known)

Use this form for:

- Boilers firing Natural Gas and having a heat input capacity of 40,000,000 British Thermal Units per hour (Btu/hr) or more.
- Boilers firing Ultra Low Sulfur Distillate Fuel Oil and having a heat input capacity of 30,000,000 Btu/hr or more.
- Emergency turbines with a rated power output of more than 1 Megawatt (MW) and/or in lieu of complying with 310 CMR 7.26(43) for engines or turbines as described at 310 CMR (43)2 and 3.
- Other Fuel Utilization Units as specified at 310 CMR 7.02(5)(a)2. See the instructions for a complete list.

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

Type of Application: ☐ BWP AQ 02 Non-Major CPA ☒ BWP AQ 03 Major CPA

A. Facility Information

Canal Generating Station
1. Facility Name

9 Freezer Road
2. Street Address

Sandwich
3. City

MA
4. State

02563
5. ZIP Code

6. MassDEP Account # / FMF Facility # (if

120-0054
7. Facility AQ # / SEIS ID # (if Known)

4911
8. Standard Industrial Classification (SIC) Code

221112 (Fossil Generation)
9. North American Industry Classification System (NAICS) Code

10. Are you proposing a new facility? ☐ Yes ☒ No - If Yes, skip to Section B.

11. List ALL existing Air Quality Plan Approvals, Emission Cap Notifications, and 310 CMR 7.26 Compliance Certifications and associated facility-wide emission caps, if any, for this facility in the table below. If you
hold a Final Operating Permit for this facility, you may leave this table blank.

Table 1

Approval Number(s)/ 25% or 50% Rule/ 310 CMR 7.26 Certification	**Transmittal Number(s)** (if Applicable)	**Air Contaminant** (e.g. CO, CO2, NOx, SO2, VOC, HAP, PM or Other [Specify])*	**Existing Facility-Wide Emission Cap(s) Per Consecutive 12-Month Time Period** (Tons)

*CO = carbon monoxide, CO_2 = carbon dioxide, NOx = nitrogen oxides, SO_2 = sulfur dioxide, VOC = volatile organic compounds,

A. Facility Information (continued)

12. Will this proposed project result in an increase in any facility-wide emission cap(s)? ☐ Yes ☒ No

    If Yes, describe:

B. Equipment Description

Note that per 310 CMR 7.02, MassDEP can issue a Plan Approval only for proposed Emission Unit(s) with air contaminant emissions that are representative of Best Available Control Technology (BACT). See Section D: Best Available Control Technology (BACT) Emissions and the MassDEP BACT Guidance.

1. Is this proposed project modifying previously approved equipment? ☐ Yes ☒ No

   If Yes, list pertinent Plan Approval(s):

2. Is this proposed project replacing previously approved equipment? ☐ Yes ☒ No

   If Yes, list pertinent Plan Approval(s):

3. Provide a description of the proposed project, including relevant parameters (including but not limited to operating temperature and pressure) and associated air pollution controls, if any:

   NRG Canal 3 Development LLC proposes to construct a new, highly efficient, fast-starting, approximately 350 MW peak electric generating unit at the existing 52-acre Canal Generating Station site on Freezer Road in Sandwich, Massachusetts. The facility is expected to operate during times of peak energy demand, for up to 4,380 hours per year and would run primarily on natural gas, with up to 720 hours per year on ultra-low sulfur distillate (ULSD) as back-up fuel. See attached cover document for detailed descriptions of

Netting & Offsets

4. Is netting being used to avoid 310 CMR 7.00: Appendix A? ☐ Yes* ☒ No

   *If Yes, attach a description of contemporaneous increases and decreases in applicable potential (or allowable) nonattainment pollutant emissions over a period of the most recent five (5) calendar years, including the year that the proposed project will commence operating. For each emission unit, this description must include: a description of the emission unit, the year it commenced operation or was removed from service, any associated MassDEP-issued Plan Approval(s), and its potential (or allowable) nonattainment pollutant emissions. In any case, a proposed project cannot "net out" of the requirement to submit a plan application and comply with Best Available Control Technology (BACT) pursuant to 310 CMR 7.02.

5. Is the proposed project subject to 310 CMR 7.00: Appendix A Nonattainment Review? ☒ Yes* ☐ No – Skip to 6

   *If Yes, pursuant to 310 CMR 7.00: Appendix A(6), federally enforceable emission offsets, such as Emission Reduction Credits (ERCs), must be used for this part of the application. Complete Table 2 on the next page to summarize either the facility providing the federally enforceable emission offsets, or what is being shut down, curtailed or further controlled at this facility to obtain the required emission offsets. Emission offsets must be part of a federally enforceable Plan Approval to be used for offsetting emission increases in applicable nonattainment pollutants or their precursors.

B. Equipment Description (continued)

Note: Complete this table if you answered Yes to Question 5. Otherwise, skip to Question 6.

Table 2

Source of Emission Reduction Credits (ERCs) or Emission Offsets	**Transmittal No. of Plan Approval Verifying Generation of ERCs, if Any**	**Air Contaminant**	**Actual Baselines Emissions** (Tons per Consecutive 12-Month Time Period)[1]	**New Potential Emissions[2]** (Tons per Consecutive 12-Month Time Period After Control)	**ERC[3] or Emission Offsets, Including Offset Ratio & Required ERC Set Aside** (Tons per Consecutive 12-Month Time Period)
Lovett Station	NYSDEC #3-3928-00010	NOx	4209.2	0	4209.2

[1] Actual Baseline Emissions means the average actual emissions for the source of emission credits or offsets in the previous two years (310 CMR 7.00: Appendix A).
[2] New Potential Emissions means the potential emissions for the source of emission credits or offsets after project completion (310 CMR 7.00: Appendix A).
[3] Emission Reduction Credit (ERC) means the difference between Actual Baseline and New Potential Emissions, including an offset ratio of 1.26:1 (310 CMR 7.00: Appendix B(3)).

6. Complete the table below to summarize the details of the proposed project.

Note: For additional information, see the instructions for a link to the MassDEP BACT Guidance.

Table 3

Facility-Assigned Identifying Number for Proposed Equipment (Emission Unit No.)	**Description of Proposed Equipment Including Manufacturer & Model Number or Equivalent** (e.g. Acme Boiler, Model No. AB500)	**Manufacturer's Maximum Heat Input Rating in Btu/hr**	**Proposed Primary Fuel**	**Proposed Back-Up Fuel** (if Any)
EU-10 ☒ New ☐ Modified	GE 7HA.02 Combustion Turbine Generator (CTG) or comparable unit	3,471,000,000 (0º F ULSD firing)	Natural Gas	Ultra Low-Sulfur Diesel (ULSD)
EU-11 ☒ New ☐ Modified	Caterpillar Tier 4 Alternate FEL C-15 ATAAC Diesel Emergency Generator or similar unit	5,030,000	ULSD	None
EU-12 ☒ New ☐ Modified	Jon Deere/Clarke JU4H-UFAD5G Emergency Diesel Fire Pump or similar unit	1,200,000	ULSD	None

B. Equipment Description (continued)

7. Complete the table below to summarize the burner details if the proposed project includes boiler(s).

Note: For additional information, see the instructions for a link to the MassDEP BACT Guidance.

Table 4

Emission Unit No.	**Burner Manufacturer & Model Number or Equivalent** (e.g. Acme Burner, Model No. AB300)	**Manufacturer's Maximum Firing Rate** (Gallons per Hour or Cubic Feet per Hour)	**Type of Burner** (e.g. Ultra Low NOx Burner)	**Is Emission Unit Equipped with Flue Gas Recirculation?**
N/A				☐ Yes ☐ No
				☐ Yes ☐ No
				☐ Yes ☐ No
				☐ Yes ☐ No

8. Complete the table below if the proposed project includes turbine(s).

Table 5

Emission Unit No.	**Maximum Firing Rate** (Gallons per Hour or Cubic Feet per Hour)	**Maximum Output Rating** (Megawatts [MW] or Kilowatts [kW]; Indicate Unit of Measure)
EU-10 (CTG)	3,425,000 million scf/hr (gas at 1000 Btu HHV/scf) 24,793 gal/hr (ULSD at 140,000 Btu HHV/gal) (both at 0º F)	364.391 MW (estimated maximum gross output at **0º F)**

Continue to Next Page ►

B. Equipment Description (continued)

9. Are you proposing an Air Pollution Control Device (PCD)? ☒ Yes* ☐ No

*If Yes, complete the table below to summarize the details of each PCD being proposed.

Note: If you are proposing one or more Air Pollution Control Devices (PCDs), you must also submit the applicable Supplemental Form(s). See Page 6 for additional information.

Table 6a

Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
SCR ☒ New ☐ Existing	EU-10 (CTG)	VOC	
		CO	
		PM[1]	
		NO_x	90%
		NH_3	

[1] PM includes particulate matter having a diameter of 10 microns or less (PM_{10}) and particulate matter having a diameter of 2.5 microns or less ($PM_{2.5}$).

Note: If you are proposing more than two Air Pollution Control Devices (PCDs), complete additional copies of these tables.

Table 6b

Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
Oxidation Catalyst ☒ New ☐ Existing	EU-10 (CTG)	VOC	25%
		CO	75%
		PM[1]	
		NO_x	
		NH_3	
		Other:	

B. Equipment Description (continued)

Supplemental Forms Required

If you are proposing one or more PCDs, you will also need to submit the applicable form(s) below.

If Your Project Includes:	You Must File Form(s):
Wet or Dry Scrubbers	BWP AQ Scrubber
Cyclone or Inertial Separators	BWP AQ Cyclone
Fabric Filter	BWP AQ Baghouse/Filter
Adsorbers	BWP AQ Adsorption Equipment
Afterburners or Oxidizers	BWP AQ Afterburner/Oxidizer
Electrostatic Precipitators	BWP AQ Electrostatic Precipitator
Selective Catalytic Reduction	BWP AQ Selective Catalytic Reduction
Sorbent/Reactant Injection	BWP AQ Sorbent/Reactant Injection

10. Is there any external noise generating equipment associated with the proposed project? ☒ Yes ☐ No – Skip to 12

11. Complete the table(s) below to summarize all associated noise suppression equipment, if any is being proposed, and attach a completed Form BWP AQ Sound to this application (unless MassDEP waives this requirement).

Note: The installation of some fuel burning equipment can cause off-site noise if proper precautions are not taken. For additional guidance, see MassDEP's Noise Pollution Policy Interpretation.

Table 7

Emission Unit No.	Type of Noise Suppression Equipment (e.g. Mufflers, Acoustical Enclosures)	Equipment Manufacturer	Equipment Model No.
EU-10	See Application Text	TBD	TBD

B. Equipment Description (continued)

12. Have you attached a completed Form BWP AQ Sound to this application? ☒ Yes ☐ No*

*If No, explain:

13. Describe the potential for visible emissions from the proposed project and how they will be controlled:

The potential for visible emissions will be negligible due to the use of natural gas and ultra-low sulfur diesel oil as the only fuels. Visible emissions will be controlled through good combustion practices.

14. Describe the potential for odor impacts from the proposed project and how they will be controlled:

The proposed project has no potential for odor impacts.

C. Stack Description

Complete the table below to summarize the details of the proposed project's stack configuration.

Note: Discharge must meet Good Air Pollution Control Engineering Practice. When designing stacks, special consideration must be given to nearby structures and terrain to prevent emissions downwash and adverse impacts upon sensitive receptors. Stack must be vertical, must not impede vertical exhaust gas flow, and must be a minimum of 10 feet above rooftop or fresh air intake, whichever is higher. For additional guidance, refer to the MassDEP "Stack Design General Guidelines." See the instructions for a link.

Table 8

Emission Unit No.	**Stack Height Above Ground** (Feet)	**Stack Height Above Roof** (Feet)	**Stack Exit Diameter or Dimensions** (Feet)	**Exhaust Gas Exit Temperature Range** (Degrees Fahrenheit)	**Exhaust Gas Exit Velocity Range** (Feet per Second)	**Stack Liner Material**
1	220	107	25	750	75.1 – 135.9	Steel
2	25	-88	0.75	887.1	139.3	Steel
3	25	5.75	0.33	809.0	127.0	Steel

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D. Best Available Control Technology (BACT) Emissions

1. Complete the table(s) below to summarize the proposed project's BACT emissions.

Note: Complete a separate table for each proposed fuel to be used in each Emission Unit. For example, if one Emission Unit will be capable of burning two different fuels, you will need to complete two tables.

Table 9A

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5] **(ton per year CTG total both fuels)**	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. EU-10 (CTG) Fuel Used Natural Gas	PM[1]	18.1 lb/hr	***>=75% load, 18.1 lb/hr, not to exceed 0.0073 lb/MMBtu <75% load, 18.1 lb/hr, not to exceed 0.012 lb/MMBtu***	60.4	N/A	N/A
	$PM_{2.5}$	18.1 lb/hr		60.4	N/A	N/A
	PM_{10}	18.1 lb/hr		60.4	N/A	N/A
	NO_x[2]	25 ppmvd @ 15% O2	2.5 ppmvdc	103.5	N/A	N/A
	CO	9 ppmvd @ 15% O2	***3.5*** ppmvdc	***94.0***	N/A	N/A
	VOC	1.4 ppmvw GE estimate (2.0 ppmvdc is guarantee)	2.0 ppmvdc	23.3	N/A	N/A
	SO_2	0.0015 lb/MMBtu	0.0015 lb/MMBtu	11.1	N/A	N/A
	Formaldehyde	0.00022 lb/MMBtu	0.00022 lb/MMBtu	1.6	N/A	N/A
	Total HAPs[3]	0.00054 lb/MMBtu	0.00054 lb/MMBtu	3.9	N/A	N/A
	NH_3	N/A	5 ppmvdc; optimization goal 2.0 ppmvdc	50.3	N/A	N/A
	CO_2[4]	1,178 lb/MW gross at ISO full load	1,178 lb/MW gross at ISO full load	932,325	N/A	N/A

ppmvdc = parts per million @ 15% O_2 dry basis; ppmw = parts per million wet basis

[1]PM includes particulate matter having a diameter of 10 microns or less (PM_{10}) and particulate matter having a diameter of 2.5 microns or less ($PM_{2.5}$).
[2] NO_x emissions from this proposed project need to be included for the purposes of NO_x emissions tracking for 310 CMR 7.00: Appendix A, if applicable.
[3]Operating Permit facilities are required to track emissions of Hazardous Air Pollutants.
[4]Pounds of CO_2 per unit product (e.g. pounds CO_2 per megawatt, pounds CO_2 per 1,000 pounds of steam).
[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.

D. Best Available Control Technology (BACT) Emissions

1. Complete the table(s) below to summarize the proposed project's BACT emissions.

Note: Complete a separate table for each proposed fuel to be used in each Emission Unit. For example, if one Emission Unit will be capable of burning two different fuels, you will need to complete two tables.

Table 9A

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5] **(ton per year CTG total both fuels)**	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. EU-10 (CTG) Fuel Used Natural Gas	PM[1]	***65.8*** lb/hr	***>=75% load, 65.8 lb/hr, not to exceed 0.026 lb/MMBtu; <75% load, 65.8 lb/hr, not to exceed 0.046 lb/MMBtu***	**60.4**	N/A	N/A
	$PM_{2.5}$	***65.8*** lb/hr		**60.4**	N/A	N/A
	PM_{10}	***65.8*** lb/hr		**60.4**	N/A	N/A
	NO_x[2]	42 ppmvd @ 15% O2	5.0 ppmvdc	103.5	N/A	N/A
	CO	20 ppmvd @ 15% O2	5.0 ppmvdc	***94.0***	N/A	N/A
	VOC	3.5 ppmvw	2.0 ppmvdc	23.3	N/A	N/A
	SO_2	0.0015 lb/MMBtu	0.0015 lb/MMBtu	11.1	N/A	N/A
	Formaldehyde	0.00023 lb/MMBtu	0.00023 lb/MMBtu	1.6	N/A	N/A
	Total HAPs[3]	0.00039 lb/MMBtu	0.00039 lb/MMBtu	3.9	N/A	N/A
	NH_3	N/A	5 ppmvdc	50.3	N/A	N/A
	CO_2[4]	1,673 lb/MW gross at ISO full load	1,673 lb/MW gross at ISO full load	932,325	N/A	N/A

ppmvdc = parts per million @ 15% O_2 dry basis; ppmw = parts per million wet basis

[1]PM includes particulate matter having a diameter of 10 microns or less (PM_{10}) and particulate matter having a diameter of 2.5 microns or less ($PM_{2.5}$).
[2] NO_X emissions from this proposed project need to be included for the purposes of NO_X emissions tracking for 310 CMR 7.00: Appendix A, if applicable.
[3]Operating Permit facilities are required to track emissions of Hazardous Air Pollutants.
[4]Pounds of CO_2 per unit product (e.g. pounds CO_2 per megawatt, pounds CO_2 per 1,000 pounds of steam).
[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.

D. Best Available Control Technology (BACT) Emissions (continued)

Table 9B

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. EU-11 (Canal 3 emergency generator engine) Fuel Used ULSD	PM	0.1 grams/kWhr	0.1 grams/kWhr*	0.03		
	$PM_{2.5}$	0.1 grams/kWhr	0.1 grams/kWhr*	0.03		
	PM_{10}	0.1 grams/kWhr	0.1 grams/kWhr*	0.03		
	NOx	3.5 grams/kWhr	3.5 grams/kWhr*	0.67		
	CO	3.5 grams/kWhr	3.5 grams/kWhr*	0.67		
	VOC	0.19 grams/kWhr	0.19 grams/kWhr*	0.04		
	SO_2	0.0015 lb/MMBtu	0.0015 lb/MMBtu	0.0011		
	HAP					
	Total HAPs					
	CO_2	162.85 lb/MMBtu	162.85 lb/MMBtu	123		

*Particulate, NOx, CO and VOC proposed BACT limits are based on grams/kilowatt-hour as determined by 40 CFR 60 Subpart IIII test procedure and 40 CFR 1039.101 Table 1 and 1039.104(g) Table 1.

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D. Best Available Control Technology (BACT) Emissions (continued)

Note: If you are proposing more additional Emissions Units or fuels, complete additional copies of these tables.

Table 9C

Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. EU-12 (Canal 3 fire pump engine) Fuel Used ULSD	PM	0.3 grams/kWhr	0.3 grams/kWhr*	0.01		
	$PM_{2.5}$	0.3 grams/kWhr	0.3 grams/kWhr*	0.01		
	PM_{10}	0.3 grams/kWhr	0.3 grams/kWhr*	0.01		
	NO_x	4.0 grams/kWhr	4.0 grams/kWhr*	0.13		
	CO	5.0 grams/kWhr	5.0 grams/kWhr*	0.17		
	VOC	1.3 grams/kWhr	1.3 grams/kWhr*	0.04		
	SO_2	0.0015 lb/MMBtu	0.0015 lb/MMBtu	0.0003		
	HAP					
	Total HAPs					
	CO_2	162.85 lb/MMBtu	162.85 lb/MMBtu	29		

*Particulate, NOx, CO and VOC proposed BACT limits are based on grams/kilowatt-hour as determined by 40 CFR 60 Subpart IIII test procedure and methods for a Tier 3 fire pump engine. Since the NOx + VOC limit is 4.0 grams/kWhr, the VOC limit alone is based on the Tier 1 VOC limit of 1.3 grams/kWhr.

Note: Top-Case BACT is the emission rate identified via the MassDEP BACT Guidance or a pre-application meeting with MassDEP.

2. Are proposed BACT emission limits in the tables above Top-Case BACT as referenced in 310 CMR 7.02(8)(a)2.a? ☐ Yes ☒ No*

*If No, you must submit form BWP AQ BACT to demonstrate that this project meets BACT as provided in 310 CMR 7.02(8)(a)2 or 310 CMR 7.02(8)(a)2.c.. **BWP AQ BACT is presented for EU-11 and EU-12 for SCR, CO catalyst and DPF.**

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E. Monitoring Procedures

Complete the table below to summarize the details of the proposed project's monitoring procedures.

Table 10

Emission Unit No.	Type or Method of Monitoring (e.g. CEMS[1], Fuel Flow)	Parameter/Emission Monitored	Frequency of Monitoring
EU-10 (CTG)	CEMS, Fuel Flow,	NOx, CO, NH3, opacity, fuel flow	Continuous
EU-11	Hour meter	Hours of operation	Continuous
EU-12	Hour meter	Hours of operation	Continuous

[1] CEMS = Continuous Emissions Monitoring System

F. Record Keeping Procedures

Complete the table below to summarize the details of the proposed project's record keeping procedures. Proposed record keeping procedures need to be able to demonstrate your compliance status with regard to all limitations/restrictions proposed herein. Record keeping may include, but is not limited to, hourly or daily logs, meter charts, time logs, fuel purchase receipts, CEMS records, etc.

Table 11

Emission Unit No.	Parameter/Emission (e.g. Temperature, Material Usage, Air Contaminant)	Record Keeping Procedures (e.g. Data Logger or Manual)	Frequency of Data Record (e.g. Hourly, Daily)
EU-10 (CTG)	CEMS, Fuel Flow, SCR parameters	CEMS	Consistent with 40 CFR Parts 60 and 75
EU-11	Hour meter	Hours of operation	Daily
EU-12	Hour meter	Hours of operation	Daily

Examples of emissions calculations for record keeping purposes:

NOx: {(0.085 pounds per 1,000,000 British thermal units (MMBtu)*(**X** cubic feet)*(1,000 Btu per cubic feet) + (0.10 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon)}* 1 ton per 2000 pounds = NOx in tons per consecutive twelve month time period

CO: {(0.035 pounds per MMBtu)*(**X** cubic feet)*(1000 Btu per cubic feet) + (0.035 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon}*1 ton per 2000 pounds = CO in tons per consecutive twelve month time period

VOC: {(0.035 pounds per MMBtu)*(**X** cubic feet)*(1000 Btu per cubic feet) + (0.035 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon}*1 ton per 2000 pounds= VOC in tons per consecutive twelve month time period

SO_2: {(0.0015 lb per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon)}*1 ton per 2000 pounds = SO_2 in tons per consecutive twelve month time period

Where: **X** = cubic feet of natural gas burned per consecutive twelve month time period
Y = gallons of ULSD oil burned per consecutive twelve month time period

G. Additional Information Checklist

Attach a specific facility description and the following required additional information that MassDEP needs to process your application. Check the box next to each item to ensure that your application is complete.

☒ Plot Plan

☒ Combustion Equipment Manufacturer Specifications, Including but not Limited to Emissions Data

☐ Combustion Equipment Standard Operating Procedures **Will be provided when available**

☐ Combustion Equipment Standard Maintenance Procedures, Including Cleaning Method & Frequency **Will be provided when available**

☒ Calculations to Support This Plan Application

☐ Air pollution control device manufacturer specifications, if applicable **Will be provided when available**

☐ Air pollution control device standard operating procedures, if applicable **Will be provided when available**

☐ Air pollution control device standard maintenance procedures, if applicable **Will be provided when available**

☒ BWP AQ BACT Form, if not proposing Top-Case BACT

☒ Air quality dispersion modeling demonstration documenting that National Ambient Air Quality Standards (NAAQS) are not exceeded

☒ Process flow diagram for the proposed equipment and any PCD, if applicable, including relevant parameters (e.g. flow rate, pressure and temperature)

Note: Pursuant to 310 CMR 7.02(5)(c), MassDEP may request additional information.

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H. Other Regulatory Considerations

Indicate below whether the proposed project is subject to any additional regulatory requirements.

310 CMR 7.00: Appendix A Nonattainment Review, or is netting used to avoid review under 310 CMR 7.00 Appendix A or 40 CFR 52.21? ☒ Yes ☐ No

40 CFR 60: New Source Performance Standards (NSPS)? ☒ Yes ☐ No

If Yes: Which subpart? **See text** Applicable emission limitation(s): **See text**

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAPS) ☐ Yes ☒ No

If Yes: Which subpart? Applicable emission limitation(s):

40 CFR 63: NESHAPS for Source Categories – Maximum Achievable (MACT) or Generally Available (GACT) Control Technology ☒ Yes ☐ No

If Yes: Which subpart? **ZZZZ** Applicable emission limitation(s): **NSPS IIII**

301 CMR 11.00: Massachusetts Environmental Policy Act (MEPA)? ☒ Yes ☐ No

If Yes: EOEA No.: **15407**

Other Applicable Requirements? ☒ **Yes** ☐ **No**

If Yes: Specify: **EFSB 15-06**

Facility-Wide Potential-to-Emit Hazardous Air Pollutants (HAPS): ☒ Major* ☐ Non-Major

*A Major source has a facility-wide potential-to-emit of 25 tons per year or more of the sum of all hazardous air pollutants or 10 tons per year or more of any individual hazardous air pollutant.

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Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

CPA-FUEL (BWP AQ 02 Non-Major, BWP AQ 03 Major)

Comprehensive Plan Application for Fuel Utilization Emission Unit(s)

X269143
Transmittal Number

120-0054
Facility ID (if known)

I. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

George S. Lipka
P.E. Name (Type or Print)

George S. Lipka
P.E. Signature

Consulting Engineer
Position/Title

Tetra Tech, Inc.
Company

02/17/2016
Date (MM/DD/YYYY)

29704
P.E. Number

Place P.E. Seal or Stamp Here.

COMMONWEALTH OF MASSACHUSETTS
GEORGE S. LIPKA
SANITARY
No. 29704
REGISTERED
PROFESSIONAL ENGINEER

J. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained
in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete.
I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Mr. John Chillemi
Responsible Official Name (Type or Print)

J. Chillemi
Responsible Official Signature

President
Responsible Official Title

NRG Canal 3 Development LLC
Responsible Official Company/Organization Name

02/17/2016
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp.

K. Energy Efficiency Evaluation Survey

1. Do you know where your electricity and/or fuel and/or water and/or heat and/or compressed air is being used/consumed? ☒ Yes ☐ No

2. Has your facility had an energy audit performed by your utility supplier (or other)
in the past two years?[1] ☐ Yes ☒ No

   a. Did the audit include evaluations for heat loss, lighting load, cooling requirements and compressor usage? ☐ Yes ☒ No

   b. Did the audit influence how this project is configured? ☐ Yes ☒ No

3. Does your facility have an energy management plan? ☒ Yes ☐ No

   a. Have you identified and prioritized energy conservation opportunities? ☒ Yes ☐ No

   b. Have you identified opportunities to improve operating and maintenance procedures by employing an energy management plan? ☒ Yes ☐ No

4. Has each emission unit proposed herein been evaluated for energy consumption including average and peak electrical use; efficiency of electric motors and suitability of alternative motors such as variable speed; added heat load and/or added cooling load as a result of the operation of the proposed process; added energy load due to building air exchange requirements as a result of exhausting heat or emissions to the ambient air; and/or use of compressors? ☒ Yes ☐ No

5. Has your facility considered alternative energy methods such as solar, geothermal or wind power as a means of supplementing all or some of the facility's energy demand? ☒ Yes ☐ No

6. Does your facility comply with Leadership in Energy & Environmental Design (LEED) Green Building Rating System design recommendations?[2] ☐ Yes ☒ No (existing facility)

[1]A facility wide energy audit would include an inspection of such things as lighting, air-conditioning, heating, compressors and other energy-demand equipment. It would also provide you with information on qualifying equipment rebates and incentive programs; analysis of your energy consumption patterns and written cost-savings recommendations and estimated cost savings for installing new, high-efficiency equipment.

[2]To understand the LEED Rating System, it is important to become familiar with its comprising facets. To be considered for LEED New Construction and Major Renovations, a building must meet specific prerequisites and additional credit areas within six categories:

- Sustainable Sites
- Materials and Resources
- Water Efficiency
- Indoor Environmental Quality
- Energy and Atmosphere
- Innovation and Design

BWP AQ BACT

Determination of Best Available Control Technology (BACT)

Submit with Form CPA-FUEL and/or CPA-PROCESS, as applicable, when performing a top-down, case-by-case BACT analysis for your proposed Comprehensive Plan Application (CPA) project.

X269143
Transmittal Number

120-0054
Facility ID (if known)

Per 310 CMR 7.02(8)(a), this Form is not required to be submitted if:

- The proposed project will utilize Top-Case BACT (as defined by MassDEP); or
- Emissions from the proposed project are less than 18 tons of Volatile Organic Compounds and Halogenated Organic Compounds combined, less than 18 tons of total organic material Hazardous Air Pollutants (HAPs), and/or less than 10 tons of a single organic material HAP – all tonnages being per consecutive 12-month time period – AND the project proponent proposes a combination of best management practices, pollution prevention and a limitation on hours of operation and/or raw materials usage.

See the MassDEP BACT Guidance for additional information.

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

A. Project Information

1. Complete the table below to summarize your proposed air pollution control technology(ies)/ technique(s) to be used to deliver BACT for your proposed project, derived using a top-down BACT analysis as determined via Sections B, C, and D below:

Table 1

Emission Unit No.(s) Being Controlled	Proposed Air Pollution Control Device(s)/Technique(s)	Proposed Emission(s) Limit(s)
EU-11 (EDG)	Good combustion practices, low sulfur fuels	See MCPA Application Appendix A
EU-12 (FP)	Good combustion practices, low sulfur fuels	See MCPA Application Appendix A

B. Air Pollution Control Technology/Technique Options

Complete the table beginning on the next page for available, demonstrated in use, air pollution control technologies/techniques for this proposed project. List in order of lowest to highest resulting air contaminant(s) emissions.

To ensure a sufficiently broad and comprehensive search of control alternatives, sources other than the U.S. Environmental Protection Agency (EPA) RACT/BACT/LAER Clearinghouse database should be investigated and documented.

Copy and complete Table 2 as needed for your top options. Do not include any air pollution control technologies/techniques that result in higher air contaminant emissions than the technology/technique you are proposing.

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B. Air Pollution Control Technology/Technique Options (continued)

Table 2a - EU-11 (EDG)			
	Option 1:	**Option 2:**	**Option 3:**
Description of Available Air Pollution Control Technologies/Techniques	SCR	Oxidation Catalyst	Diesel Particulate Filter (DPF)
Pollutant(s) Controlled[1] (e.g. PM, NO_x, CO, SO_2, VOC, HAP)	NO_x	CO	PM
Potential Emissions Before Control (Pounds Per Hour, Pounds Per Million British Thermal Units, or Parts Per Million, Dry Volume Basis)	4.48 lb/hr	4.48 lb/hr	0.17 lb/hr
Resulting Emissions After Control (Pounds Per Hour, Pounds Per Million Btu, or Parts Per Million, Dry Volume Basis)	0.45 lb/hr	0.45 lb/hr	0.03 lb/hr
Annualized Cost in U.S. Dollars Per Ton of Pollutant Removed[2]	$60,634	$7,257	$984,110

[1] NO_x = nitrogen oxides, SO_2 = sulfur dioxide, VOC = volatile organic compounds, HAP = hazardous air pollutant, PM = particulate matter, CO = carbon monoxide

[2] Complete Section C of this Form to determine annualized costs.

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B. Air Pollution Control Technology/Technique Options (continued)

Table 2b - EU-12 (FP)			
	Option 1:	**Option 2:**	**Option 3:**
Description of Available Air Pollution Control Technologies/Techniques	SCR	Oxidation Catalyst	Diesel Particulate Filter (DPF)
Pollutant(s) Controlled[1] (e.g. PM, NO_x, CO, SO_2, VOC, HAP)	NO_x	CO	PM
Potential Emissions Before Control (Pounds Per Hour, Pounds Per Million British Thermal Units, or Parts Per Million, Dry Volume Basis)	0.89 lb/hr	1.11 lb/hr	0.074 lb/hr
Resulting Emissions After Control (Pounds Per Hour, Pounds Per Million Btu, or Parts Per Million, Dry Volume Basis)	0.09 lb/hr	0.11 lb/hr	0.011 lb/hr
Annualized Cost in U.S. Dollars Per Ton of Pollutant Removed[2]	$107,697	$12,597	$697,610

[1] NO_x = nitrogen oxides, SO_2 = sulfur dioxide, VOC = volatile organic compounds, HAP = hazardous air pollutant, PM = particulate matter, CO = carbon monoxide

[2] Complete Section C of this Form to determine annualized costs.

C. Annualized Cost Analysis

Complete the table below for each air pollution control technology/technique being evaluated for this proposed project. Whenever possible, use vendor quotes. Do not complete this table for those air pollution control technologies/techniques that result in higher air contaminant emissions than those you are proposing.

Table 3a - EU-11 (EDG)			
	Option 1	**Option 2**	**Option 3**
Total Capital Investment (TCI)			
Direct Purchase Cost			
1. Primary Control Device & Auxiliary Equipment	$100,000	$10,000	$60,000
2. Fans	Included	Included	Included
3. Ducts	Included	Included	Included
4. Other – Specify: Direct Installation Costs	$31,500	$3,150	$18,900
5. Instrumentation/Controls	Included	Included	Included
Indirect Capital Cost			
6. Construction	$15,750	$1,575	$9,450
7. Labor	Included	Included	Included
8. Sales Taxes	$5,000	$500	$3,000
9. Freight Charges	Included	Included	Included
Engineering/Planning			
10. Contracting Fees	Included	Included	Included
11. Testing	$3,150	$315	$1,890
12. Supervision	$10,500	$1,050	$6,300
13. Total Capital Investment (Add 1 Through 12)	$165,900	$16,590	$99,540
14. Annualized Capital Cost: $C[i(1+i)^n]/[(1+i)^n - 1]$*	$27,042	$2,704	$16,225

* C = Total Capital Investment (Line 13) i = Interest Rate (Assume 10%) n = Life of Equipment (Assume 10 Years or Less)

C. Annualized Cost Analysis (continued)

Table 3a - EU-11 (EDG) (Continued)			
	Option 1	Option 2	Option 3
Annual Operating & Maintenance Costs			
Direct Operating Cost			
15. Labor	$480	$240	$240
16. Maintenance	$960	$480	$480
17. Replacement Parts	$0	$0	$0
Indirect Cost			
18. Property Taxes*	$1,659	$166	$995
19. Insurance	$1,659	$166	$995
20. Fees	$3,894	$620	$2,279
21. Total Annual Operating Costs (Add 15 Through 20)	$8,652	$1,672	$4,989
Energy Cost			
22. Annual Electrical Energy Expense	$0	$0	$0
23. Annual Auxiliary Fuel Cost	$0	$0	$0
24. Total Annual Energy Cost (Add 22 and 23)	$0	$0	$0
25. Annual Waste Treatment & Disposal Costs	$0	$0	$0
26. Miscellaneous Annual Expenses (Ammonia for SCR)	$868	$0	$0
27. Annual Resource Recovery & Resale	$0	$0	$0
28. Total Annualized Control Costs (14+21+24+25+26) - 27	$36,562	$4,376	$21,214
29. Amount of Pollutant Controlled Over Baseline Emissions** (Tons Per Year)	0.60	0.603	0.0216
30. Cost of Control (Dollars Per Ton) (Divide 28 By 29)	$60,634	$7,257	$984,110

*State and federal law may provide for certain tax exemptions and special loans for the purchase of control equipment. Contact the Massachusetts Industrial Finance Agency (MIFA) or Federal Small Business Association (SBA).

BWP AQ BACT

Determination of Best Available Control Technology (BACT)

Submit with Form CPA-FUEL and/or CPA-PROCESS, as applicable, when performing a top-down, case-by-case BACT analysis for your proposed Comprehensive Plan Application (CPA) project.

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C. Annualized Cost Analysis

Complete the table below for each air pollution control technology/technique being evaluated for this proposed project. Whenever possible, use vendor quotes. Do not complete this table for those air pollution control technologies/techniques that result in higher air contaminant emissions than those you are proposing.

Table 3b - EU-12 (FP)			
	Option 1	**Option 2**	**Option 3**
Total Capital Investment (TCI)			
Direct Purchase Cost			
1. Primary Control Device & Auxiliary Equipment	$30,930	$2,729	$16,375
2. Fans	Included	Included	Included
3. Ducts	Included	Included	Included
4. Other – Specify: Direct Installation Costs	$9,743	$860	$5,158
5. Instrumentation/Controls	Included	Included	Included
Indirect Capital Cost			
6. Construction	$4,872	$430	$2,579
7. Labor	Included	Included	Included
8. Sales Taxes	$1,546	$136	$819
9. Freight Charges	Included	Included	Included
Engineering/Planning			
10. Contracting Fees	Included	Included	Included
11. Testing	$975	$86	$516
12. Supervision	$3,248	$287	$1,719
13. Total Capital Investment (Add 1 Through 12)	$51,313	$4,528	$27,166
14. Annualized Capital Cost: $C[i(1+i)^n]/[(1+i)^n - 1]$*	$8,364	$738	$4,428

* C = Total Capital Investment (Line 13) i = Interest Rate (Assume 10%) n = Life of Equipment (Assume 10 Years or Less)

C. Annualized Cost Analysis (continued)

Table 3b - EU-12 (FP) (Continued)			
	Option 1	**Option 2**	**Option 3**
Annual Operating & Maintenance Costs			
Direct Operating Cost			
15. Labor	$480	$240	$240
16. Maintenance	$960	$480	$480
17. Replacement Parts	$0	$0	$0
Indirect Cost			
18. Property Taxes*	$513	$45	$272
19. Insurance	$513	$45	$272
20. Fees	$1,602	$379	$831
21. Total Annual Operating Costs (Add 15 Through 20)	$4,068	$1,189	$2,095
Energy Cost			
22. Annual Electrical Energy Expense	$0	$0	$0
23. Annual Auxiliary Fuel Cost	$0	$0	$0
24. Total Annual Energy Cost (Add 22 and 23)	$0	$0	$0
25. Annual Waste Treatment & Disposal Costs	$0	$0	$0
26. Miscellaneous Annual Expenses (Ammonia)	$168	$0	$0
27. Annual Resource Recovery & Resale	$0	$0	$0
28. Total Annualized Control Costs (14+21+24+25+26) - 27	$12,601	$1,927	$6,523
29. Amount of Pollutant Controlled Over Baseline Emissions** (Tons Per Year)	0.117	0.153	0.00935
30. Cost of Control (Dollars Per Ton) (Divide 28 By 29)	$107,697	$12,597	$697,610

*State and federal law may provide for certain tax exemptions and special loans for the purchase of control equipment. Contact the Massachusetts Industrial Finance Agency (MIFA) or Federal Small Business Association (SBA).

** Baseline Emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions.

D. Option Feasibility

Complete the table below to summarize the basis for elimination of each of the air pollution control technologies/techniques used to determine BACT for your proposed project:

Table 4

Description of Air Pollution Control Technology/Technique Option	Explain the Basis for Elimination[1]
EU-11 Option 1 (SCR)	Not Demonstrated in Practice on an Emergency Unit , Economically Infeasible
EU-11 Option 2 (Oxidation Catalyst)	Economically Infeasible
EU-11 Option 3 (DPF)	Economically Infeasible
EU-12 Option 1 (SCR)	Not Demonstrated in Practice on an Emergency Unit , Economically Infeasible
EU-12 Option 2 (Oxidation Catalyst)	Economically Infeasible
EU-12 Option 3 (DPF)	Economically Infeasible

[1] **Note:** BACT is defined as an emission limitation based on the maximum degree of reduction of any regulated air contaminant emitted from or which results from any regulated facility which MassDEP, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable. Explanations will be based upon the following:

Technical Reasons. Must specifically state the reason(s) why the option is not technically feasible and specifically why the option cannot be modified to accommodate the proposed emission unit(s).

Economic Reason. Final determination will be based on U.S. Environmental Protection Agency methods or other methods approved by MassDEP.

Other Reasons. Must specifically state the reason(s) why the option is not feasible and specifically why the option cannot be modified to accommodate the proposed emission unit(s).

E. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

George S. Lipka
P.E. Name (Type or Print)

George S. Lipka
P.E. Signature

Consulting Engineer
Position/Title

Tetra Tech
Company

02/17/2016
Date (MM/DD/YYYY)

29704
P.E. Number

Place P.E. Seal or Stamp Here.

COMMONWEALTH OF MASSACHUSETTS
GEORGE S. LIPKA
SANITARY
No. 29704
REGISTERED
PROFESSIONAL ENGINEER

F. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Mr. John Chillemi
Responsible Official Name (Type or Print)

[signature]
Responsible Official Signature

President
Responsible Official Title

NRG Canal 3 Development LLC
Responsible Official Company/Organization Name

02/17/2016
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ Selective Catalytic Reduction

Submit with Form CPA-FUEL and/or CPA-PROCESS whenever construction, substantial reconstruction or alteration of a Selection Catalytic Reduction system is proposed unless exempt per 310 CMR 7.02(2)(b).

X269143
Transmittal Number

120-0054
Facility ID (if known)

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

A. Inlet Operating Conditions

1. Complete the table below with information on inlet gas flow(s).

Table 1a			
Emission Unit No(s). Being Controlled	**Average Inlet Gas Flow** (Actual Cubic Feet Per Minute)	**Inlet Temperature** (Degrees Fahrenheit (ºF))	**Moisture Content in the Inlet** (Pounds Per Minute)
EU-10 (CTG)	4,341,180 firing gas at ISO condition (gas firing)	900	5,684 firing gas at ISO condition (gas firing)
Totals:			

2. Which metals/elements are present in gas stream?

☐ Potassium ☐ Arsenic ☐ Lead
☐ Zinc ☐ Sodium ☐ Phosphorus

3. Are there any other catalyst binding agents present in the gas stream?

☐ Yes – Describe Below ☒ No

4. Complete the table below to provide the maximum oxides of nitrogen (NOx) emissions:

Table 2		
Emission Unit No(s). Being Controlled	**Inlet NOx** (Pounds Per Hour)	**Inlet NOx** (Parts Per Million by Volume, Dry Basis)
EU-10 (CTG)	Up to 310 gas, 566 ULSD	25.0 ppmvdc gas 42.0 ppmvdc ULSD

Continue to Next Page ►

BWP AQ Selective Catalytic Reduction

Submit with Form CPA-FUEL and/or CPA-PROCESS whenever construction, substantial reconstruction or alteration of a Selection Catalytic Reduction system is proposed unless exempt per 310 CMR 7.02(2)(b).

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B. Specifications

1. Manufacturer of Selective Catalytic Reduction (SCR) system: TBD
   Company
2. Model Number (or Equivalent): Custom
   Number
3. Location of SCR unit relative to other pieces of equipment: ☐ High Dust ☐ Low Dust ☒ Tail End
4. Information about the catalyst used:
   a. Description of catalyst: TBD
      Description
   b. Operating temperature range of catalyst: from 500 (startup) Degrees Fahrenheit (°F) to 900 (design) Degrees Fahrenheit (°F)
   c. Pressure drop across the catalyst: 20
      Inches of Water

5a. Number of catalyst layers the system can accommodate: TBD
Number

5b. Number of catalyst layers that will be installed: TBD
Number

6. Does the SCR system employ a guard bed for catalyst protection? ☐ Yes ☒ No*

   *If No, explain:

   Not required for natural gas and limited ULSD combustion

7. Expected catalyst life: 5 years
   Years
8. Operating hours per layer of catalyst: TBD
   Hours
9. Can the catalyst be reactivated? ☐ Yes * ☒ No

   *If Yes, describe how:

10. Catalyst cleaning method: ☐ Compressed Air Soot Blower ☐ Steam Soot Blower ☐ Sonic Horns ☒ Other – Describe: N/A
11. Describe SCR system dust management technologies and strategies being used, if any (e.g. ash screens):

    Not required for natural gas and limited ULSD combustion

B. Specifications (continued)

12. Are you proposing a by-pass stack? ☐ Yes * ☒ No

*If Yes, describe:

C. Description of Reducing Agent

1. Type and form of reducing agent proposed: ☐ Gaseous ☐ Liquid ☐ Anhydrous Ammonia ☒ Aqueous Ammonia ☐ Urea ☐ Other – Describe:

2. If liquid, provide weight percent in solution: 19
Weight Percent

3. Method of reducing agent injection: ☐ Direct Injection ☒ Injection Grid

4. Describe in detail how the concentration and usage rate of the reducing agent were determined. Continue on a separate attachment, if necessary.
19 percent aqueous ammonia has become accepted in the industry by precedent.

5. Describe the process controls for proper mixing of the reducing agent in the gas stream. Continue on a separate attachment, if necessary.
SCR OEM supplier provides system for metering liquid, evaporation to vapor, and injection and distribution in the gas stream by injection grid with multiple orifices vertically and horizontally distributed across duct.

6. Describe storage of the reagent, including details about any storage containment (e.g. dimension of berms, evaporative mitigation). Continue on a separate attachment, if necessary.
19% solution stored in existing tanks provided with spill containment

7. Is the reagent subject to 42 U.S.C. 7401, Section 112(r)? ☐ Yes * ☒ No

*If Yes, attach a copy of the Risk Management Plan to this form.

8. You MUST attach to this form a copy of an analysis of possible impacts to off-property locations from a catastrophic release of the reducing agent, in comparison with American Industrial Hygiene Association Emergncy Response Planning Guidelines.

D. Emissions Data

1. Complete the table below to provide maximum oxides of nitrogen (NOx) and ammonia (NH_3) slip concentrations and emission rates:

Table 3		
Air Contaminant	**Outlet** (Pounds Per Hour)	**Outlet**[1] (Parts Per Million By Volume, Dry Basis)
NOx	Up to 31.5 gas, 67.3 ULSD	2.5 ppmvdc gas 5.0 ppmvdc ULSD
NH_3	Up to 23.3 gas, 25.0 ULSD	5.0 ppmvdc gas* 5.0 ppmvdc ULSD

[1]Boilers at 3% oxygen; combustion turbines at 15% oxygen; engines at 15% oxygen. *optimization goal 2.0 ppmvdc on gas

2. Explain how the above NOx and NH_3 emissions data were obtained. Attach appropriate calculations and documentation.

   Emission rates are based on guaranteed outlet concentrations from turbine vendor. See Appendix B of this application for detailed emission calculations

E. Drawing of Selective Catalytic Reduction System

You must attach to this form a schematic drawing of the proposed Selective Catalytic Reduction system. At a minimum, it must show the location(s) of the catalyst bed(s), bypass damper(s) if applicable, bypass stack if applicable, and normal stack. Sampling ports for emissions testing must also be shown.

Note: You must notify the BWP Compliance & Enforcement Chief in the appropriate MassDEP regional office by telephone as soon as possible, within but no later than one (1) business day after you discover any upset or malfunction to facility equipment that results in excess emissions to the air and/or a condition of air pollution. You must submit written notice within seven (7) days thereafter.

F. Monitoring, Record Keeping & Failure Notification

1. Provide the manufacturer, make and model number of the proposed continuous emissions and opacity monitoring systems:

   Make and model of CEMS not yet selected

2. Identify the air contaminants that will be continuously monitored and recorded (e.g. NOx, NH_3, opacity)

   NO_x, CO, NH_3, opacity, O_2

3. Describe any proposed process monitors (e.g. ammonia injection, fuel combustion) and frequency of data recording:

   Plant control system and data logger will record fuel flow rate, MW load, and ammonia injection rate; 1-minute data recording and 1-hour data averaging.

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F. Monitoring, Record Keeping & Failure Notification (continued)

4. Are there any alarms associated with the monitoring equipment? ☒ Yes – Complete Table 4 ☐ No – Explain Below

Table 4			
Operating Parameter Monitored	**Describe Alarm Trigger**	**Monitoring Device or Alarm Type**	**Does the Alarm Initiate an Automated Response?**
NOx	Out of compliance detected by CEMS	☒ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☒ No If Yes, Describe:
CO	Out of compliance detected by CEMS	☒ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☒ No If Yes, Describe:
NH3	Out of compliance detected by CEMS	☒ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☒ No If Yes, Describe:

5. Describe the operating conditions that are monitored to determine the reducing agent injection rate:

   Aqueous ammonia injection rate mass flow

6. How often will the catalyst be tested and by what test method (e.g. core sample)?

   TBD

7. List and explain all of the operating and safety controls associated with the SCR system. Continue on a separate attachment, if necessary.

   If inlet temperatures exceed allowable limits, alarm will sound. Operator will reduce load or shut down unit. Ammonia injection is maintained only when acceptable gas temperature is maintained.

8. List the SCR system emergency procedures to be used during system upsets. Continue on a separate attachment, if necessary.

   TBD

F. Monitoring, Record Keeping & Failure Notification (continued)

9. Explain the typical fluctuations in SCR system operation, such as changes in effluent temperatures, flow rates, pollutant concentrations, etc., which may affect operation of the unit. Also explain the means by which control efficiency will be maintained throughout these fluctuations. Continue on a separate attachment, if necessary.

   SCR control logic automatically meters ammonia injection to maintain stack exit concentration set points.

10. Describe the record keeping procedures to be used in identifying the cause, duration and resolution of each system failure/emission(s) exceedance. Continue on a separate attachment, if necessary.

    TBD

11. How will the SCR system be designed so as to allow for emissions testing using MassDEP-sanctioned test methods?

    The exhaust stack will be fitted with platforms and test ports to allow stack testing using MassDEP-sanctioned test methods.

G. Standard Operating & Maintenance Procedures

Attach to this form the standard operating and maintenance procedures for the proposed Selective Catalytic Reduction system, as well as a list of the spare parts inventory that you will maintain on site, as recommended by the equipment vendor.

Standard Operating and Maintenance Procedures will be provided after selection of the SCR system vendor.

H. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

George S. Lipka
P.E. Name (Type or Print)

George S Lipka
P.E. Signature

Consulting Engineer
Position/Title

Tetra Tech
Company

02/17/2016
Date (MM/DD/YYYY)

29704
P.E. Number

Place P.E. Stamp Here

COMMONWEALTH OF MASSACHUSETTS
GEORGE S. LIPKA
SANITARY
No. 29704
REGISTERED
PROFESSIONAL ENGINEER

I. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Mr. John Chillemi
Responsible Official Name (Type or Print)

J Chill.
Responsible Official Signature

President
Responsible Official Title

NRG Canal 3 Development LLC
Responsible Official Company/Organization Name

02/17/2016
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp.

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ Afterburner/Oxidizer

Submit with Form CPA-PROCESS whenever construction, substantial reconstruction or alteration of an Afterburner/Oxidizer is proposed unless exempt per 310 CMR 7.02(2)(b).

X269143
Transmittal Number

120-0054
Facility ID (if known)

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

A. Inlet Operating Conditions

1. Complete the tables below with information on inlet gas flow(s).

Table 1a

Emission Unit No(s). Being Controlled	**Average Inlet Gas Flow** (Actual Cubic Feet Per Minute)	**Moisture Content in the Inlet** (Pounds Per Minute)	**Inlet Temperature** (Degrees Fahrenheit (ºF))	**Inlet Velocity** (Feet Per Second)
EU-10 (CTG)	4,341,180 firing gas at ISO condition	5,684 firing gas at ISO condition	900	TBD

Table 1b

Provide the Maximum Gaseous Emissions			
Emission Unit No(s). Being Controlled	**Air Contaminant** (e.g. VOC, HAP, PM)*	**Air Contaminant Range Before Control** (Pounds Per Hour)[1]	**Air Contaminant Range Before Control** (Parts Per Million, Dry Basis)[1]
EU-10 (CTG)	CO	Up to 49.2 gas,108 ULSD	9 ppmvd gas 20 ppmvd ULSD
EU-10 (CTG)	VOC	Up to 4.8 gas,12.2 ULSD	1.4 ppmvw gas 3.5 ppmvw ULSD

[1] Estimated by vendor, not guaranteed
*VOC = Volatile Organic Compounds; HAP = Hazardous Air Pollutant(s)' PM = Particulate Matter

2. Provide the capture efficiency of the ventilation system serving the Afterburner/Oxidizer. The presumption is that the capture efficiency of the system meets the criteria of the Permanent Total Enclosure (PTE) detailed in EPA Method 204.

   100 %
   Weight Percent (%)

3. If the proposed system does not meet the PTE criteria, explain:

BWP AQ Afterburner/Oxidizer

Submit with Form CPA-PROCESS whenever construction, substantial reconstruction or alteration of an Afterburner/Oxidizer is proposed unless exempt per 310 CMR 7.02(2)(b).

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Facility ID (if known)

B. Specifications

1. Manufacturer of Afterburner/Oxidizer: TBD
   Company
2. Model Number (or Equivalent): TBD
   Number
3. Type of Afterburner/Oxidizer: ☐ Recuperative ☐ Regenerative ☒ Catalytic ☐ Direct Flame

4a. If Regenerative, will there be a "puff" chamber? ☐ Yes ☐ No

4b. If Regenerative, describe how efficiency will be maintained when switching beds:

N/A

5a. If Catalytic, describe the unit:

TBD

5b. If Catalytic, provide dimensions of the bed:

TBD Height (Inches)	TBD Width (Inches)
TBD Depth (Inches)	TBD Weight (Pounds)

5c. If Catalytic, pressure drop range across the bed: TBD
Inches of Water

6. Capacity of the Afterburner/Oxidizer: ≥1,746,414
   Standard Cubic Feet Per Minute
7. Temperature at the Afterburner/Oxidizer outlet: 900
   Degrees Fahrenheit (ºF)
8. Outlet gas exhaust flow rate: 4,341,180 firing gas at ISO condition
   Actual Cubic Feet Per Minute, Wet
9. Proposed minimum operating temperature of the Afterburner/Oxidizer, as measured at the downstream end of the combustion chamber: N/A
   Degrees Fahrenheit (ºF)
10. Combustion chamber temperature control mechanism: N/A
    Describe
11. Minimum residence time of gases in combustion chamber at the minimum temperature: TBD
    Seconds
12. Explain the design and operation of any heat recovery system associated with this Afterburner/Oxidizer system. Continue on a separate attachment, if necessary.

None

Notes:
- The burner must be able to maintain this minimum operating temperature without the benefit of the heating value of contaminants in the waste stream.
- Design calculations must be submitted that incorporate fuel, air and waste stream supply rates as well as heat transfer phenomena (including heat recovery systems) used to determine the minimum gas temperature and residence time in the combustion chamber.

BWP AQ Afterburner/Oxidizer

Submit with Form CPA-PROCESS whenever construction, substantial reconstruction or alteration of an Afterburner/Oxidizer is proposed unless exempt per 310 CMR 7.02(2)(b).

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Facility ID (if known)

C. Fuel & Burner Data

1. Provide the burner manufacturer(s) and model number(s):

N/A
Manufacturer(s)

N/A
Model Number(s)

2. Type of Gaseous Fuel Used: ☐ Natural Gas ☐ Propane ☐ Other - Specify:

3a. Gas firing rate:

N/A
Maximum Cubic Feet Per Hour

N/A
Minimum Cubic Feet Per Hour

3b. Maximum heat input rate:

N/A
British Thermal Units (Btu) Per Hour

4. Describe burner design and explain how proper mixing of fuel and combustion air will be achieved:

N/A

5. Describe the burner modulation system (e.g. full modulating, high/low, on/off):

N/A

6. If on/off modulation will be used, describe how the minimum operating temperature will be maintained at all times:

N/A

7. Describe what portion of the contaminant stream will bypass the burner to be mixed with the flame downstream:

N/A

Continue to Next Page ►

BWP AQ Afterburner/Oxidizer

Submit with Form CPA-PROCESS whenever construction, substantial reconstruction or alteration of an Afterburner/Oxidizer is proposed unless exempt per 310 CMR 7.02(2)(b).

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Facility ID (if known)

D. Emissions Data

1. Describe air contaminant emissions after control by the proposed Afterburner/Oxidizer:

Table 2			
Provide the Maximum Gaseous Emission Rate			
Emission Unit No(s). Being Controlled	**Air Contaminant**	**Air Contaminant Emission Range After Control** (Pounds Per Hour)[1]	**Air Contaminant Emission Range After Control** (Parts Per Million by Volume, Dry Basis)[1]
EU-10 (CTG)	CO	Up to ***27.1*** gas, 41.0 ULSD	***3.5*** ppmvdc 5.0 ppmvdc ULSD
EU-10 (CTG)	VOC	Up to 8.9 gas, 9.4 ULSD	2.0 ppmvdc gas 2.0 ppmvdc ULSD

[1] Vendor guarantee

2. Explain how the above air contaminant emissions data were obtained. Attach appropriate calculations and documentation.

Emission rates are based on guaranteed outlet concentrations from turbine vendor. See Appendix B of this application for detailed emission calculations

3a. Design destruction efficiency of organic compounds (as carbon) in the Afterburner/Oxidizer: N/A
Weight Percent (%)

3b. Explain how this efficiency was calculated or determined:

Based on guaranteed emission rates from turbine vendor.

4a. Design destruction efficiency for inorganic hazardous air pollutants in the Afterburner/Oxidizer: N/A
Weight Percent (%)

4b. Explain how this efficiency was calculated or determined:

N/A

E. Catalytic Units Only

1. Estimated useful life of the catalyst: 5 years
   Amount of Time (e.g. Months or Years)

2. Describe how catalyst performance will be monitored, including the test method and frequency of testing:

   CO CEMS at stack to demonstrate compliance with BACT emission rate

F. Drawing of Afterburner/Oxidizer Control System

You must attach to this form a schematic drawing of the proposed Afterburner/Oxidizer. At a minimum, it must show the location(s) of the burner(s), catalyst bed(s), bypass damper(s), bypass stack and normal stack. Clearly indicate the gas circulation pattern through preheat and burner chambers, and through heat recovery unit(s) prior to ambient discharge. Sampling ports for emissions testing, and location of each pressure and temperature indicator must also be shown.

Note: You must notify the BWP Compliance & Enforcement Chief in the appropriate MassDEP regional office by telephone as soon as possible, within but no later than one (1) business day after you discover any upset or malfunction to facility equipment that results in excess emissions to the air and/or a condition of air pollution. You must submit written notice within seven (7) days thereafter.

G. Monitoring, Record Keeping & Failure Notification

1. Describe the parameters that will be monitored as a surrogate for control device efficiency, and the frequency of monitoring. Continue on a separate attachment, if necessary.

   CO CEMS at stack to demonstrate compliance with BACT emission rate.

2. Describe the monitoring methods and warning/alarm system that protect against operation when the unit is not meeting design efficiency (e.g. visual monitoring, audible alarm, flashing lights, temperature indicator, pressure indicator). Continue on a separate attachment, if necessary.

   CO CEMS at stack to demonstrate compliance with BACT emission rate. All exceedances will be documented and reported in quarterly excess emissions reports. A visual alarm will be triggered by the CEMS if CO is detected to be out of compliance with emission limits.

3. Describe the record keeping procedures to be used to verify monitoring and to identify the cause, duration and resolution of each failure. Continue on a separate attachment, if necessary.

   CO CEMS data acquisition and handling system (DAHS) to record all CEMS measurements and quality assurance data.

Continue to Next Page ►

G. Monitoring, Record Keeping & Failure Notification (continued)

4. Describe how failure of the Afterburner/Oxidizer will be made known to the operator during normal operations (e.g. visual monitoring, audible alarm, flashing lights, time indicator, pressure indicator). Continue on a separate attachment, if necessary.

   A visual alarm will be triggered by the CEMS if CO is detected to be out of compliance with emission limits.

5. List and explain all operating and safety controls associated with this system, including interlock systems that prevent introduction of the air contaminant(s) stream until the Afterburner/Oxidizer is operating properly. Continue on a separate attachment, if necessary.

   The oxidation catalyst is passive, and there is no bypass for the exhaust stream. During unit startups, heat from the exhaust will warm the catalyst to its required operating temperature range.

6. Describe the Afterburner/Oxidizer's emergency procedures during system upsets. Continue on a separate attachment, if necessary.

   The oxidation catalyst is passive, and therefore no emergency procedures are required during system upsets.

7. Describe features of the system design that will allow for emissions testing and operation using MassDEP-sanctioned test methods. Continue on a separate attachment, if necessary.

   The exhaust stack will be fitted with platforms and test ports to allow stack testing using MassDEP-sanctioned test methods.

H. Standard Operating & Maintenance Procedures

Attach to this form the standard operating and maintenance procedures for the proposed Afterburner/Oxidizer, as well as a list of the spare parts inventory that you will maintain on site, as recommended by the equipment vendor(s).

Standard Operating and Maintenance Procedures will be provided after selection of the oxidation catalyst system vendor.

Continue to Next Page ►

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention – Air Quality

BWP AQ Afterburner/Oxidizer

Submit with Form CPA-PROCESS whenever construction, substantial reconstruction or alteration of an Afterburner/Oxidizer is proposed unless exempt per 310 CMR 7.02(2)(b).

X269143
Transmittal Number

120-0054
Facility ID (if known)

I. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

George S. Lipka
P.E. Name (Type or Print)

George S Lipka
P.E. Signature

Consulting Engineer
Position/Title

Tetra Tech
Company

02/17/2016
Date (MM/DD/YYYY)

29704
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
GEORGE S. LIPKA
SANITARY
No. 29704
REGISTERED
PROFESSIONAL ENGINEER

Place P.E. Seal or Stamp Here.

J. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Mr. John Chillemi
Responsible Official Name (Type or Print)

J Chill.
Responsible Official Signature

President
Responsible Official Title

NRG Canal 3 Development LLC
Responsible Official Company/Organization Name

02/17/2016
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp.

BWP AQ Sound

Submit alone and/or with Form CPA-FUEL and/or CPA-PPROCESS whenever the construction or alteration of stationary equipment (e.g. electrical generating equipment, motors, fans, process handling equipment or similar sources of sound) has the potential to cause noise, or in response to a MassDEP enforcement action citing noise as a condition of air pollution.

X269143
Transmittal Number

120-0054
Facility ID (if known)

Important: When filling out forms on the computer, use only the tab key to move your cursor - do not use the return key.

tab

return

Introduction

When proposing sound suppression/mitigation measures, similar to the traditional "top-down" BACT process, the "top case" sound suppression/mitigation measures which deliver the lowest sound level increase above background are required to be implemented, unless these measures can be eliminated based upon technological or economic infeasibility. An applicant cannot "model out" of the use of the "top case" sound suppression/ mitigation measures by simply demonstrating that predicted sound levels at the property line when employing a less stringent sound suppression/mitigation strategy will result in a sound level increase of less than or equal to the 10 dBA (decibel, A –Weighted) above background sound level increase criteria contained in the MassDEP Noise Policy. A 10 dBA increase is the maximum increase allowed by MassDEP; it is not the sound level increase upon which the design of sound suppression/mitigation strategies and techniques should be based. Also, take into consideration that the city or town that the project is located in may have a noise ordinance (or similar) that may be more stringent than the criteria in the MassDEP Noise Policy

A. Sound Emission Sources & Abatement Equipment/Mitigation Measures

1. Provide a description of the source(s) of sound emissions and associated sound abatement equipment and/or mitigation measures. Also include details of sound emission mitigation measures to be taken during construction activities.

   See Section 7.0 of MCPA

B. Manufacturer's Sound Emission Profiles & Sound Abatement Equipment

Please attach to this form the manufacturer's sound generation data for the equipment being proposed for installation, or the existing equipment as applicable. This data must specify the sound pressure levels for a complete 360° circumference of the equipment and at given distance from the equipment. Also attach information provided by the sound abatement manufacturer detailing the expected sound suppression to be provided by the proposed sound suppression equipment.

See Table 7-1 of MCPA

C. Plot Plan

Provide a plot plan and aerial photo(s) (e.g. GIS) that defines: the specific location of the proposed or existing source(s) of sound emissions; the distances from the source(s) to the property lines; the location, distances and use of all inhabited buildings (residences, commercial, industrial, etc) beyond the property lines; identify any areas of possible future construction beyond the property line; and sound monitoring locations used to assess noise impact on the surrounding community. All information provided in the sound survey shall contain sufficient data and detail to adequately assess any sound impacts to the surrounding community, including elevated receptors as applicable, not necessarily receptors immediately outside the facility's property line.

See Figure 7-1 of MCPA

Continue to Next Page ►

D. Community Sound Level Criteria

Approval of the proposed new equipment or proposed corrective measures will **not** be granted if the installation:

1. Increases off-site broadband sound levels by more than 10 dBA.above “ambient” sound levels. Ambient is defined as the lowest one-hour background A-weighted sound pressure level that is exceeded 90 percent of the time measured during equipment operating hours. Ambient may also be established by other means with the consent of MassDEP.
2. Produces off-site a "pure tone" condition. “Pure tone” is defined as when any octave band center frequency sound pressure level exceeds the two adjacent frequency sound pressure levels by 3 decibels or more.
3. Creates a potential condition of air pollution as defined in 310 CMR 7.01 and the MassDEP Noise Policy.

Note: These criteria are measured both at the property line and at the nearest inhabited building.

For equipment that operates, or will be operated intermittently, the ambient or background noise measurements shall be performed during the hours that the equipment will operate and at the quietest times of the day. The quietest time of the day is usually between 1:00 a.m. and 4:00 a.m. on weekend nights. The nighttime sound measurements must be conducted at a time that represents the lowest ambient sound level expected during all seasons of the year.

For equipment that operates, or will operate, continuously and is a significant source of sound, such as a proposed power plant, background shall be established via a minimum of seven consecutive days of continuous monitoring at multiple locations with the dBA L 90 data and pure tone data reduced to one-hour averages.

In any case, consult with the appropriate MassDEP Regional Office before commencing noise monitoring in order to establish a sound monitoring protocol that will be acceptable to MassDEP.

E. Full Octave Band Analysis

The following community sound profiles will require the use of sound pressure level measuring equipment in the neighborhood of the installation. An ANSI S1.4 Type 1 sound monitor or equivalent shall be use for all sound measurements. A detailed description of sound monitor calibration methodology shall be included with any sound survey.

1. Lowest **ambient** sound pressure levels during operating hours of the equipment.

   a. At property line:

A-Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
SW - 45 dBA	53	50	52	45	41	38	37	31	28	
NE - 44 dBA	50	48	47	44	40	40	37	31	25	

E. Full Octave Band Analysis (continued)

b. At the nearest inhabited building and if applicable at buildings at higher elevation:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
ST1 - 41 dBA	48	51	50	40	39	37	28	18	14	
ST2 - 40 dBA	52	50	45	39	39	34	26	18	13	
ST3 - 40 dBA	49	51	53	37	35	34	28	22	15	
ST6 - 34 dBA	44	43	37	32	34	29	18	12	13	

Note: You are required to complete sound profiles 2a and 2b only if you are submitting this form in response to a MassDEP enforcement action citing a noise nuisance condition. If this is an application for new equipment, Skip to 3.

2. Neighborhood sound pressure levels with source operating without sound abatement equipment.

NA, source will not operate without sound abatement equipment

a. At property line:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K

b. At the nearest inhabited building and if applicable at buildings at higher elevation:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K

Continue to Next Page ►

E. Full Octave Band Analysis (continued)

3. **Expected** neighborhood sound pressure levels after installation of sound abatement equipment.

a. At property line:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
SW - 53 dBA	73	70	61	50	47	45	44	41	29	
NE - 50 dBA	73	71	59	48	44	43	40	36	25	

b. At nearest inhabited building and if applicable at buildings at higher elevations:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
ST1 - 47 dBA	67	65	56	45	43	40	35	29	14	
ST2 - 47 dBA	69	67	57	45	43	39	36	28	13	
ST3 - 43 dBA	65	63	55	40	37	35	30	23	15	
ST6 - 39 dBA	63	60	48	37	36	32	25	14	13	

Note: MassDEP may request that actual measurements be taken after the installation of the noise abatement equipment to verify compliance at all off-site locations.

F. Professional Engineers Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

George S. Lipka
P.E. Name (Type or Print)

George S Lipka
P.E. Signature

Consulting Engineer
Position/Title

Tetra Tech, Inc.
Company

02/17/2016
Date (MM/DD/YYYY)

29704
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
GEORGE S. LIPKA
SANITARY
No. 29704
REGISTERED
PROFESSIONAL ENGINEER

G. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

Mr. John Chillemi
Responsible Official Name (Type or Print)

JCllll
Responsible Official Signature

President
Responsible Official Title

NRG Canal 3 Development, LLC
Responsible Official Company/Organization Name

02/17/2016
Date (MM/DD/YYYY)

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APPENDIX B: EMISSION CALCULATIONS

Appendix B, Table B-1
Combustion Turbine Exhaust Data for GE7HA.02
Natural Gas Firing

OPERATING POINT		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
SITE CONDITIONS																	
Ambient Temperature	°F	90	90	90	90	59	59	59	50	50	50	20	20	20	0	0	0
Ambient Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Relative Humidity	%	56	56	56	56	60	60	60	60	60	60	66	66	66	40	40	40
Evaporative Cooler state (On or Off)		On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
Gas Turbine Load	%	BASE	BASE	75%	38%	BASE	75%	30%	BASE	75%	30%	BASE	75%	30%	BASE	75%	40%
GT Diluent Injection Type		None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None
GT Diluent Injection Flow (per GT)	10^3 lb/hr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Type		NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
HHV	BTU/lb	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882	23882
LHV	BTU/lb	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515	21515
Fuel Mol. Wt.	lb/mole	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Fuel Bound Nitrogen	Wt %	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Sulfur Content	ppmw	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
GT Heat Consumption (HHV Basis)	MMBTU/hr	3272	3150	2485	1609	3256	2580	1489	3323	2628	1513	3414	2714	1574	3425	2743	1869
Attemperated Flue Gas Temperature	°F	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Attemperated Flue Gas Flow	ft3/sec	75,001	73,343	60,043	44,682	72,353	59,784	41,547	72,985	60,099	41,708	72,246	59,983	42,114	70,783	59,555	46,558

Stack Emissions

NOx (ppmvdc design BACT)	ppmvdc	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MMBtu	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092
	lb/hr	30.10	28.98	22.86	14.80	29.95	23.73	13.70	30.58	24.17	13.92	31.41	24.97	14.48	31.51	25.24	17.19
CO (ppmvdc design BACT)	ppmvdc	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***	***3.5***
	lb/MMBtu	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***	***0.0079***
	lb/hr	***25.8***	***24.9***	***19.6***	***12.7***	***25.7***	***20.4***	***11.8***	***26.3***	***20.8***	***12.0***	***27.0***	***21.4***	***12.4***	***27.1***	***21.7***	***14.8***
Particulates (GE data)	lb/hr	18.1	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**	**18.1**
	lb/MMBtu	0.0055	**0.0057**	**0.0073**	**0.0112**	**0.0056**	**0.0070**	**0.0122**	**0.0054**	**0.0069**	**0.0120**	**0.0053**	**0.0067**	**0.0115**	**0.0053**	**0.0066**	**0.0097**
SO2	lb/MMBtu	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
	lb/hr	4.91	4.73	3.73	2.41	4.88	3.87	2.23	4.99	3.94	2.27	5.12	4.07	2.36	5.14	4.11	2.80
VOC (ppmvdc design BACT)	ppmvdc	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MMBtu	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026	0.0026
	lb/hr	8.51	8.19	6.46	4.18	8.46	6.71	3.87	8.64	6.83	3.93	8.88	7.06	4.09	8.90	7.13	4.86
Exhaust Velocity*	feet/sec	135.93	132.93	108.82	80.98	131.14	108.35	75.30	132.28	108.93	75.59	130.94	108.72	76.33	128.29	107.94	84.38
Exhaust Temp *	deg F	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750

*Note : Exhaust temperature and velocity incorporate a temperature loss in the stack of 150 deg F from the attemperated SCR temp of 900 deg F based on Babcock & Wilcox *Steam.*

Updated information for Supplement No. 1 is shown in boldface and italics

Appendix B, Table B-2
Combustion Turbine Exhaust Data for GE7HA.02
ULSD Firing

OPERATING POINT		17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired
SITE CONDITIONS																	
Ambient Temperature	°F	90	90	90	90	59	59	59	50	50	50	20	20	20	0	0	0
Ambient Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Relative Humidity	%	56	56	56	56	60	60	60	60	60	60	66	66	66	40	40	40
Evaporative Cooler state (On or Off)		On	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off	Off
Gas Turbine Load	%	BASE	BASE	75%	37.5%	BASE	75%	30%	BASE	75%	30%	BASE	75%	30%	BASE	75%	40%
GT Diluent Injection Type		Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water	Water
GT Diluent Injection Flow (per GT)	10^3 lb/hr	220.9	220.8	152.4	101.7	230.4	163.5	114.8	236	167	119.3	234.1	171.3	125.8	232.3	172.8	119.8
Fuel Type		DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO	DO
HHV	BTU/lb	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581	19581
LHV	BTU/lb	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300	18300
Fuel Mol. Wt.	lb/mole	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138	138
Fuel Bound Nitrogen	Wt %	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%	≤ 0.015%
Fuel Sulfur Content	ppmw	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
GT Heat Consumption (HHV Basis)	MMBTU/hr	3293	3202	2519	1543	3303	2615	1427	3371	2660	1455	3447	2748	1515	3471	2782	1770
Attemperated Flue Gas Temperature	°F	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Attemperated Flue Gas Flow	ft3/sec	70,682	69,528	57,868	44,211	68,439	57,479	41,157	69,012	57,677	41,438	68,231	57,700	41,773	67,721	57,617	45,197

Stack Emissions

NOx (ppmvdc design BACT)	ppmvdc	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MMBtu	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194	0.0194
	lb/hr	63.89	62.11	48.87	29.93	64.08	50.72	27.68	65.40	51.61	28.23	66.86	53.30	29.39	67.35	53.96	34.34
CO (ppmvdc design BACT)	ppmvdc	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
	lb/MMBtu	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118	0.0118
	lb/hr	38.86	37.78	29.72	18.21	38.97	30.85	16.84	39.78	31.39	17.17	40.67	32.42	17.88	40.96	32.82	20.89
Particulates (GE data)	lb/hr	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8	65.8
	lb/MMBtu	0.0200	0.0205	0.0261	0.0426	0.0199	0.0252	0.0461	0.0195	0.0247	0.0452	0.0191	0.0239	0.0434	0.0190	0.0237	0.0372
SO2	lb/MMBtu	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015	0.0015
	lb/hr	4.94	4.80	3.78	2.31	4.95	3.92	2.14	5.06	3.99	2.18	5.17	4.12	2.27	5.21	4.17	2.66
VOC (ppmvdc design BACT)	ppmvdc	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
	lb/MMBtu	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
	lb/hr	8.89	8.64	6.80	4.17	8.92	7.06	3.85	9.10	7.18	3.93	9.31	7.42	4.09	9.37	7.51	4.78
Exhaust Velocity*	feet/sec	128.11	126.02	104.88	80.13	124.04	104.18	74.59	125.08	104.54	75.10	123.66	104.58	75.71	122.74	104.43	81.92
Exhaust Temp *	deg F	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750

*Note : Exhaust temperature and velocity incorporate a temperature loss in the stack of 150 deg F from the attemperated SCR temp of 900 deg F based on Babcock & Wilcox *Steam.*

Appendix B, Table B-3
Emergency Diesel Generator Data

Emergency Diesel Generator							
Permitting Design based on Caterpillar Tier 4 Alternate FEL C-15 ATAAC engine-generator set							
Engine mechanical power output			779	bhp			
Engine mechanical kW			581	kWm			
Engine Heat Input rating			5.03	MMBtu/hr			
SO2 is based on ULSD							
		Tier 4	Tier 4		**Full load**		
		1039.101	1039.104				
		Table 1	Table 1				
		g/kWhr	g/kWhr		**lb/hr**		
NOx			3.5		**4.48**		
CO		3.5			**4.48**		
PM Part 1039			0.10		**0.13**		
PM with condensables			0.132		**0.17**		
SO2 (lb/MMBtu)		0.0015			**0.0075**		
VOC		0.19			**0.24**		
Exhaust Parameters per Caterpillar Spec Sheet flow & temp							
Flow (acfm)	3842.2						
Temperature (F)	942.1						
Stack Diameter		9	inches				
Stack Height		25	feet				
Exit Temp with temp loss		887.1	F				
Velocity with temp loss		139.3	fps				

Appendix B, Table B-4
Emergency Diesel Fire Pump Data

Emergency Fire Pump					
Permitting Design based on Jon Deere/Clarke JU4H-UFAD5G (135 bhp)					
Maximum engine mechanical kW			101	kWm	
Engine Heat Input rating			1.20	MMBtu/hr	
SO2 is based on ULSD					
		Tier 3			**Full load**
		g/kWhr			**lb/hr**
NOx		4.0			**0.89**
CO		5.0			**1.113**
PM Subpart IIII		0.3			**0.067**
PM with condensables		0.332			**0.074**
SO2 (lb/MMBtu)	0.0015				**0.0018**
VOC		1.3			**0.29**
Exhaust Parameters per Clarke Spec Sheet flow & temp					
Flow (acfm)	694				
Temperature (F)	864				
Stack Diameter		4	inches		
Stack Height		25	feet		
Exit Temp with temp loss		809	F		
Velocity with temp loss		127.0	fps		

Appendix B, Table B-5 - Canal Unit 3 Project Potential Emissions

	Combustion Turbine at 100% Load		Combustion Turbine Starts			Turbine Emissions (tons/year)	Ancillary Sources (tons per year)	Total Canal 3 Project Emissions (tons per year)	Major Modification Threshold (tons/year)	Threshold Type	Major Modification? (Yes/No)
	50 deg F	0 deg F									
	Gas	ULSD		Gas	ULSD						
Hours per year	3660	720	Number of SUSD cycles per year	180	80						
MMBtu/hr	3323	3471									
NOx	0.0092	0.0194	lbs/SUSD cycle	158	227	103.5	0.8	**104.3**	25/40	NNSR/PSD	Yes
CO	***0.0079***	0.0118	lbs/SUSD cycle	263	188	***94.0***	0.8	***94.8***	100	:PSD	***No***
VOC	0.0026	0.0027	lbs/SUSD cycle	34	15	23.3	0.08	***24.4***	25	NNSR	No
SO2	0.0015	0.0015	lbs/SUSD cycle	0.46	0.42	11.1	1.40E-03	**11.1**	40	PSD	No
PM/PM-10	18.1 lb/hr	***65.8 lb/hr***	lbs/SUSD cycle	13.3	61	***60.4***	0.04	***60.5***	25/15	PSD	Yes
PM-2.5	18.1 lb/hr	***65.8 lb/hr***	lbs/SUSD cycle	13.3	61	***60.4***	0.04	***60.5***	10	PSD	Yes
NH3	0.0068	0.0072	lbs/SUSD cycle	--	--	50.3	--	**50.3**	--	--	
H2SO4	0.0016	0.0018	lbs/SUSD cycle	0.49	0.50	12.0	1.1E-04	**12.0**	7	PSD	Yes
Pb	0.00E+00	3.13E-06	lbs/SUSD cycle	0.00E+00	8.73E-04	0.004	3E-06	**0.004**	0.6	PSD	No
Formaldehyde	0.00022	0.00023	lbs/SUSD cycle	0.07	0.06	1.6	2.7E-04	**1.6**	Canal Station is already a Major HAP Source		
CO2e	119.0	162.85	lbs/SUSD cycle	36,418	45,435	932325	152	***934,041***	75,000	PSD	Yes

Notes:
1. Turbine PTE is based on design emission rates in lb/MMBtu as shown except for particulates.
2. PM/PM-10/PM-2.5 emissions are based on the maximum GE lb/hr case for each fuel.
3. Annual emissions for steady-state conditions are based on the 100% load natural gas firing rate or emissions at 50 deg F (3660 hours) and the 100% load ULSD firing rate or emissions at 0 deg F (720 hours) (see also notes 4 & 5).
4. Startup/shutdown (SUSD) cycles are included on top of the steady-state emissions based on GE SUSD emission data and the number of SUSD cycles on each fuel as shown.
5. For CO, VOC and SO2, which have higher SUSD cycle emissions on gas compared to ULSD, the annual emission are based on the maximum of 4380 hours on gas and 260 SUSD cycles on gas, or the approach described in notes 4 & 5.

6. Total Canal VOC emissions includes 1.0 tpy VOC emissions from ULSD working and breathing losses (see pages B-15 through B-28).

7. Total Canal GHG Project Emissions includes allowance for 1,561 tpy CO2e from methane leaks and 3 tpy CO2e from potential SF6 leaks (see page B-29).

8. Updates for Supplement No. 1 in bold/italics

9. Updates for Supplement No. 2 highlighted

Table B-6
HAP Emissions
Combustion Turbine

	Units	Dual Fuel	Gas Only	
50 deg F Base Load Heat Input (Gas)	MMBtu/hr, HHV	3323	3323	
0 deg F Base Load Heat Input (ULSD)	MMBtu/hr, HHV	3471		
Annual Operation	Hours on Gas	3660	4380	
Annual Operation	Hours on Oil	720		
SUSD Gas	MMBtu	306	306	
SUSD ULSD	MMBtu	279		
SUSD Gas	Number per year	180	260	
SUSD ULSD	Number per year	80		

HAP Emissions - Turbine

	Turbine Factor (Gas)	**Turbine Factor (Oil)**	**All Gas HAP Annual**	**Gas/Oil HAP Annual**
Air Toxic	**lb/MMBtu**	**lb/MMBtu**	**tons/yr**	**tons/yr**
1,3 Butadiene	4.30E-07	1.60E-05	3.15E-03	2.28E-02
Acetaldehyde	4.00E-05		2.93E-01	2.44E-01
Acrolein	6.40E-06		4.68E-02	3.91E-02
Benzene	1.20E-05	5.50E-05	8.78E-02	1.43E-01
Ethylbenzene	3.20E-05		2.34E-01	1.95E-01
Formaldehyde	2.20E-04	2.30E-04	1.61E+00	1.63E+00
Naphthalene	1.30E-06	3.50E-05	9.51E-03	5.21E-02
PAH	2.20E-06	4.00E-05	1.61E-02	6.39E-02
Propylene Oxide	2.90E-05		2.12E-01	1.77E-01
Toluene	1.30E-04		9.51E-01	7.94E-01
Xylenes	6.40E-05		4.68E-01	3.91E-01
Arsenic		4.62E-08		5.82E-05
Cadmium		5.13E-09		6.47E-06
Chromium		1.24E-05		1.57E-02
Lead		7.69E-07		9.70E-04
Manganese		2.82E-07		3.56E-04
Mercury		1.03E-08		1.29E-05
Nickel		1.48E-06		1.87E-03
Selenium		2.56E-07		3.23E-04

Total HAP	5.37E-04	3.91E-04	3.93	3.78

Table B-7 Emergency Diesel Generator HAP Emissions

	Units	
Engine Size	kW (mechanical)	581
Maximum Heat Input	MMBtu/hr	5.03
Number of Engines		1
Annual Hours of Operation		300

Emissions Emergency Generator

			HAP
Air Toxic	**lb/MMBtu**	**lb/hr**	**ton/yr**
1,3 Butadiene			
Acetaldehyde	2.52E-05	1.27E-04	1.90E-05
Acrolein	7.88E-06	3.96E-05	5.95E-06
Anthracene	1.23E-06	6.19E-06	9.28E-07
Benzene	7.76E-04	3.90E-03	5.85E-04
Benzo(a)anthracene	6.22E-07	3.13E-06	4.69E-07
Benzo(a)pyrene	2.57E-07	1.29E-06	1.94E-07
Formaldehyde	7.89E-05	3.97E-04	5.95E-05
Naphthalene	1.30E-04	6.54E-04	9.81E-05
PAH	2.12E-04	1.07E-03	1.60E-04
Toluene	2.81E-04	1.41E-03	2.12E-04
Xylene (Total)	1.93E-04	9.71E-04	1.46E-04
Arsenic	4.62E-08	2.32E-07	3.49E-08
Cadmium	5.13E-09	2.58E-08	3.87E-09
Chromium	1.24E-05	6.24E-05	9.36E-06
Lead	7.69E-07	3.87E-06	5.80E-07
Manganese	2.82E-07	1.42E-06	2.13E-07
Mercury	1.03E-08	5.18E-08	7.77E-09
Nickel	1.48E-06	7.44E-06	1.12E-06
Selenium	2.56E-07	1.29E-06	1.93E-07

Total HAPs		5.19E-03	1.30E-03

Table B-8 Emergency Diesel Fire Pump HAP Emissions

	Units	
Engine Size	Horsepower	135
Maximum Heat Input	MMBtu/hr	1.20
Number of Engines		1
Annual Hours of Operation		300

Emissions Emergency Diesel Fire Pump

			HAP
Air Toxic	**lb/MMBtu**	**lb/hr**	**ton/yr**
1,3 Butadiene	3.91E-05	4.69E-05	7.04E-06
Acetaldehyde	7.67E-04	9.20E-04	1.38E-04
Acrolein	9.25E-05	1.11E-04	1.67E-05
Anthracene	1.87E-06	2.24E-06	3.37E-07
Benzene	9.33E-04	1.12E-03	1.68E-04
Benzo(a)anthracene	1.68E-06	2.02E-06	3.02E-07
Benzo(a)pyrene	1.88E-07	2.26E-07	3.38E-08
Formaldehyde	1.18E-03	1.42E-03	2.12E-04
Naphthalene	8.48E-05	1.02E-04	1.53E-05
PAH	1.68E-04	2.02E-04	3.02E-05
Toluene	4.09E-04	4.91E-04	7.36E-05
Xylene (Total)	2.85E-04	3.42E-04	5.13E-05
Arsenic	4.62E-08	5.54E-08	8.32E-09
Cadmium	5.13E-09	6.16E-09	9.23E-10
Chromium	1.24E-05	1.49E-05	2.23E-06
Lead	7.69E-07	9.23E-07	1.38E-07
Manganese	2.82E-07	3.38E-07	5.08E-08
Mercury	1.03E-08	1.24E-08	1.85E-09
Nickel	1.48E-06	1.78E-06	2.66E-07
Selenium	2.56E-07	3.07E-07	4.61E-08

Total HAP		2.86E-03	7.16E-04

TABLE B-9 500 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION -

BACT Assessment
Control System Life: **10 years**
Interest Rate: **10.00%**
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) **0.163**

Baseline NOx Emissions per 40 CFR 1039.104(g) (tpy) **0.67**
SCR Control Efficiency (%) **90%**

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estimate (Per Milton Cat)		$100,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$5,000
Total Equipment Cost (TEC)			**$105,000**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$8,400
b.	Erection and Handling	(TEC*0.14)	$14,700
c.	Electrical	(TEC*0.04)	$4,200
d.	Piping	(TEC*0.02)	$2,100
e.	Insulation	(TEC*0.01)	$1,050
f.	Painting	(TEC*0.01)	$1,050
Total Direct Installation Cost			**$31,500**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$10,500
b.	Construction/Field Expenses	(TEC*0.05)	$5,250
c.	Construction Fee	(TEC*0.1)	$10,500
d.	Start up	(TEC*0.02)	$2,100
e.	Performance Test	(TEC*0.01)	$1,050
Total Indirect Installation Cost			**$29,400**
Total Capital Cost (TCC)			**$165,900**

Capital Recovery		**$27,042**
Direct Operating Costs		
a.	Ammonia	$868
b	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$480
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$480
d	Maintenance Materials = Maintenance Labor	$480
Total Direct Operating Cost		**$2,308**

Catalyst Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year

Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$576
b.	Property Tax: (TCC*0.01)	$1,659
c.	Insurance: (TCC*0.01)	$1,659
d.	Administration: (TCC*0.02)	$3,318
Total Indirect Operating Cost		**$7,212**

Total Annual Cost	**$36,562**
NOx Reduction (tons/yr)	**0.60**
Cost of Control ($/ton - NOx)	**$60,634**

Note 1: SCR capital cost scaled from estimate for 750 kW emergency generator unit.

Note 2: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

TABLE B-10 500 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - CO OXIDATION CATALYST

BACT Assessment
Control System Life: **10 years**
Interest Rate: **10.00%**
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) **0.163**

Baseline CO Emissions per 40 CFR 1039.101 (tpy) **0.67**
Control Efficiency (%) **90%**

Equipment Cost (EC)		(Factor)	
a.	Capital Cost Estimate (per Milton Cat)		$10,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$500
Total Equipment Cost (TEC)			**$10,500**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$840
b.	Erection and Handling	(TEC*0.14)	$1,470
c.	Electrical	(TEC*0.04)	$420
d.	Piping	(TEC*0.02)	$210
e.	Insulation	(TEC*0.01)	$105
f.	Painting	(TEC*0.01)	$105
Total Direct Installation Cost			**$3,150**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$1,050
b.	Construction/Field Expenses	(TEC*0.05)	$525
c.	Construction Fee	(TEC*0.1)	$1,050
d.	Start up	(TEC*0.02)	$210
e.	Performance Test	(TEC*0.01)	$105
Total Indirect Installation Cost			**$2,940**
Total Capital Cost (TCC)			**$16,590**

Capital Recovery		**$2,704**
Direct Operating Costs		
a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c.	Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost		**$720**
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$288
b.	Property Tax: (TCC*0.01)	$166
c.	Insurance: (TCC*0.01)	$166
d.	Administration: (TCC*0.02)	$332
Total Indirect Operating Cost		**$952**
Total Annual Cost		**$4,376**
CO Reduction (tons/yr)		**0.60**
Cost of Control ($/ton - CO)		**$7,257**

Catalyst Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year

Note 1: CO oxidation catalyst capital cost scaled from estimate for 750 kW emergency generator unit.

TABLE B-11 500 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - ACTIVE DIESEL PARTICULATE FILTER

BACT Assessment
Control System Life: **10 years**
Interest Rate: **10.00%**
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) **0.163**

Baseline PM Emissions (includes condensables, tpy) **0.03**
DPF Control Efficiency (%) **85%**

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estimate (per Milton Cat)		$60,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$3,000
Total Equipment Cost (TEC)			**$63,000**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$5,040
b.	Erection and Handling	(TEC*0.14)	$8,820
c.	Electrical	(TEC*0.04)	$2,520
d.	Piping	(TEC*0.02)	$1,260
e.	Insulation	(TEC*0.01)	$630
f.	Painting	(TEC*0.01)	$630
Total Direct Installation Cost			**$18,900**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$6,300
b.	Construction/Field Expenses	(TEC*0.05)	$3,150
c.	Construction Fee	(TEC*0.1)	$6,300
d.	Start up	(TEC*0.02)	$1,260
e.	Performance Test	(TEC*0.01)	$630
Total Indirect Installation Cost			**$17,640**
Total Capital Cost (TCC)			**$99,540**

Capital Recovery		**$16,225**
Direct Operating Costs		
a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c.	Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost		**$720**

DPF Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year

Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$288
b.	Property Tax: (TCC*0.01)	$995
c.	Insurance: (TCC*0.01)	$995
d.	Administration: (TCC*0.02)	$1,991
Total Indirect Operating Cost		**$4,269**

Total Annual Cost	**$21,214**
PM Reduction (tons/yr)	**0.0216**
Cost of Control ($/ton - PM)	**$984,110**

Note 1: DPF capital cost scaled from estimate for 750 kW emergency generator unit.

TABLE B-12 101 kWm EMERGENCY FIRE PUMP
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION -

BACT Assessment
Control System Life: **10 years**
Interest Rate: **10.00%**
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) **0.163**

Baseline NOx Emissions per 40 CFR 60 Subpart IIII (tpy) **0.13**
SCR Control Efficiency (%) **90%**

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estmate (per Milton Cat)		$30,930
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$1,546
Total Equipment Cost (TEC)			**$32,476**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$2,598
b.	Erection and Handling	(TEC*0.14)	$4,547
c.	Electrical	(TEC*0.04)	$1,299
d.	Piping	(TEC*0.02)	$650
e.	Insulation	(TEC*0.01)	$325
f.	Painting	(TEC*0.01)	$325
Total Direct Installation Cost			**$9,743**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$3,247.64
b.	Construction/Field Expenses	(TEC*0.05)	$1,624
c.	Construction Fee	(TEC*0.1)	$3,248
d.	Start up	(TEC*0.02)	$650
e.	Performance Test	(TEC*0.01)	$325
Total Indirect Installation Cost			**$9,093**
Total Capital Cost (TCC)			**$51,313**

Capital Recovery		**$8,364**
Direct Operating Costs		
a.	Ammonia	$168
b	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$480
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$480
d	Maintenance Materials = Maintenance Labor	$480
Total Direct Operating Cost		**$1,608**

Catalyst Replacement is not included since the emergency fire pump will only operate a maximum of 300 hours in any year

Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$576
b.	Property Tax: (TCC*0.01)	$513
c.	Insurance: (TCC*0.01)	$513
d.	Administration: (TCC*0.02)	$1,026
Total Indirect Operating Cost		**$2,628**
Total Annual Cost		**$12,601**
NOx Reduction (tons/yr)		**0.12**
Cost of Control ($/ton - NOx)		**$107,697**

Note 1: SCR capital cost scaled from estimate for 371 emergency diesle fire pump.

Note 2: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

TABLE B-13 101 kWm EMERGENCY DIESEL FIRE PUMP
ECONOMIC ANALYSIS - CO OXIDATION CATALYST

BACT Assessment
Control System Life: **10 years**
Interest Rate: **10.00%**
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) **0.163**

Baseline CO Emissions per 40 CFR 60 Subpart IIII (tpy) **0.17**
Control Efficiency (%) **90%**

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estmate		$2,729
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$136
Total Equipment Cost (TEC)			**$2,866**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$229
b.	Erection and Handling	(TEC*0.14)	$401
c.	Electrical	(TEC*0.04)	$115
d.	Piping	(TEC*0.02)	$57
e.	Insulation	(TEC*0.01)	$29
f.	Painting	(TEC*0.01)	$29
Total Direct Installation Cost			**$860**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$286.56
b.	Construction/Field Expenses	(TEC*0.05)	$143
c.	Construction Fee	(TEC*0.1)	$287
d.	Start up	(TEC*0.02)	$57
e.	Performance Test	(TEC*0.01)	$29
Total Indirect Installation Cost			**$802**
Total Capital Cost (TCC)			**$4,528**

Capital Recovery		**$738**
Direct Operating Costs		
a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c.	Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost		**$720**
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$288
b.	Property Tax: (TCC*0.01)	$45
c.	Insurance: (TCC*0.01)	$45
d.	Administration: (TCC*0.02)	$91
Total Indirect Operating Cost		**$469**
Total Annual Cost		**$1,927**
CO Reduction (tons/yr)		**0.15**
Cost of Control ($/ton - CO)		**$12,597**

Catalyst Replacement is not included since the emergency fire pump will only operate a maximum of 300 hours in any year

Note 1: CO oxidation catalyst capital cost scaled from an estimate for a 371 hp emergency diesel fire pump

TABLE B-14 101 kWm EMERGENCY DIESEL FIRE PUMP
ECONOMIC ANALYSIS - ACTIVE DIESEL PARTICULATE FILTER

BACT Assessment
Control System Life: **10 years**
Interest Rate: **10.00%**
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) **0.163**

Baseline PM Emissions (includes condensables, tpy) **0.011**
DPF Control Efficiency (%) **85%**

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estmate		$16,375
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$819
Total Equipment Cost (TEC)			**$17,193**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$1,375
b.	Erection and Handling	(TEC*0.14)	$2,407
c.	Electrical	(TEC*0.04)	$688
d.	Piping	(TEC*0.02)	$344
e.	Insulation	(TEC*0.01)	$172
f.	Painting	(TEC*0.01)	$172
Total Direct Installation Cost			**$5,158**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$1,719.34
b.	Construction/Field Expenses	(TEC*0.05)	$860
c.	Construction Fee	(TEC*0.1)	$1,719
d.	Start up	(TEC*0.02)	$344
e.	Performance Test	(TEC*0.01)	$172
Total Indirect Installation Cost			**$4,814**
Total Capital Cost (TCC)			**$27,166**

Capital Recovery		**$4,428**
Direct Operating Costs		
a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c.	Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost		**$720**
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$288
b.	Property Tax: (TCC*0.01)	$272
c.	Insurance: (TCC*0.01)	$272
d.	Administration: (TCC*0.02)	$543
Total Indirect Operating Cost		**$1,375**
Total Annual Cost		**$6,523**
PM Reduction (tons/yr)		**0.0094**
Cost of Control ($/ton - PM)		**$697,610**

DPF Replacement is not included since the emergency fire pump will only operate a maximum of 300 hours in any year

Table B-15

	ULSD Storage VOC Working and Breathing Losses		
	ULSD Throughput		
	Rolling 12-month Throughput 720 hours at 3471 MMBtu/hr		
=	(720 hours)(3471 MMBtu/hr)(1,000,000 Btu/MMBtu)/{(19,581 Btu/lb)(7 lb/gal)}		
=	18,232,835	gallons	
	round up to 18,240,000 gallons rolling 12-month throughput		
	Tanks		
	Main Storage Tank (Facility Designation ESCO-1)		
	5.88 million vertical fixed roof tank per Table B-16 Tanks Output		
	All ULSD is delivered into the 5.88 MMgal tank and then transferred into the		
	day tank prior to combustion.		
	Day Tank (Facility Designation FDT1)		
	1.8 million vertical fixed roof tank per Table B-17 Tanks Output		
	All ULSD transferred from the 5.88 MMgal tank passes through the		
	day tank prior to combustion.		
	Summary of Total VOC Working and Breathing Losses		
			VOC (lb/year)
	Main Storage Tank (Table B-16, Sheet 6 of 7)		1310.41
	Day Tank (Table B-17, Sheet 6 of 7)		676.23
		Total (lbs/year)	1986.64
		Total (tons/year)	1.0

TABLE B-16

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	ESCO-1	
City:	Sandwich	
State:	Massachusetts	
Company:	Canal Generating	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	5.88 MM gallon No.2 fuel oil tank	
Tank Dimensions		
Shell Height (ft):		65.00
Diameter (ft):		136.00
Liquid Height (ft) :		52.50
Avg. Liquid Height (ft):		45.50
Volume (gallons):		5,705,059.76
Turnovers:		3.20
Net Throughput(gal/yr):		18,240,000.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Light	
Shell Condition	Good	
Roof Color/Shade:	Gray/Light	
Roof Condition:	Good	
Roof Characteristics		
Type:	Cone	
Height (ft)		4.25
Slope (ft/ft) (Cone Roof)		0.06
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Providence, Rhode Island (Avg Atmospheric Pressure = 14.7 psia)

TABLE B-16

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

ESCO-1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	44.28	38.87	49.69	52.63	0.0037	0.0031	0.0045	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Feb	46.15	39.78	52.51	52.63	0.0040	0.0031	0.0050	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Mar	50.99	43.41	58.56	52.63	0.0047	0.0036	0.0062	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Apr	56.67	47.56	65.78	52.63	0.0058	0.0042	0.0079	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	May	62.20	51.94	72.46	52.63	0.0070	0.0049	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jun	67.02	56.20	77.85	52.63	0.0083	0.0057	0.0114	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jul	69.42	58.95	79.89	52.63	0.0089	0.0063	0.0120	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Aug	67.92	58.27	77.57	52.63	0.0085	0.0062	0.0113	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Sep	63.37	54.62	72.13	52.63	0.0073	0.0054	0.0096	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Oct	57.20	49.71	64.68	52.63	0.0059	0.0045	0.0077	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Nov	51.44	45.85	57.02	52.63	0.0048	0.0039	0.0059	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Dec	46.02	41.12	50.92	52.63	0.0039	0.0033	0.0047	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045

TABLE B-16

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

ESCO-1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	32.4962	37.2690	57.8992	82.7669	114.5091	134.6700	142.6834	126.1480	97.1184	70.4200	40.9204	30.8042
Vapor Space Volume (cu ft):	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9922	0.9909	0.9903	0.9907	0.9919	0.9935	0.9947	0.9956
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523	303,850.6523
Tank Diameter (ft):	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000
Vapor Space Outage (ft):	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167
Tank Shell Height (ft):	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000	65.0000
Average Liquid Height (ft):	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000	45.5000
Roof Outage (ft):	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167
Roof Outage (Cone Roof)												
Roof Outage (ft):	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167	1.4167
Roof Height (ft):	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500	4.2500
Roof Slope (ft/ft):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Shell Radius (ft):	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000
Vapor Density												
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Daily Avg. Liquid Surface Temp. (deg. R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Average Ambient Temp. (deg. F):	27.8500	29.6000	37.4500	47.3500	57.3000	66.8500	72.6500	71.3000	64.0500	53.5500	43.9500	32.8000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017
Tank Paint Solar Absorptance (Shell):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	598.0540	855.3599	1,180.5617	1,491.4863	1,761.1658	1,906.7927	1,869.6721	1,657.7358	1,339.8312	975.2880	615.8211	496.2103
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Daily Vapor Temperature Range (deg. R):	21.6426	25.4610	30.3061	36.4473	41.0288	43.3027	41.8774	38.6010	35.0182	29.9384	22.3432	19.5987
Daily Vapor Pressure Range (psia):	0.0014	0.0019	0.0026	0.0038	0.0048	0.0056	0.0057	0.0051	0.0042	0.0032	0.0020	0.0014
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031	0.0031	0.0036	0.0042	0.0049	0.0057	0.0063	0.0062	0.0054	0.0045	0.0039	0.0033
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0045	0.0050	0.0062	0.0079	0.0097	0.0114	0.0120	0.0113	0.0096	0.0077	0.0059	0.0047
Daily Avg. Liquid Surface Temp. (deg R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Min. Liquid Surface Temp. (deg R):	498.5384	499.4514	503.0815	507.2286	511.6117	515.8664	518.6164	517.9374	514.2869	509.3817	505.5230	500.7929
Daily Max. Liquid Surface Temp. (deg R):	509.3597	512.1820	518.2345	525.4522	532.1261	537.5178	539.5551	537.2379	531.7960	524.3509	516.6946	510.5922
Daily Ambient Temp. Range (deg. R):	17.5000	17.4000	17.3000	19.3000	20.0000	20.1000	18.9000	18.8000	20.5000	21.1000	18.1000	16.8000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9922	0.9909	0.9903	0.9907	0.9919	0.9935	0.9947	0.9956
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Space Outage (ft):	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167	20.9167

TABLE B-16

Working Losses (lb):	17.4032	18.6334	22.1011	27.4480	33.1672	38.8403	41.6557	39.8936	34.5464	27.9428	22.5253	18.5516
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Net Throughput (gal/mo.):	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000
Annual Turnovers:	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972	3.1972
Turnover Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Maximum Liquid Volume (gal):	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576	5,705,059.7576
Maximum Liquid Height (ft):	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000	52.5000
Tank Diameter (ft):	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000	136.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	49.8994	55.9024	80.0003	110.2149	147.6764	173.5103	184.3391	166.0416	131.6649	98.3628	63.4457	49.3558

TABLE B-16

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TABLE B-16

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

ESCO-1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	342.71	967.70	1,310.41

TABLE B-16

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TABLE B-17

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	FDT1	
City:	Sandwich	
State:	Massachusetts	
Company:	Canal Generating	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	1.8 MM gallon fuel oil storage tank	
Tank Dimensions		
Shell Height (ft):		48.00
Diameter (ft):		80.00
Liquid Height (ft) :		48.00
Avg. Liquid Height (ft):		28.00
Volume (gallons):		1,804,863.20
Turnovers:		10.11
Net Throughput(gal/yr):		18,240,000.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Light	
Shell Condition	Good	
Roof Color/Shade:	Gray/Light	
Roof Condition:	Good	
Roof Characteristics		
Type:	Cone	
Height (ft)		2.50
Slope (ft/ft) (Cone Roof)		0.06
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Providence, Rhode Island (Avg Atmospheric Pressure = 14.7 psia)

TABLE B-17

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

FDT1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	Jan	44.28	38.87	49.69	52.63	0.0037	0.0031	0.0045	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Feb	46.15	39.78	52.51	52.63	0.0040	0.0031	0.0050	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045
Distillate fuel oil no. 2	Mar	50.99	43.41	58.56	52.63	0.0047	0.0036	0.0062	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Apr	56.67	47.56	65.78	52.63	0.0058	0.0042	0.0079	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	May	62.20	51.94	72.46	52.63	0.0070	0.0049	0.0097	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jun	67.02	56.20	77.85	52.63	0.0083	0.0057	0.0114	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Jul	69.42	58.95	79.89	52.63	0.0089	0.0063	0.0120	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Aug	67.92	58.27	77.57	52.63	0.0085	0.0062	0.0113	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Sep	63.37	54.62	72.13	52.63	0.0073	0.0054	0.0096	130.0000			188.00	Option 1: VP60 = .0065 VP70 = .009
Distillate fuel oil no. 2	Oct	57.20	49.71	64.68	52.63	0.0059	0.0045	0.0077	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Nov	51.44	45.85	57.02	52.63	0.0048	0.0039	0.0059	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065
Distillate fuel oil no. 2	Dec	46.02	41.12	50.92	52.63	0.0039	0.0033	0.0047	130.0000			188.00	Option 1: VP40 = .0031 VP50 = .0045

TABLE B-17

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

FDT1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	11.1997	12.8447	19.9549	28.5257	39.4659	46.4146	49.1766	43.4775	33.4722	24.2703	14.1032	10.6166
Vapor Space Volume (cu ft):	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9923	0.9910	0.9903	0.9907	0.9920	0.9935	0.9947	0.9957
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550	104,719.7550
Tank Diameter (ft):	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000
Vapor Space Outage (ft):	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333
Tank Shell Height (ft):	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000
Average Liquid Height (ft):	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000	28.0000
Roof Outage (ft):	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333
Roof Outage (Cone Roof)												
Roof Outage (ft):	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333	0.8333
Roof Height (ft):	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000	2.5000
Roof Slope (ft/ft):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Shell Radius (ft):	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000	40.0000
Vapor Density												
Vapor Density (lb/cu ft):	0.0001	0.0001	0.0001	0.0001	0.0002	0.0002	0.0002	0.0002	0.0002	0.0001	0.0001	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Daily Avg. Liquid Surface Temp. (deg. R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Average Ambient Temp. (deg. F):	27.8500	29.6000	37.4500	47.3500	57.3000	66.8500	72.6500	71.3000	64.0500	53.5500	43.9500	32.8000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017	512.3017
Tank Paint Solar Absorptance (Shell):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	598.0540	855.3599	1,180.5617	1,491.4863	1,761.1658	1,906.7927	1,869.6721	1,657.7358	1,339.8312	975.2880	615.8211	496.2103
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.0390	0.0464	0.0554	0.0668	0.0749	0.0785	0.0755	0.0694	0.0632	0.0541	0.0398	0.0348
Daily Vapor Temperature Range (deg. R):	21.6426	25.4610	30.3061	36.4473	41.0288	43.3027	41.8774	38.6010	35.0182	29.9384	22.3432	19.5987
Daily Vapor Pressure Range (psia):	0.0014	0.0019	0.0026	0.0038	0.0048	0.0056	0.0057	0.0051	0.0042	0.0032	0.0020	0.0014
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031	0.0031	0.0036	0.0042	0.0049	0.0057	0.0063	0.0062	0.0054	0.0045	0.0039	0.0033
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0045	0.0050	0.0062	0.0079	0.0097	0.0114	0.0120	0.0113	0.0096	0.0077	0.0059	0.0047
Daily Avg. Liquid Surface Temp. (deg R):	503.9490	505.8167	510.6580	516.3404	521.8689	526.6921	529.0858	527.5876	523.0415	516.8663	511.1088	505.6926
Daily Min. Liquid Surface Temp. (deg R):	498.5384	499.4514	503.0815	507.2286	511.6117	515.8664	518.6164	517.9374	514.2869	509.3817	505.5230	500.7929
Daily Max. Liquid Surface Temp. (deg R):	509.3597	512.1820	518.2345	525.4522	532.1261	537.5178	539.5551	537.2379	531.7960	524.3509	516.6946	510.5922
Daily Ambient Temp. Range (deg. R):	17.5000	17.4000	17.3000	19.3000	20.0000	20.1000	18.9000	18.8000	20.5000	21.1000	18.1000	16.8000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.9959	0.9956	0.9948	0.9936	0.9923	0.9910	0.9903	0.9907	0.9920	0.9935	0.9947	0.9957
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Vapor Space Outage (ft):	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333	20.8333

TABLE B-17

Working Losses (lb):	17.4032	18.6334	22.1011	27.4480	33.1672	38.8403	41.6557	39.8936	34.5464	27.9428	22.5253	18.5516
Vapor Molecular Weight (lb/lb-mole):	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0037	0.0040	0.0047	0.0058	0.0070	0.0083	0.0089	0.0085	0.0073	0.0059	0.0048	0.0039
Net Throughput (gal/mo.):	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000	1,520,000.0000
Annual Turnovers:	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060	10.1060
Turnover Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Maximum Liquid Volume (gal):	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957	1,804,863.1957
Maximum Liquid Height (ft):	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000	48.0000
Tank Diameter (ft):	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000	80.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	28.6029	31.4781	42.0560	55.9737	72.6331	85.2549	90.8323	83.3711	68.0186	52.2131	36.6285	29.1682

TABLE B-17

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TABLE B-17

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

FDT1 - Vertical Fixed Roof Tank
Sandwich, Massachusetts

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	342.71	333.52	676.23

TABLE B-17

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Table B-18 Compressor and Gas Insulated Switchgear Fugitive GHG Emissions

Reciprocating Compressor Fugitive Methane Emissions									
Use Table 3-5 of EPA Report:									
Report for Oil and Natural Gas Sector Compressors, Review Panel, April 2014, USEPA OAQPS									
Apply 50% margin to cover variabiity and other site fugitives, correct to short tons, GWP = 25									
75,809 MT of CH4 for 2008 total number of compressors reported									
GHG as CO2e = (75,809 metric tons of CH4 total)/(2008 compressors)(1.1023 short tons/MT)(25)									
= 1040.4 tons GHG as CO2e)(1.5) =			**1,561**	**tons of GHG as CO2e**					
Sulfur Hexafluoride (SF6) Gas Insulated Switchgear (GIS)									
Design basis for GIS is 25 pounds of SF6 with a maximum annual leakage rate of 1%									
GWP = 22,800									
GHG as CO2e = (25 pounds SF6)(1.0/100)(22,800)/(2000 lb/ton) =						**3**	**tons of GHG as CO2e**		

APPENDIX C: NONATTAINMENT NEW SOURCE REVIEW ALTERNATIVES ANALYSIS

C. 1 INTRODUCTION

Appendix C addresses the requirement for an alternatives analysis corresponding to 310 CMR 7.00: Appendix A(8)(b), which states:

> ***"By means of an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed new or modified stationary source, the owner or operator of the proposed stationary source or modification shall demonstrate to the satisfaction of the Department that the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification."***

Section C.2 describes the Site Selection Process for the Project. Section C.3 address Alternative Project Sizes, Section C.4 address Alternative Production Processes, and Section C.5 addresses Environmental Control Techniques. Section C.6 provides an Evaluation of Project Benefits Compared to Environmental and Social Costs

C.2 SITE SELECTION PROCESS

The objective of the Project is to respond to an identified need for additional peak electric generating resources within the ISO-NE transmission system. With current forecasts by ISO-NE indicating the region is expected to fall short of its reserve margin requirement in 2019, the forward capacity market is seeking generating sources through an auction process that will secure "capacity" three-plus years ahead of the commitment period and allows favorable new units to compete. A new unit, such as the one proposed, would contribute to available reserves, as well as enhancing reliability by providing a flexible source of efficient and clean generation to meet intermittent system needs. ISO-NE has identified the Southeast Massachusetts/Rhode Island (SEMA/RI) subregion as the most constrained. In ISO-NE's Forward Capacity Auction (FCA) #9, the SEMA/RI subregion was the only region with a resource shortfall. As such, sites located in the SEMA/RI subregion were given the highest priority. Further, to ensure that no clearly preferable site was eliminated, and keeping with NRG's sustainability focus and strong desire to utilize the locations of existing facilities for new generation, NRG also considered its existing generating assets in New England as possible sites.

As stated above, NRG's corporate sustainability philosophy led to a focus on previously developed sites that currently are, or formerly had been, within the NRG fleet, as well as other sites that currently host electric generating facilities that NRG had considered for possible expansion as part of its evaluation of those sites in recent divestiture opportunities.

In focusing on such sites, NRG is able to avoid the significant environmental, community, and financial impacts associated with clearing and adapting a "greenfield" site to power generation. In addition, this focus intended to minimize or eliminate the need for new infrastructure to connect the proposed facility to fuel sources and the electric grid. Therefore, the locations to be evaluated as potential sites were intended to have the following characteristics:

- existing development as power facilities, indicating appropriate zoning and community acceptance;
- adequate space for a new facility;
- appropriate fuel source and connectivity to the electric grid; and,
- available water supply to meet pollution control needs associated with ULSD-firing for reliability enhancement.

Consideration of the range of sites available from the NRG fleet, or that NRG had previously evaluated also enhanced knowledge of site characteristics beyond what might ordinarily be known when screening for an initial evaluation of sites, lending further confidence in the ultimate selection of a site that would appropriately balance reliability, minimal environmental impact, and the lowest possible cost. An initial screening of 17 potential candidate sites identified three final candidate locations for more detailed scrutiny, which led to selection of the Sandwich site.

C.1.1 Initial Evaluation of Candidate Sites

NRG considered the general objectives discussed above in its initial evaluation of candidate sites. A total of 12 sites that NRG owned or had recently owned plus five sites that it had evaluated in recent divestiture processes, were initially considered as a location for the project, which were narrowed down to three finalist sites (NRG Energy, Middletown, CT; Brayton Point, Somerset, MA; and Canal Generating Station, Sandwich, MA) that were subjected to more detailed evaluation before selection of the Sandwich site. The candidate sites included:

- Brayton Point, Somerset, MA
- Canal Generating Station, Sandwich, MA
- Connecticut Jet Power Fleet:
    - Cos Cob
    - Branford
    - Torrington (Franklin Drive)
    - Torrington Terminal
- Dartmouth Power, Dartmouth, MA
- Devon Station, Milford, CT
- Dighton Power, Dighton, MA
- Fore River Station, Weymouth, MA
- Middletown Station, Middletown, CT
- Montville Station, Uncasville, CT
- Norwalk Harbor Power Plant, Norwalk, CT
- Oak Bluffs Plant, Martha's Vineyard, MA
- Somerset Power, Somerset, MA
- Tiverton Power, Tiverton, RI
- West Tisbury Generators, Martha's Vineyard, MA

A discussion of the 17 candidate sites and the initial evaluation of each with regard to available space; access to adequate natural gas; electric transmission and water infrastructure; and location within the ISO-NE electrical grid is provided below.

Brayton Point – Somerset, MA – Brayton Point is an approximately 1,528-MW fossil fuel-fired power generating station located in Somerset, Massachusetts, that was divested by Dominion Resources, Inc. in 2013, and subsequently by EquiPower in 2014. The current owner, Dynegy, has indicated that the plant will be shut down in mid-2017, as previously planned by EquiPower.

The Brayton Point facility is located on an approximately 256-acre property, located at the confluence of the Lee and Taunton rivers as they flow into Mount Hope Bay. Mixed residential and commercial properties are located north, east, and west of the property. Brayton Point is bordered by Fox Hill Cove to the northwest, undeveloped land and Interstate 195 (I-195), a major east-west interstate highway to the north; undeveloped upland, tidal marsh, coastal beach and residential development to the east; and the confluence of the Taunton River to the southeast.

Units 1, 2, 3, and 4 commenced commercial operation in 1963, 1964, 1969, and 1974, respectively. Units 1 through 3 burn low-sulfur pulverized coal as the primary fuel, with oil as supplemental fuel and natural gas for ignition. Unit 4 uses low-sulfur oil or natural gas as primary fuels. The most recent construction at the site includes two new 500-foot tall natural draft cooling towers and a scrubber on Unit 3. In general, the southern half of the property consists of the power generation and facility operations, and the northern half of the property consists of the historical and current wastewater treatment system and ash management area.

The following factors were evaluated for this location:

- Available space – Sufficient land for a new unit may necessitate removal of existing structures; however, given the overall size of the property, adequate space for a new unit appears to exist.
- Access to adequate natural gas – The site is served by an existing connection to the Algonquin system, which supports the existing Unit 4.
- Availability of transmission infrastructure and location within the electrical grid – Several electric transmission lines extend to the site, retirement of the existing units will leave considerable transmission take-away capacity.
- Availability of water infrastructure – The existing facility utilizes two closed-cycle natural-draft cooling towers with make-up water drawn from the Taunton River and cooling tower blowdown discharged to Mount Hope Bay. The facility receives non-process potable water from the Town of Somerset as well as gray water for use in the spray dryer absorbers for Units 1 and 2.

The Brayton Point site was determined to be a viable location for a new peak electric generating unit based on the combination of available space, sufficient natural gas supply, availability of water, and adequate electric transmission capacity. For these reasons, this property was carried forward as a final candidate site.

Canal Generating Station – Sandwich, MA – The 88-acre Canal Generating Station site is situated along the Cape Cod Canal. Named for its location on the Cape Cod Canal, the Canal Generating Station first came into operation as a No. 6 fuel oil-fired electric generating station in 1968. Comprised of two electric generation units, each with an approximate nominal generating capacity of 560 MW, the plant was brought online in two phases: Unit 1, a Babcock & Wilcox boiler that fires No. 6 fuel oil as the sole operational fuel, with No. 2 fuel oil as a startup fuel, began commercial operation in July 1968; Unit 2, a Babcock & Wilcox boiler that fires No. 6 fuel oil as the primary fuel, with natural gas as a back fuel, began commercial operation in February 1976. Although both units were originally constructed to run solely on No. 6 fuel oil, Unit 2 was modified in June 1996 to allow firing of either No. 6 fuel oil or natural gas.

The 88-acre site is comprised of two non-contiguous properties. The 52-acre northern area, which is located north of an active railroad corridor owned by Massachusetts Department of Transportation and operated by the Cape Cod Central Railroad, is zoned Industrial and largely occupied by the existing Canal Generating Station. The 36-acre southern area, which is located south of the active railroad corridor, is zoned Business Limited, and mostly undeveloped. Two large aboveground storage tanks supporting the Canal Generating Station are situated on the southern area, and a 345-kV transmission corridor occupies the eastern edge through an easement held by Eversource. The site is bounded to the east by the Sandwich Marina; to the north by Canal Service Road and the Cape Cod Canal; to the west by undeveloped land in the town of Bourne; and to the south by Route 6A, an active railroad corridor, and an electrical switchyard. The site includes fuel oil tanks, aboveground and underground piping, once-through cooling infrastructure, and structures and equipment associated with the existing generating facility.

The following factors were evaluated for this location:

- Available space – Sufficient land appears to be available, including for potential construction laydown use.
- Access to adequate natural gas – Connection to the Algonquin Gas Transmission system currently exists via a distribution line already serving the existing Canal Generating Station.
- Availability of transmission infrastructure and location within the electrical grid – Several electric transmission lines extend to the site, including 115-kV and 345-kV infrastructure.

- Availability of water infrastructure – The facility holds water well registrations and diversion permits for once-through cooling and other purposes. Existing, unused on-site wells are also located on the site as potential water sources.

The Sandwich site was selected for further evaluation based on adequate space, sufficient natural gas supply, availability of water, and proximity to a robust electric interconnection location.

Connecticut Jet Power, CT – The Connecticut Jet Power fleet is comprised of four remote jet stations located within the confines of Eversource substations: Cos Cob, Branford, Torrington (Franklin Drive), and Torrington Terminal. Each is briefly described below:

- Cos Cob – The generating facility was originally constructed by Connecticut Light & Power (CL&P) in 1969 and comprised of three 20-MW units. In June 2008, NRG commissioned two additional 20-MW units increasing capacity to 100 MW of peaking power. The five Pratt & Whitney combustion turbines currently operate on ULSD. The facility is situated on a 0.96-acre site within the existing Eversource 115 kV substation, on land owned by Eversource and is within 1,000 feet of the Cos Cob Harbor in an area zoned as Waterfront Business. Adjacent land uses are an office building to west; town property to the east (the former Cos Cob power plant) that has been converted to a town park and ball fields; a railroad station to the north; and a condominium complex to the south. Water for emissions control is provided by the local utility.
- Branford – The 3.5-acre Branford site is situated along the Branford River on land owned by Eversource. Originally placed in service in 1967, the facility has a nominal aggregate generating capacity of 20 MW and is comprised of a combustion turbine. The property is zoned for Local Business (BL), and is bounded to the north and east by the Branford River; to the south by E Main Street and commercial development; and to the west by multi-family residential development. Further commercial and residential development lie to the south and east, beyond the Branford River, and I-95 lies on the northern bank of the Branford River. The site is gravel-covered and is largely occupied by an existing electrical substation.
- Torrington (Franklin Drive) – The Franklin Drive site is a fully fenced property owned by Eversource located within a substation. The property is zoned Industrial, and is bounded: to the north by the existing CL&P substation structures; to the east by an unnamed stream; to the south by vacant property; and to the west by an industrial development. Extensive residential development lies in all directions further from the site. The single existing unit, a 20-MW combustion turbine, was first placed into service in 1968.
- Torrington Terminal – The 1.2-acre Torrington Terminal site straddles the boundary of Torrington and Litchfield, and is zoned Industrial in both municipalities. The site is owned by Eversource and is located within an existing substation property. A single 20-MW combustion turbine has operated in this location since 1967. The site is bounded to the north by an industrial property; to the south by commercial development; to the west by a rail line and undeveloped land; and to the east by S Main Street. Further east, beyond S Main Street, lies the Naugatuck River and an active quarry owned by O&G Industries Inc. In addition to the combustion turbine, the site is occupied by two aboveground storage tanks, associated structures and equipment, and an electrical switchyard.

The following factors were evaluated for these locations:

- Available space – None of the four locations have sufficient space to accommodate an additional unit.
- Access to adequate natural gas – Existing natural gas pipelines were not identified within 1 mile of any of the four locations.
- Availability of transmission infrastructure and location within the electrical grid – All four sites are located proximate to or within existing substations that provide the opportunity to ready interconnection to the electrical grid.

- Availability of water infrastructure – Municipal water supplies are likely to exist within these communities that could support pollution control; however, most of these sites are not currently served by water utilities.

Because adequate site space and natural gas were not available, the four Connecticut Jet Power sites were eliminated from further consideration.

Dartmouth, MA - The Dartmouth Generation Facility encompasses two non-contiguous pieces of property which total approximately 32 acres of land. The Dartmouth Generation Facility is comprised of one natural gas-fired combined-cycle unit, producing 66 MW, and one natural gas-fired simple cycle peaker, producing 23.4 MW. The main power plant is located on 27 acres and comprised of one GE Frame 6B combustion turbine, one GE LM2500 simple cycle combustion turbine, two auxiliary boilers, a three-cell cooling tower, and other ancillary equipment.

The following factors were evaluated for this location:

- Available space – Sufficient land does not appear to be available for a new unit on land currently controlled by the facility.
- Access to adequate natural gas – The site is adjacent to two major Algonquin lines, which appear to be adequate to support an additional unit at the site.
- Availability of transmission infrastructure and location within the electrical grid – The facility is connected to the ISO-NE grid through two interconnections: a 230-kV connection for the combined-cycle operation and a 115-kV connection for the simple cycle combustion turbine. It is unclear if sufficient take-away capacity would exist to support an additional unit.
- Availability of water infrastructure – Potable and process water are supplied by the Town of North Dartmouth. Sanitary sewer service is provided by the Town of North Dartmouth municipal sanitary sewer system.

It does not appear that sufficient space or electrical take-away capacity exists on this site to warrant further investigation. Therefore, this site was eliminated from consideration.

Devon – Milford, CT – The Devon Station Power Plant site is the location of a former coal-fired electric generating facility first operated at the site in 1924. More recently, generating units on the site have utilized natural gas and oil as fuels. The site is located on property zoned for industrial uses (Housatonic Design District) located adjacent to the Housatonic River and just north of Interstate 95 (I-95) in Milford, CT. The property is generally bounded to the west by the Housatonic River, with residential uses on the opposite shore; to the north by a former oil storage terminal, with waterfront residential condominiums located further north; to the east by Naugatuck Avenue, rail lines, and transmission lines located in a Limited Industrial district, followed by residential neighborhoods; and to the south by I-95.

The last remaining electric steam generating Units 7 and 8 at the Devon site, commissioned in 1956 and 1958, were deactivated in 2004. NRG currently owns and operates four natural gas- and oil-fired 50-MW peak electric generating units that produce electricity only when demand for power is at its highest and one oil-fired 20 MW peaking electric generating unit. The stacks and steelwork on top of the buildings associated with retired units have been removed, but the brick buildings remain in place; the buildings no longer house active generating equipment.

The following factors were evaluated for this location:

- Available space: The property is narrow in configuration, extending along the Housatonic River. Given the long-term use of the site, several areas are dedicated to oil storage and have been used for site closure activities associated with the former operating facility. A significant portion of the site is taken up by the former generating facility structures, which would require demolition and removal in order to site additional facilities in that location. Given an identified minimum size requirement of 10 contiguous acres, sufficient contiguous property did not appear to exist without the need for extensive demolition.

- Access to adequate natural gas – Natural gas interconnection exists at the site to serve the existing eight of the nine peaking units.
- Availability of transmission infrastructure and location within the electrical grid – Significant electric transmission infrastructure exists proximate to this site, with 115-kV transmission lines currently providing interconnection to the existing facility, and a 345-kV transmission line located within about 1,000 feet.
- Availability of water infrastructure – Water is supplied to the local community by a regional water authority that obtains its supply from surface water sources.

With 200 MW of existing capability recently developed in this location owned by GenConn Devon in addition to the units owned by NRG, and the space limitations to accommodate the class of turbine selected for the project, this site was not considered appropriate to carry forward for further consideration.

Dighton, MA - The approximately 170-MW Dighton Power Plant site is located near the confluence of the Segreganset River and the Taunton River in Dighton, Massachusetts. The facility consists of a single combined-cycle combustion turbine unit that was divested by EquiPower in 2014. The facility is now owned by Dynegy.

The main facilities of the Dighton Power Plant are situated on a relatively compact 6-acre portion of the property. Although previously covering approximately 42 acres of land, approximately 3 acres of land was donated to the Dighton Police Department in May of 2013, reducing the site's size to 39 acres. Major structures on the property include the power generation building, an air cooled condenser, a gas compressor building, a wet surface auxiliary condenser, a transformer yard, a 27,000-gallon aqueous ammonia tank, and various auxiliary structures.

The following factors were evaluated for this location:

- Available space: NRG understands that much of the undeveloped portions of the site are subject to conservation easements to preserve open space. Given an identified minimum size requirement of 10 contiguous acres, it is unclear if sufficient buildable acreage exists on the site to support a new unit.
- Access to adequate natural gas – The site is adjacent to an Algonquin Natural Gas Pipeline, which runs east-west across the site, parallel to the southern side of the main facility.
- Availability of transmission infrastructure and location within the electrical grid – Electricity generated by the plant interconnects with National Grid's 115-kV transmission lines located along the western edge of Route 138.
- Availability of water infrastructure – No water supply wells are on-site, as the facility is provided raw water by the Town of Dighton. Sanitary wastewater is discharged to the Town of Dighton's sewer system and conveyed to the City of Taunton's wastewater treatment plant.

The availability of sufficient buildable area on the site is uncertain and the take-away capacity of the existing 115-kV transmission lines is limited. In addition, NRG does not control the site, and combined with the limitations noted above, this site was eliminated from further consideration.

Fore River, Weymouth, MA - The Fore River Generating Station consists of two dual-fuel combined-cycle combustion turbines totaling approximately 700 MW, located in North Weymouth, Massachusetts. The facility is now owned by Calpine. The property consists of two parcels: the north parcel contains approximately 20 acres, and the south parcel contains 58 acres and includes the existing Fore River Generating Station. The north parcel maintains frontage along Bridge Street between Weymouth Fore River in Quincy to the north and King's Cove in Weymouth to the south. The south parcel maintains frontage on Bridge Street to the north and Monatiquot Street to the east.

The majority of the north parcel is upland but it also includes over 15 acres of open watersheet located below mean high water. The eastern portion of the site abutting King's Cove maintains a conservation restriction. The 58-acre south parcel contains approximately 35 acres of upland (above mean high water) and the existing natural gas-fired power plant and supporting infrastructure occupy the majority of the parcel. The parcel abuts the Weymouth Fore River to the west, south and southeast. In addition, an area in the northwest portion of the lot is mapped as a conservation restriction.

The north and south parcels are located entirely within the Fore River Designated Port Area (DPA). Procedures guiding development with DPAs are included within Massachusetts General Law Chapter 91 (Public Waterfront Act) and its associated regulations (310 CMR 9.00). In Designated Port Areas the limit of jurisdiction on filled tidelands is the historic mean high water shoreline. Chapter 91 jurisdiction, or the limit of historic mean high water, occupies the majority of the north parcel and a considerable portion of the south parcel.

The following factors were evaluated for this location:

- Available space: Due to the presence of filled tidelands, the conservation restriction, existing infrastructure and easements, it is unclear if sufficient buildable acreage exists on the site to support a new unit.
- Access to adequate natural gas – The site is bisected by an Algonquin Natural Gas Pipeline, which traverses the south parcel from north to south.
- Availability of transmission infrastructure and location within the electrical grid – Electricity generated by the plant is interconnected with the grid via a 345-kV Eversource transmission line.
- Availability of water infrastructure – The facility obtains water from the City of Weymouth and discharges wastewater to the Massachusetts Water Resources Authority system.

Buildable area on the site appears to be limited and not sufficient for the intended size of the proposed Facility. Further, virtually any development of the site would require Chapter 91 approval. In addition, NRG does not control the site. Based on these limitations this site was eliminated from further consideration.

Middletown, CT – The approximately 60-acre Middletown facility is situated along the Connecticut River. The Middletown facility was originally powered with a series of steam generating turbines and one combustion turbine-fired by oil, natural gas, and jet fuel. The first of these units became operational at the site in the 1950s. In 2011, with several of the existing units remaining in service, 200 MW of nominal generating capacity was commissioned, comprised of four 50-MW aero-derivative gas turbine units. The four GE LM 6000 50-MW combustion turbines are dual-fueled, running on natural gas and jet fuel, and are fast-start “peaking” type units capable of achieving full output within ten minutes of being dispatched. In addition, a Gas Insulated Substation was constructed on site and is owned by Eversource.

A portion of the property is zoned Special Industrial, with the balance of the area zoned as Park-Recreation, reflecting its proximity to the Connecticut River, which abuts the site to the north. The site is bounded to the south and west by a railroad corridor and undeveloped land; and to the east by undeveloped land. The site is comprised of the existing combustion turbines and other equipment associated with the existing power station, including an electrical switchyard and electric transmission lines.

The following factors were evaluated for this location:

- Available space – Although the property has recently been repowered and includes a substantial amount of existing equipment, the identified minimum size requirement of 10 contiguous acres does appear to be available.
- Access to adequate natural gas – Connection to the Algonquin Gas Transmission system currently exists via a pipeline already serving the existing power station.
- Availability of transmission infrastructure and location within the electrical grid – Several electric transmission lines extend to the site, including 115-kV and 345-kV infrastructure.
- Availability of water infrastructure – The facility holds water well registrations and diversion permits for once-through cooling and other purposes.

The Middletown site was determined to be a suitable location for the proposed peaking unit based on the combination of adequate space, sufficient natural gas supply, availability of water, and proximity to an electric interconnection location. For these reasons, this property was carried forward as a final candidate site.

Montville - Uncasville, CT – The 49-acre Uncasville facility is situated along the Thames River. Originally placed in service in the 1950s, the facility has a nominal aggregate generating capacity of 500 MW and is comprised of four units: two steam boilers (Units 5 and 6) and two diesel-fired internal combustion engines (Units 10 and 11). The facility has historically been fueled by natural gas and No. 6 oil. In 2009, NRG obtained Connecticut Siting Council approval to repower Unit 5 to produce up to 40 MW (of its approximately 80 MW total capacity) with renewable energy using clean wood biomass from nearby forester and sawmills; however, the repowering project has subsequently been cancelled.

The site is industrially zoned, and is bounded to the south by wooded open space and scattered residences; to the east by the Thames River; to the north by additional industrial land including the decommissioned AES Thames coal-fired power facility; and to the west by Lathrop Road and a more densely populated residential area. The site is transected by a rail line and includes fuel oil tanks and unloading areas, wastewater treatment facilities, structures and equipment associated with the existing generating facility, and electrical switchyards.

The following factors were evaluated for this location:

- Available space – Given the cancellation of the biomass project, adequate space for a contiguous 10-acre parcel appears to be available.
- Access to adequate natural gas – Connection to the Algonquin Gas Transmission pipeline currently exists via a pipeline spur owned by Yankee Gas Services Company. This interconnection, however, would not provide an adequate supply of natural gas to support the project without substantial system upgrades. No other natural gas supply is readily available to the site.
- Availability of transmission infrastructure and location within the electrical grid – Several electric transmission lines extend to the site, including 115-kV, 138-kV, and 345-kV infrastructure.
- Availability of water infrastructure – The facility holds water well registrations and diversion permits for once through cooling and other purposes.

Although adequate space exists and other attributes could support development at this location, the lack of sufficient natural gas supply would not support the size and type of facility proposed. The Uncasville site was, therefore, eliminated from further consideration.

Norwalk Harbor, CT – The approximately 125-acre Norwalk Harbor Power Plant site is the location of a former coal-fired electric generating facility first operated at the site in 1960. More recently, generating units on the site have utilized oil as fuel. The site is located on Manresa Island, within the Coastal Area Management Boundary, and there is a significant amount of wetlands on the property. Based on the February 2015 Zoning Map for Norwalk, Connecticut, the entire property is zoned for residential development. The site is bounded to the south, east, and west by the Norwalk Harbor, with nearby scattered islands; and to the north by undeveloped, marshy land. Residential development begins beyond the marsh land, along the banks of Village Creek and the mouth of the Norwalk River.

NRG took ownership of the site in 1999. The facility was decommissioned on June 1, 2013. Prior to decommissioning, the facility had a 352-MW generating capacity.

The following factors were evaluated for this location:

- Available space: The property is located on a peninsula that extends into the Norwalk Harbor. Given the long-term use of the site, several areas are dedicated to oil storage and have been used for site closure activities associated with the former operating facility. A significant portion of the site is taken up by the former generating facility structures, which would require demolition and removal in order to site additional facilities in that location. Given an identified minimum size requirement of 10 contiguous acres, sufficient contiguous property did not appear to exist without the need for extensive demolition. In addition, although the long-term use has been for power generation, the site is residentially zoned.

- Access to adequate natural gas – Natural gas is not available at the site, with only local distribution company natural gas in proximity. The closest pipeline with adequate size to serve a facility of the type proposed is located over 6 miles from the site in the Long Island Sound.
- Availability of transmission infrastructure and location within the electrical grid – A 115-kV transmission infrastructure exists in association with the former use of the site.
- Availability of water infrastructure – Water is supplied to the local community by a regional water authority that obtains its supply from surface water sources.

Significant demolition and removal would be required in order to create the required space to accommodate the class of turbine selected for the project. The residential zoning also appears to indicate that future use of the site for power generation is not consistent with local planning efforts. Therefore, this site was not considered appropriate to carry forward for further consideration.

<u>Oak Bluffs - Martha's Vineyard, MA</u> – The Oak Bluffs facility is located on the northern side of Martha's Vineyard on Edgartown-Vineyard Haven Road, Oak Bluffs. The existing units at this site have been in operation since 1969. The site is small in size, and is surrounded by Vineyard Haven Road to the east; sand and gravel mining operations to the south and west; and a trucking facility to the north. Wooded open space generally surrounds the area.

The existing facility consists of three diesel engine electric generator sets, each having a nominal output of 2.5 MW. No. 2 fuel oil is utilized in these peaking facilities, which serve to provide back-up on-island energy.

The following factors were evaluated for this location:

- Available space – No additional space is available on the property currently controlled by NRG Energy.
- Access to adequate natural gas – No natural gas supplies are available in this island location.
- Availability of transmission infrastructure and location within the electrical grid – Although the existing facility is connected to the island infrastructure, the purpose of the Project is to serve load throughout the broader ISO-NE market. The lack of connectivity to the mainland electrical grid does not meet the Project's purpose.
- Availability of water infrastructure – The current facility is served by municipal water.

The lack of land, natural gas, and electric infrastructure eliminated this site from further consideration.

<u>Somerset Power - Somerset, MA</u> – Although no longer owned by NRG, this formerly owned location was considered as a candidate site given its geographic location within ISO-NE. The property was the location of an approximately 130-MW coal- and oil-fired power plant, first operational in 1925. The facility was closed in 2010.

The approximately 38-acre industrially zoned site is located on Breeds Cove, and is bounded by the Taunton River to the east and south; Riverside Avenue to the west (with clusters of residences as well as existing industrial land in the immediate surroundings); and residences to the north. A series of community forums (including during the summer of 2015) have been undertaken through funding with the Massachusetts Clean Energy Center (Somerset Power Plant Reuse Study) to identify possible options for the site (and the nearby site of the Brayton Point facility), looking at a range of issues including zoning, cleanup constraints, coastal and regulatory regulations, and effects on abutters and traffic. Although the ultimate redevelopment decisions will be made by site owners, this robust community engagement process (based on reporting from the June 2015 workshop) indicated a focus on renewable energy (e.g., anaerobic digestion), a strong desire to support diversified tax base, and a consideration for waterfront access and maintaining marine uses in the deep-water port adjacent to the site. Reportedly, 11 acres of the property have been sold to National Grid for use in developing a new electrical substation on Riverside Avenue.

The following factors were evaluated for this location:

- Available space – Although certain land has transferred ownership for new uses, and significant demolition and cleanup would be required in order to utilize the property, sufficient land appears to be available.
- Access to adequate natural gas – Interstate pipeline natural gas is not available at the site. The closest pipeline is located over 1.5 miles from the site and would need to be developed through densely populated areas.
- Availability of transmission infrastructure and location within the electrical grid – Transmission infrastructure exists in association with the former use of the site, but the former facility's size is considerably smaller than the proposed Facility. Therefore, the adequacy of additional take-away capacity is uncertain.
- Availability of water infrastructure – The property is located on the waterfront, with access to surface water, although this source may not be appropriate for a use such as the project. Municipal water is also potentially available.

This site is no longer under the control of NRG Energy. Given the need for demolition and remediation, the lack of on-site pipeline natural gas interconnection, as well as the robust community process currently underway that does not appear to be contemplating uses such as the project, the Somerset site was eliminated as not suitable within a reasonable timeframe.

Tiverton, RI – The approximately 265-MW Tiverton Power plant is located on a 57-acre site in Town of Tiverton, Rhode Island, approximately 0.5 miles south of Route 24. The facility consists of a single natural gas-fired combustion turbine in combined-cycle mode. The facility was divested by Capital Power in 2013 and is now owned by Emera.

The site area is predominantly wooded, but zoned for industrial use. The nearest neighbor, the Tiverton Police Department, is approximately 0.25 miles away.

The following factors were evaluated for this location:

- Available space: Sufficient buildable acreage exists on the site to support a new unit; however, the site is predominantly wooded and significant clearing would be required.
- Access to adequate natural gas – Natural gas for Tiverton is delivered to the facility directly from Spectra Energy's Algonquin Gas Transmission System.
- Availability of transmission infrastructure and location within the electrical grid – The facility is interconnected to the National Grid through an on-site 115 kV substation. Additional take-away capacity may be limited.
- Availability of water infrastructure – The facility obtains water from the Town of Tiverton. Sanitary wastewater is treated on-site through the use of a septic tank with an on-site leaching field. Process wastewater is treated in a zero-liquid discharge system; recycled water is returned to the raw water storage tank for reuse. Dry solids from the system are disposed of as non-hazardous waste at a local landfill.

While sufficient buildable area on the site does appear to be available, development on the available acreage would require significant clearing of forested area. In addition, adequate additional take-away capacity on the existing 115-kV transmission system may be limited. Since NRG does not control the site, and in combination with the limitations noted above, this site was eliminated from further consideration.

West Tisbury Generators - Martha's Vineyard, MA – The West Tisbury facility is centrally located on the island, just west of the airport on Fire Lane No. 5, West Side, West Tisbury. The existing units at this site have been in operation since 1975. The site is small in size, surrounded by forested land.

The existing facility consists of two diesel engine electric generator sets, each having a nominal output of 2.5 MW. No. 2 fuel oil is utilized in these peaking facilities, which serve to provide back-up on-island energy.

The following factors were evaluated for this location:

- Available space – No additional space is available on the property currently controlled by NRG.
- Access to adequate natural gas – No natural gas supplies are available in this island location.
- Availability of transmission infrastructure and location within the electrical grid – Although the existing facility is connected to the island infrastructure, the purpose of the Project is to serve load throughout the broader ISO-NE market. The lack of connectivity to the mainland electrical grid does not meet the Project's purpose.
- Availability of water infrastructure – The current facility is served by municipal water.

The lack of land, natural gas, and electric infrastructure eliminated this site from further consideration.

C.1.2 Criteria for Evaluation of Final Candidate Sites

After eliminating the Connecticut Jet Power, Dartmouth, Devon, Dighton, Fore River, Montville, Norwalk Harbor, Oak Bluffs, Somerset, Tiverton, and West Tisbury sites, NRG evaluated the three remaining sites – Brayton Point, Canal, and Middletown – applying the locational, environmental, and community criteria described below.

Locational Considerations

NRG employed the following locational considerations as part of its process of selecting its sites:

- Sufficient readily buildable acreage. NRG considered only those sites with a minimum of 10 acres available for the proposed facility and ancillary structures, and where a minimal amount of demolition, equipment relocation and/or environmental remediation would be required. Additional benefit was considered if land was also available for use as temporary construction worker parking and laydown.
- Proximity to electric load. NRG favored sites providing ready access to markets with high electric load demand. The greatest priority was placed on SEMA/RI.
- Availability of natural gas. NRG considered those sites where a natural gas interconnection was 0.5 mile or less from the proposed site; where sufficient capacity was available; and where any pipeline-related construction could be completed consistent with the schedule for constructing the proposed power facility.
- Availability and ease of electrical interconnection. NRG strongly preferred interconnection at 345 kV, but considered sites where 115-kV or greater electrical interconnections were located within 0.5 mile from the site; where available capacity existed without the need for substantial electrical upgrades; and where any transmission-related construction could be completed consistent with the schedule for construction of the proposed power facility.
- Availability of water. Although large amounts of water are not required for a simple cycle facility, pollution control when firing ULSD requires a reliable supply of water. NRG considered sites with readily available water supplies to supply a reasonable volume and quality of water on a reliable basis.
- Compatibility with local zoning and surrounding uses. NRG considered sites that were compatible with existing uses, regulation and policy, as well as surrounding land uses. This includes consideration of the number of potential sensitive receptors in the surrounding area.
- Environmental Permitting Issues. NRG considered factors such as the permitting framework required for a facility in each location, the likely potential for natural or community impact, and the locational context from an air quality perspective.

Favorable evaluation of each of the above criteria was considered confirmation that the evaluated site would be a suitable location for the proposed project.

Environmental Considerations

Avoiding and minimizing environmental impacts is a critical element of NRG's sustainability practices. Therefore, a series of environmental considerations were reviewed for the candidate sites to focus on selecting a project location that could support the most environmentally favorable setting possible. The range of environmental issues considered for site selection included:

- Air quality
- Wetlands and waterways
- Zoning and land use
- Visual impact
- Solid and hazardous waste
- Material storage and safety
- Water use and discharge
- Noise
- Historic and archaeological resources
- Traffic and transportation
- Electric and magnetic field effect
- Proximity of construction laydown

Selection of a location that could effectively allow for environmental impacts to be minimized was considered to be a favorable location for the project.

Community Considerations

NRG employed the following community-related considerations as part of its process of selecting its site:

- support from municipal officials;
- importance of additional tax revenues;
- importance of project-related jobs; and
- support and/or buffer from neighbors.

Selection of a location with favorable community support and desire for the economic benefits associated with the Project was important to NRG.

C.1.3 Evaluation of Final Candidate Site Alternatives

Using the considerations set forth above, NRG evaluated and compared the Brayton Point, Canal, and Middletown sites. A closer investigation resulted in focusing on the following specific parcels:

- Brayton Point – The majority of the Brayton Point site is developed with existing facilities, or active and/or closed landfill areas. An approximately 15-acre portion of the property located north of the natural draft cooling towers appears to be available (as shown on Figure C-1), and has been selected for consideration.
- Canal – Two properties were identified in the initial screening that were potentially suitable for consideration, a 52-acre northern area and a 36-acre southern area. Because the 36-acre southern area is zoned for Business Limited uses (less compatible with the proposed project) and NRG has separate plans for developing a community solar project on that property, additional evaluation at the Canal site has focused on the 52-acre northern area (as shown on Figure C-2), within which an approximately 15-acre area is available. Nevertheless, the 36-acre southern area is considered in Section 3.5 as an alternative configuration of the preferred site.
- Middletown – The majority of the NRG Middletown site is under active use. However, a contiguous area of approximately 14.3 acres appears to be available to the east of the existing facilities (as shown on Figure C-3), and has been selected for consideration.

Although all three sites have attributes suitable for the project, as discussed in the sections below, the Canal site will result in the construction and operation of a proposed generating facility that will contribute to a reliable energy supply with a minimal impact on the environment at the lowest possible cost, and appropriately balances the range of siting considerations.

Locational Criteria

Table C-1 provides a comparison of locational attributes of the three potential development sites.

Table C-1: Comparison of Locational Criteria

Assessment Criteria	Brayton Point	Canal	Middletown
Adequate Site Size	The available site meets the minimum requirements.	The available site meets the minimum requirements.	The available site is narrow, but appears to meet the minimum requirements.
Availability of Construction Laydown and Parking	Construction laydown and parking areas are available on the property.	Construction laydown and parking areas are available on the property.	Limited additional area appears to be available for temporary construction parking and laydown.
Proximity to Electric Load	The site is in the preferred SEMA subregion and development at the site would, in part, replace the generation to be lost when the existing facility retires in 2017.	The site is in the preferred SEMA subregion. Further, as the only significant electric generating site on Cape Cod, the site is in good proximity to electric load, and the project in this location would add flexibility and reliability to the existing generating units.	The Site is not in the preferred SEMA subregion. Although in good proximity to electric load, existing NRG, GenConn, and the Kleen Energy facility are currently serving this immediate area.
Natural Gas	Natural gas infrastructure is available at this site.	Natural gas infrastructure is available at this site.	Natural gas infrastructure is available at this site.
Electrical Interconnection	Robust electrical interconnection is available at this site at 345 kV.	Robust electrical interconnection is available at this site at 345 kV.	Robust electrical interconnection is available at this site at 345 kV.
Water Availability	Potable water and appears to be available from the Town of Somerset. The facility also is currently supplied with treated effluent.	Water appears to be available from either ground or surface water sources.	Water appears to be available from either ground or surface water sources.

Assessment Criteria	Brayton Point	Canal	Middletown
Zoning/Land Use Compatibility	The site is industrially zoned and the location of a similar facility.	The site is industrially zoned and the location of a similar facility.	A portion of the site is zoned as Special Industrial, with the balance zoned as Riverfront Recreational (reflecting proximity to the Connecticut River), and is the location of a similar facility.
Permitting Process	Massachusetts requires comprehensive environmental review as well as appropriate resource permits.	Massachusetts requires comprehensive environmental review as well as appropriate resource permits.	Connecticut requires comprehensive environmental review as well as appropriate resource permits.

In summary, all three sites satisfied the locational criteria, although the more expansive and less narrow site availability at the Brayton Point and Canal locations was considered more ideal than the Middletown location, as it allows for siting flexibility as well as potential construction laydown area. The Brayton Point and Canal locations were also considered to be more favorable than Middletown from the perspective of electric demand and reliable service to customers as they are located in SEMA. Canal was deemed to be the most superior from this perspective as the only significant electric generating site on Cape Cod, providing a unique reliability addition to this load area.

Environmental Criteria

Table C-2 provides a comparison of environmental attributes of the two potential development sites.

Table C-2: Comparison of Environmental Criteria

Assessment Criteria	Brayton Point	Canal	Middletown
Air quality	Bristol County is in attainment of all National Ambient Air Quality Standards, with the exception of ozone for which it is a moderate non-attainment area. Terrain influence would be minimal, as the surroundings are relatively flat. The existing facility structures, if not demolished, could influence air quality dispersion from a proposed facility.	Barnstable County is in attainment of all National Ambient Air Quality Standards, with the exception of ozone for which it is a moderate non-attainment area. Terrain influence would be minimal, as the surroundings are relatively flat. The existing facility represents a major source that could influence dispersion as well as cumulative air quality impacts from a proposed facility.	Middlesex County is in attainment of all National Ambient Air Quality Standards, with the exception of ozone for which it is a moderate non-attainment area. Terrain in the vicinity is moderate and would be a consideration for dispersion modeling. The existing facility, as well as the nearby Kleen Energy facility, are major sources that could influence cumulative air quality impacts from a proposed facility.

Assessment Criteria	Brayton Point	Canal	Middletown
Water use and discharge	Potable and treated effluent sources exist at the site for consideration to serve a proposed facility. Given the low discharge volume anticipated, a feasible option is anticipated to be identified.	Existing groundwater sources at the site appear adequate to support a proposed facility. Given the low discharge volume anticipated, a feasible option is anticipated to be identified.	Surface water and groundwater sources exist at the site for consideration to serve a proposed facility. Given the low discharge volume anticipated, a feasible option is anticipated to be identified.
Wetlands and waterways	Much of the property is within mapped floodplain; mapped wetlands and Chapter 91 areas are also located on the site, but appear to be avoidable.	Much of the site is located within mapped floodplain. Public waterways access occurs along the Cape Cod Canal, consistent with Chapter 91 requirements. No wetland resources are known to be located on the site.	Much of the site is located within mapped floodplain. Waterfront Recreation occurs along the Connecticut River. Several pond and wetland areas are indicated by National Wetland Inventory maps as occurring within the site; field assessment would be required to determine mapping accuracy.
Noise	Massachusetts requires stringent noise limitations at the property boundary, compared with ambient sound as well as through an economic evaluation of mitigation options. Residential areas are located 0.2 mile east-southeast, 0.3 mile west, across the Lee River, and 0.4 mile north.	Massachusetts requires stringent noise limitations at the property boundary, compared with ambient sound as well as through an economic evaluation of mitigation options. The closest residential receptor is located across active rail tracks 0.05 mile southeast, with a larger residential development located 0.3 mile to the east.	Connecticut requires established project impact limitations at the property line adjusted based on surrounding land uses. The closest noise-sensitive receptor is the Saint Clements Castle & Marina, located approximately 0.3 mile northeast across the Connecticut River; a large residential neighborhood is located approximately 0.45 mile northeast of the site (also across the river).

Assessment Criteria	Brayton Point	Canal	Middletown
Zoning and land use	The site is industrially zoned and the location of a much larger electric generating facility.	The site is industrially zoned and the location of a much larger electric generating facility.	A portion of the site is zoned as Special Industrial, with the balance zoned as Riverfront Recreational (reflecting proximity to the Connecticut River), and is the location of a much larger electric generating facility. Other industrial uses are located along the riverfront to the east and west.
Historic and archaeological resources	The site has been significantly disturbed and is unlikely to be sensitive for archaeological resources. Views from any surrounding historic properties would not substantially change.	Although located within the King's Highway Historic District, the property identified has been disturbed and is unlikely to be sensitive for archaeological resources. Views from any surrounding historic properties would not substantially change.	This portion of the property is less developed than much of the remaining property and is also located proximate to a major river. As such, some evaluation to determine archaeological sensitivity would be expected. Views from any surrounding historic properties would not substantially change given the character of nearby land uses.
Visual impact	Sensitive visual receptors (residential areas) exist to the north, east and west. The existing facility is a more dominant visual element; given its dominant presence, visual change is not anticipated to be significant.	The site is proximate to Sandwich Marina, Scusset Beach State Reservation, and residences. The existing facility is a more dominant visual element; given its presence and vegetative screening, visual change is not anticipated to be significant.	The site is proximate to Dart Island State Park (adjacent to the north), as well as residential properties directly across the Connecticut River. The project in this location would extend a facility similar in character along the shoreline; screening by vegetation may limit visibility.

Assessment Criteria	Brayton Point	Canal	Middletown
Traffic and transportation	Location supports traffic associated with existing facility, which would remain largely unchanged.	Location supports traffic associated with existing facility, which would remain largely unchanged.	Location supports traffic associated with existing facility, which would remain largely unchanged.
Solid and hazardous waste	The greater facility site contains 12 closed (or in the processing of being closed) ash landfill cells. In addition, four separate historical remediation areas have been closed under two separate AULs. Significant long-term monitoring obligations would be associated with these site features.	As a long-time operating facility, the property may require consideration of historic contamination during construction efforts.	As a long-time operating facility, the property may require consideration of historic contamination during construction efforts.
Electric and magnetic field effect	The location of a substation on the property limits the need for an off-site interconnection and associated EMF issues.	The adjacent substation limits the need for an off-site interconnection and associated EMF issues.	The location of a substation on the property limits the need for an off-site interconnection and associated EMF issues.
Material storage and safety	No particular concerns were identified with regard to the transport and storage of chemicals and materials; similar existing uses currently do so safely.	No particular concerns were identified with regard to the transport and storage of chemicals and materials; similar existing uses currently do so safely.	No particular concerns were identified with regard to the transport and storage of chemicals and materials; similar existing uses currently do so safely.
Proximity of construction laydown	Additional land is available at this site to potentially accommodate temporary construction uses.	Additional land is available at this site to potentially accommodate temporary construction uses.	Additional land appears less likely to be available at this site to potentially accommodate temporary construction uses.

In summary, all three sites satisfied the environmental criteria, although the Brayton Point and Canal sites were considered more favorable than Middletown with regard to wetlands and waterways issues, archaeological sensitivity, and greater availability of land for the project and temporary construction laydown uses. Canal and Middletown were considered more favorable than Brayton Point with respect to solid and hazardous waste issues.

Community Criteria

The three potential sites were considered comparable with regard to community criteria. In each location, an existing facility results in long-term relationships with local officials and an ability to work within the local communities. Tax revenue from the existing facilities is an important element of local fiscal budgets, and an increase from a responsibly developed project is expected to be welcomed. Project-related jobs are important to the regional economy in all locations. All three sites provide for less obtrusive development, since they are located on the site of existing major facilities, although all three sites have relatively proximate neighbors for whom impacts must be carefully managed.

Conclusion

All three locations were considered to be potentially suitable for development of the Project. However, the availability of larger site areas to accommodate facility construction and the location of Brayton Point and Canal in the important SEMA/RI subregion were key factors in the elimination of Middletown from final selection.

The Brayton Point and Canal sites are both within SEMA, although Canal has the unique added advantage of enhancing reliability to Cape Cod as the only major electric generating facility on the Cape. Canal was deemed significantly superior to Brayton Point with respect to solid and hazardous waste since the latter has a number of closed ash landfills and two hazardous waste remediation sites closed with AULs on the property. For this reason, and since Brayton Point is not under NRG's ownership control, it does not otherwise present a clearly superior alternative. Therefore, the Canal site was selected as the preferred site.

C.1.4 Alternative Configurations at the Canal Site

Once NRG determined that Canal was its preferred site for a new generation facility, a project entity was established (Canal 3), and detailed investigations commenced. As a part of this effort, Canal 3 considered difference configurations of the project at the Site.

Canal 3 considered the two distinct parcels that comprise the 88-acre Property and selected the 52-acre northern area as superior to the 36-acre southern area for the following reasons.

- The northern area is zoned Industrial, while the southern area is zoned Business Limited.
- The southern area is less developed than the northern area.
- The southern area would involve a lengthier and more complex electrical interconnection to the Eversource switchyard.
- The northern area provides more operational efficiency being proximate to the existing Canal Generating Station and shared infrastructure (e.g., ammonia storage tanks) and can utilize or repurpose existing facilities (e.g., training building).
- The northern area provides more construction worker parking and equipment laydown options.

In evaluating appropriate layout considerations on the northern parcel, several primary design goals were utilized.

- Avoid wetland impact wherever possible.
- Utilize existing disturbed area.
- Minimize the need for existing equipment and structure relocation.
- Maintain a reasonable distance from site boundaries and public uses along the waterfront.
- Keep the NRG compact with the existing facility to preserve remaining land for future uses, including temporary construction laydown and parking.
- Consider visual and air dispersion effect in the orientation of the equipment.
- Maintain practical technical equipment orientation to facilitate construction and operations in an efficient, safe, and least-impact manner.

The resulting configuration accomplishes these objectives. The location of the proposed facility has been previously disturbed and contains limited natural resource value. No wetlands are located within the facility NRG (with the exception of Land Subject to Coastal Storm Flowage). Although several small ancillary structures will need to be relocated and/or demolished, the majority of the layout area is open and does not significantly constrain existing operations. The orientation of the facility allows for efficient routing of the electrical interconnection towards the adjacent substation, and places the facility with adequate buffer to the property line in all directions; a greater buffer adjacent to the waterfront has been maintained. The major equipment has been placed as close as possible to the existing structures, with the stack (the tallest element) oriented in a direction in order to minimize the effect of new visual elements. The orientation of the equipment, in an east-west direction, is the result of engineering functionality and air quality considerations.

The resulting project location best avoids natural resource encroachment, maximizes distance to residences and other sensitive off-site land uses, and result in the least visual change from off-site vantage points. Various iterations of equipment orientation were also considered, with selection of the proposed layout chosen as the most efficient and least intrusive option.

C.1.5 Conclusions

NRG Canal 3 has provided an accurate description of the site selection process, which resulted in the decision to develop and site a dual-fuel quick-start electric generating facility at the Canal site in Sandwich, Massachusetts. In addition to environmental and market considerations, NRG recognized the importance of siting its facility at a location: where natural gas, adequate electric transmission, and water were available; where there was sufficient space for a new facility and ancillary structures; and where the development of a new facility was compatible with both zoning and community planning objectives. Utilizing an existing NRG-owned facility allows the proposed project to capitalize on existing infrastructure and cause little to no impact on land use. NRG's site selection methodology was an integral part of a process that will contribute to a reliable energy supply with benefits that outweigh the minimal impact on the environment and social costs imposed as a result the construction and operation of the proposed facility at this location.

C.3 ALTERNATIVE PROJECT SIZES

At the close of ISO-NE's FCA #9 in February 2015, a shortfall of 238 MW of generation capacity was identified in the SEMA/RI capacity zone. Canal 3 has offered a capacity bid for the Project in ISO-NE's most recent forward capacity auction (FCA #10), which took place on February 10, 2016. The Canal 3 bid was accepted by ISO-NE.

By 2019, the year Canal 3 proposes the Project to be in-service, the total generating capacity in the market will be lower by more than 1,700 MW. This estimate is based on the expected generation retirements plus generation additions in ISO-NE FCA #8 and #9.

The proposed Project will provide the needed highly efficient, fast-starting, peak electric generation in the SEMA/RI capacity zone. With the ability to start up in 10 minutes, this flexible, fast-starting generation turbine will also provide critical support to the region's increasing generation from renewable energy sources. Further, with a simple-cycle turbine having dual-fuel capability, the Project will provide increased reliability to the ISO-NE system.

The gross electrical output of the CTG will vary from approximately 330 MW at higher ambient temperatures to approximately 365 MW at very low ambient temperatures. The net electrical output of the CTG will be slightly less due to use by auxiliary equipment associated with the Project.

The Project size was determined based upon the projected 1,700 MW reduction in ISO-NE capacity by 2019, participation in the ISO-NE TMNSR market, the site considerations discussed in Section C.1, and commercially available CTG technology. Based upon these considerations, it was determined that a roughly 350-MW simple-cycle CTG would be suitable for the Project. The available land, utilities, and associated environmental impacts as described in Section C.1 would not support a larger project. A smaller project would most likely require development on sites that are less desirable, as described in Section C.1, in order to meet the projected generating shortfall in 2019. The 350-MW Project capacity can be satisfied by a single H-class CTG that would minimize the Project's footprint as compared to alternative CTGs as discussed in Section C.3.

C.4 ALTERNATIVE PRODUCTION PROCESSES

As discussed in detail in the pre-filed direct testimony of Daniel Peaco before the Massachusetts Energy Facilities Siting Board (Appendix F), when compared to alternative fossil-fuel technologies, the proposed simple-cycle, dual-fuel, quick-start generating Project on balance contributes to a reliable, low-cost, diverse regional energy supply with minimal environmental impacts.

As an initial matter, Mr. Peaco provides an overview of the current state of the regional electricity system, and, in particular, discusses some of the challenges facing the system with respect to: (1) reliability of the system and the ability to ensure that generating capacity is available and developed when needed (specifically in response to planned retirements); (2) the need for new gas infrastructure to support the gas supply needed for electric generation; and (3) the importance of maintaining operational flexibility to support the region's increasing reliance on intermittent and variable renewable energy sources.

Indeed, Mr. Peaco's testimony shows that the attributes associated with the proposed Project– and specifically how 350 MW of state-of-the-art, dual-fuel, quick-start and flexible capacity – can help the region to address these challenges.

With respect to the fossil-fuel technology comparison, Mr. Peaco eliminated both exclusively oil-fired and coal-fired technologies from further consideration because such technologies faced significant cost, technological, and/or environmental hurdles, and, as such, neither technology appears to be feasible with respect to siting in Massachusetts (See pages 30 – 31 of Appendix F).

Mr. Peaco then compared the proposed GE 7HA.02 simple-cycle natural gas-fired turbine with two fossil-fuel alternatives: (1) the GE LMS 100, a natural gas-fired simple-cycle peaking technology; and (2) the Siemens SGT6-5000F 2x2x1, a natural gas-fired combined-cycle technology (See pages 32 – 40 of Appendix A). Specifically, Mr. Peaco then compared the three technologies with respect to: (1) reliability; (2) cost; (3) diversity in energy supply; and (4) environmental impacts (See pages 32–40 of Appendix F).

With respect to reliability, Mr. Peaco determined that the Project's GE 7HA.02 technology offers a number of positive attributes relative to other identified technologies. This type of technology has a better ramp rate at startup relative to the other technologies; is preferable to the combined-cycle technology with respect to ramping ability to full load; is equipped with automatic generation control (AGC) that will enable it to receive automatic dispatch signals from the system operator, which enables a fast response time in the event the system experiences unexpected losses of load, generation, or transmission; has comparable outage rates relative to the other technologies; and is capable of being constructed in significantly less time than the larger and more complex combined-cycle unit (See pages 32–33 of Appendix F).

With respect to cost, Mr. Peaco compared the three technologies on the bases of estimated capital costs (dollars per kilowatt [$/kW]), fixed O&M costs, and variable O&M costs. Mr. Peaco determined that the estimated overall capital costs and fixed O&M costs of the GE 7HA.02 technology were lower than those of the GE LMS100 and Siemens SGT6-5000F. Mr. Peaco also concluded that all three technologies have comparable estimated variable O&M costs. As such, Mr. Peaco determined that the combination of economic attributes of the GE 7HA.02 compared favorably to the other evaluated technologies.

With respect to diversity of energy supply, Mr. Peaco determined that the proposed Project technology offers diversity advantages over the LMS 100 due to its higher ramp rate and lower turn-down minimum. Moreover, Mr. Peaco determined that the efficiency and operating flexibility attributes of the combustion turbine technology will become increasingly more important to the system supply mix as the region increase its reliance on renewable energy resources and Canadian imports (See pages 35–36 of Appendix F).

With respect to environmental impacts, Mr. Peaco determined that the three selected technologies all will have lower heat rates than many of the existing, operating fossil fuel generating units, meaning higher efficient and lower variable O&M costs. These attributes will lead to these units being dispatched ahead of existing fossil fuel units, which generally are less efficient and have higher variable O&M costs (See page 34 of Appendix F).

As discussed in Section 5.2.7, Canal 3 recognizes that new “quick-start” combined-cycle technologies (a/k/a “flex plants”) have been developed that will allow a certain portion of the turbine output to be available in 10 minutes from initial startup, while the steam-cycle portion of the combined-cycle unit warms up. However, in order to be able to bring the required 300+ MW to the grid in 10 minutes, two F-class CTGs would be required to accomplish the same function in the TMNSR market as the proposed H-class CTG. The two F-class “quick-start” CTGs would provide 300+ MW for the TMNSR market as well as over 600 MW of combined cycle generation. This two-unit “quick-start” CTG plant would operate in a fundamentally different manner, requiring participation in both the TMNSR and day ahead energy markets to make the project financially viable. A much larger combined cycle project would require additional land for development, increase fuel consumption and dramatically increase water consumption. The wastewater cooling system would most likely require a dry cooling system that would be a significant new source of noise emissions. A single “quick-start” F-class combined-cycle unit would only be able to provide approximately 150 MW in in the TMNSR market. Neither one or two “quick-start” F-class combined-cycle units is considered commercially feasible since it would never be selected in the ISO-NE FCA due to the substantially higher capital cost and significantly diminished 10-minute generation capability relative to that cost.

C.5 ENVIRONMENTAL CONTROL TECHNIQUES

The Project will use natural gas as the primary fuel and ULSD as a back-up fuel, and will incorporate state-of-the-art control technology, resulting in extremely low emissions.

As discussed in detail in Section 4.0, the Project’s NO_x emissions will meet LAER. LAER requires the subject source to install pollution controls that result in the lowest emissions that are technically feasible. LAER can be no less stringent than BACT requirements. Section 5.0 of this application presents the BACT analysis required by the Massachusetts Air Pollution Control Regulations (310 CMR 7.00) for all Plan Approvals for all pollutants that MassDEP regulates under ambient air quality standards and emission regulations.

A top-down BACT analysis involving the following five-steps has been followed:

- identify all control technologies:
- eliminate technically infeasible options;
- rank remaining control technologies by control efficiency;
- evaluate most effective controls and document results; and,
- select BACT.

The BACT analysis presented in Section 5 details pollutant specific analyses for each of the combustion turbine and the ancillary combustion equipment (emergency diesel generator and emergency diesel fire pump).

There are no alternative environmental control techniques beyond those chosen for the Project that can lower air pollutant emissions.

C.6 EVALUATION OF PROJECT BENEFITS COMPARED TO ENVIRONMENTAL AND SOCIAL COSTS

With respect to Project benefits, an important benefit of the Project is the fact that it will add reliability to the regional electrical system and provide resources to support intermittent and variable resources, including renewable resources. Canal Station Units 1 and 2 are currently the only significant electric generating units on Cape Cod. Canal Station Units 1 and 2 each take approximately 12 hours to start up, and cannot respond to immediate power needs if there are problems with the electric supply or with the

supply of intermittent renewable resources such as solar and wind. The Canal 3 Project will be able to provide its full electric output capability in 10 minutes. This will provide a significant public benefit in terms of providing a quick response to system outages and also to support the market penetration of renewable resources. Renewable resources such as wind and solar are intermittent resources, since they depend of wind or sunshine being available in real time. If these resources are not available, the Project can provide quick backup power to replace these intermittent renewable resources until they become available again.

Another Project benefit is the fact that the Project will provide financial benefits including jobs during and after construction, and will have a significant positive impact on the Town of Sandwich's property tax base and local economy. The peak construction workforce is expected to include approximately 150 construction workers, which will bring positive economic impacts to these workers and their families as well as the local economy. NRG Canal 3 plans to locally source goods and services to support the Project during both construction and operation as much as feasible. In addition, NRG Canal 3 is developing a package of local support measures for the Town of Sandwich. The annual quantity of tax revenue from the Canal Station site is expected to double with the construction of the Canal 3 Project.

Another Project benefit is that Canal 3 will need to acquire Regional Greenhouse Initiative (RGGI) allowances in proportion to actual CO_2 emissions. RGGI funds are reinvested for public benefit, including investment in energy conservation measures which will reduce fuel use and emissions from such sources as home heating oil consumption.

An additional Project benefit is that since the Project will be dispatched ahead of older, less efficient generation on the electric grid, operation of the Project is projected to reduce regional CO_2 emissions.

While the Project will have certain environmental impacts and social costs, mitigation measures are incorporated into the Project in order to reduce emissions and any related social costs. In all cases Project impacts will meet the requirements of applicable laws and regulations that require minimization of impacts.

Regarding air quality, although the Project will result in emissions to the ambient atmosphere, the Project will not cause or contribute to an exceedance of any National or Massachusetts Ambient Air Quality Standard. This will be achieved through the implementation of Best Available Control Technology and Lowest Achievable Emission Rates, by using state-of-the-art equipment and control technology and by using natural gas and ultra-low sulfur diesel, the cleanest burning fossil fuels available. The Project will offset its NOx emissions by using offsets. The Project will also surrender CO_2 and SO_2 allowances under the RGGI and the federal Acid Rain Program, respectively.

MassDEP's Noise Policy limits the increase in residual (L_{90}) noise levels to no more than 10 A-weighted decibels (dBA) above ambient levels. Maximum sound level impacts from operation of the Project were calculated at the closest noise-sensitive receptors for both daytime and nighttime. During operation, the Project is expected to increase background sound levels by less than 7 dBA at the closest residence during the nighttime. Since ambient noise levels were found to be 5 to 10 dBA lower during the nighttime, daytime impacts would be less. A cumulative impact analysis was performed for the operation of the existing Units 1 and 2 and the proposed Project, even though simultaneous operation of all three units is expected to occur very infrequently. Results of this analysis led to incorporation of additional noise mitigation on Units 1 and 2 in order to reduce cumulative noise impacts. The proposed Project and existing Station will comply with MassDEP's Noise Policy during all operating scenarios, with a cumulative increase in nighttime L_{90} noise levels no greater than 10 dBA.

Regarding chemical storage, both the ULSD tanks and the aqueous ammonia storage tanks will be equipped with full secondary containment. Accidental release modeling found that the impacts of a complete failure of one aqueous ammonia tank are below applicable health impact thresholds at the fence line and beyond the Facility site.

With respect to wetland resources, the FEMA 100-year flood zone, also known as Land Subject to Coastal Storm Flowage (LSCSF), is the only wetland resource area, defined under the Massachusetts WPA and subject to Sandwich Wetland Bylaws, located on the Project Site. LSCSF has no specified performance standards set by the Massachusetts Wetland Protection Act (WPA). The proposed electrical transmission interconnection lines will traverse an offsite bordering vegetated wetland. Two poles will be placed in the buffer zone and heights of trees crossed will be maintained at no higher than 20 feet. In order to minimize potential impacts from coastal storms, the Project has been designed so that buildings and ancillary structures will be elevated 2.3 feet above the existing 100-year flood elevation, to a minimum elevation of 16 feet North American Vertical Datum of 1988 (NAVD-88). Temporary impacts during construction will be mitigated through the implementation of the Project's Storm Water Pollution Prevention Plan.

With respect to stormwater, prior to commencement of construction, a detailed erosion and sediment control plan will be prepared that meets current USEPA, MassDEP, Cape Cod Commission (CCC), and Town of Sandwich requirements and guidelines. During operation, the Project will control stormwater through installation of three vegetated infiltration basins. Any overflow from the infiltration basins will be directed to the two existing discharge points associated with the existing Station. The quality of stormwater runoff from the Project Site will be improved compared to existing conditions through the introduction of structural and non-structural Best Management Practices (BMPs) including deep sump catch basins, vegetated water quality swales, vegetated strips and infiltration basins with sediment forebays, and leaching catch basins. The design emphasizes infiltration and pretreatment pollutant removal efficiencies through the introduction of vegetation.

With respect to water and wastewater impacts, the Project has been designed to have insignificant impacts on water resources by utilizing a technology (simple-cycle combustion turbine) with inherently low water demand. Cumulative water demand for the Project and the existing Station will be met using the two existing groundwater wells on the Station Property, within the currently registered volumes. A near-zero liquid discharge design will avoid direct discharge of wastewater. Any liquid process streams that cannot be treated on-site will be collected and trucked off-site for treatment and disposal. Additionally, no new sanitary wastewater will be discharged, as the Project will utilize existing infrastructure currently serving the Station.

With respect to construction traffic, a traffic-construction management plan will be implemented to accommodate the specific needs of the site and to provide coordination with Town of Sandwich officials throughout the construction period.

It is concluded that the Project's benefits significantly outweigh the environmental and social costs. The Project has committed to reduce and/or mitigate any environmental and social impacts as a result of development of the Project. The Project will minimize emissions and will not cause or contribute to violation of any applicable air quality standard, through use of clean burning natural gas and ultra low sulfur distillate (ULSD) oil, advanced pollution control equipment, and highly efficient combustion turbines.

Legend

- Property Boundary
- Gas Pipeline
- Transmission Line
- NHESP Priority Habitats of Rare Species
- Historic Point
- Historic
- NHD Stream
- NHD Waterbody
- 100-year Flood Zone

NWI Wetland Type

- Estuarine and Marine Wetland
- Freshwater Emergent Wetland
- Freshwater Forested/Shrub Wetland

Imagery Source: NAIP, 2014

Figure C-1
Final Candidate Site:
Brayton Point

Bristol County, Massachusetts

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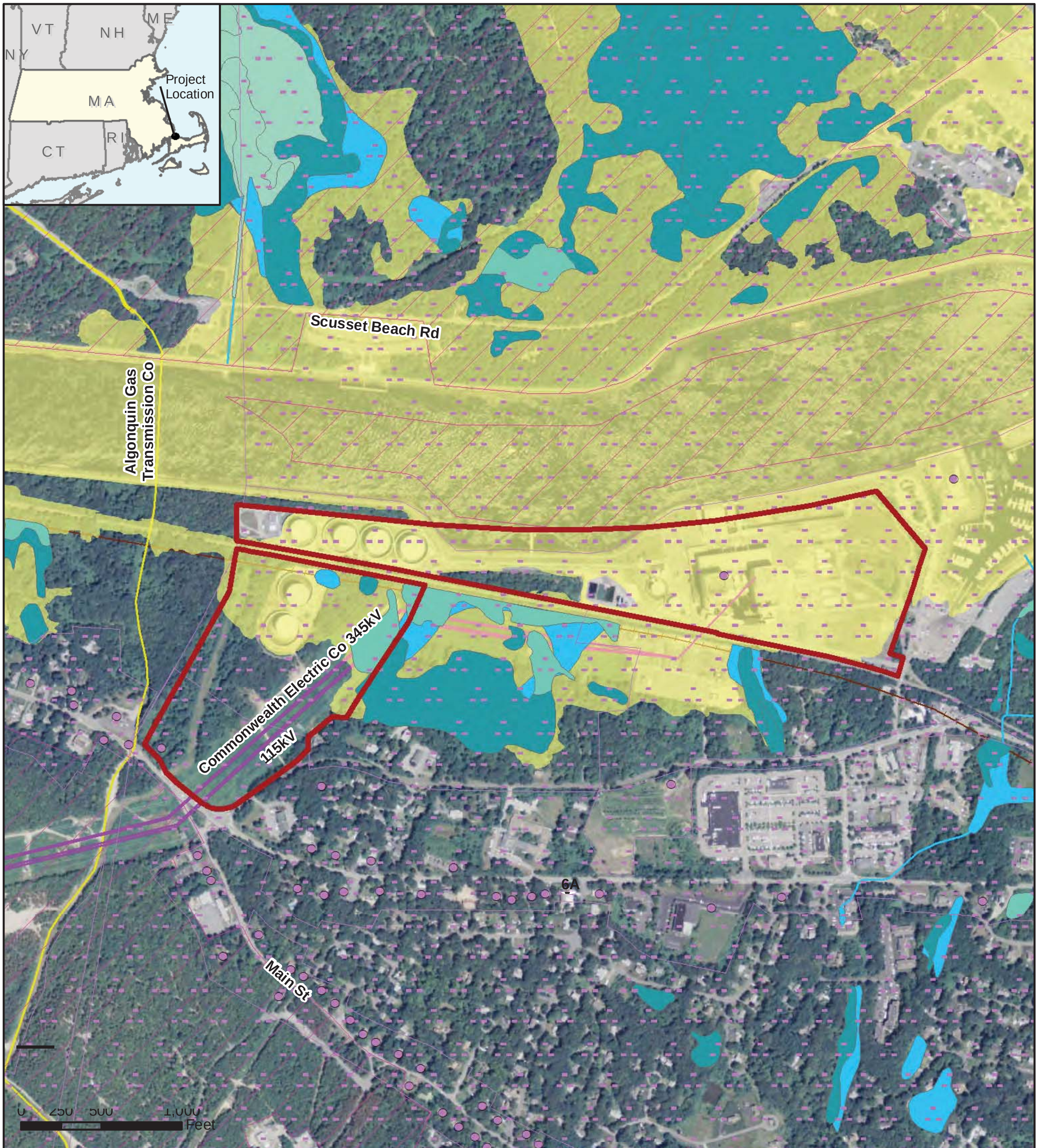

Legend

Property Boundary
Gas Pipeline
Transmission Line
Railroads
NHESP Priority Habitats of Rare Species
Historic Point
Historic
NHD Stream
NHD Waterbody
100-year Flood Zone
NWI Wetland Type
Estuarine and Marine Wetland
Freshwater Emergent Wetland
Freshwater Forested/Shrub Wetland

Imagery Source: NAIP, 2014

Figure C-2
Final Candidate Site:
Canal

Barnstable County, Massachusetts

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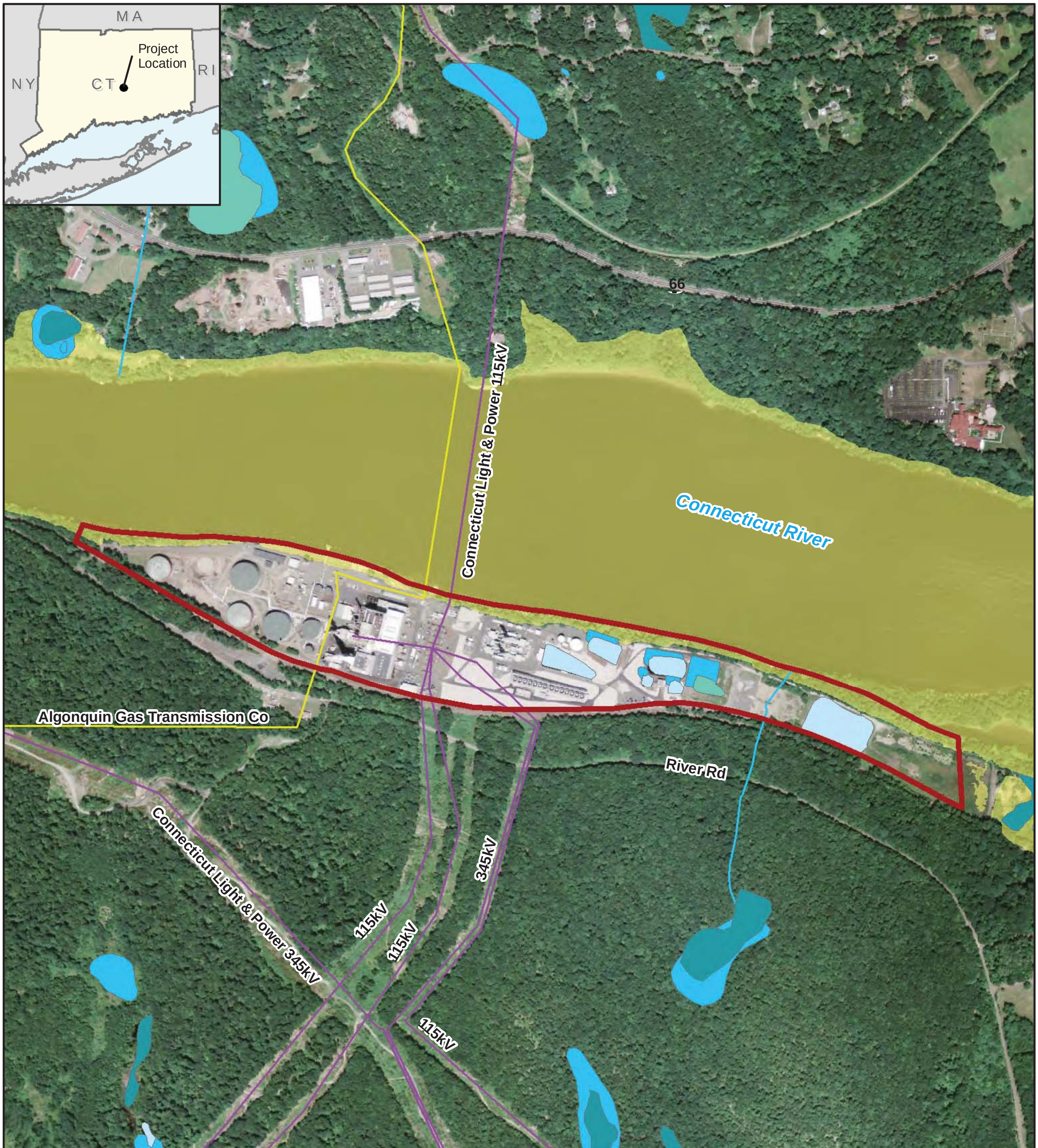

Legend

- Property Boundary
- Gas Pipeline
- Transmission Line
- NHD Stream
- NHD Waterbody
- 100-year Flood Zone

NWI Wetland Type

- Freshwater Emergent Wetland
- Freshwater Forested/Shrub Wetland
- Freshwater Pond

0 250 500 1,000 Feet

Imagery Source: NAIP, 2014

Figure C-3
Final Candidate Site: Middletown

Middlesex County, Connecticut

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APPENDIX D: BACT/LAER ANALYSIS SUPPORTING TABLES

Table D-1: Summary Of Recent NO_x PSD BACT and LAER Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits NO_x (ppmvdc at 15% O_2)	Control(s)
Navasota South Union Valley Energy Center	Nixon County TX	12/9/2015	3 – GE 7FA.04 (183 MW each)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Navasota North Van Alstyne Energy Center	Grayson County TX	10/27/2015	3 – GE 7FA.04 (183 MW each)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	9 ppmvdc	DLN Combustor
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	9 ppmvdc	DLN Combustors
Golden Spread Antelope Elk	Hale County, TX	5/12/2015	3 – GE 7F5	9 ppmvdc	DLN Combustors
Navasota South Clear Springs Energy Center	Guadalupe County, TX	5/8/2015	3 - GE 7FA.04 183 MW each	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03 (dual fuel)	15 ppmvdc (gas) (4-hr rolling avg.) 96 ppmvdc (gas <75%) (4-hr rolling avg.) 42.0 ppmvdc (oil) (4-hr rolling avg.) 96 ppmvdc (oil <75%) (4-hr rolling avg.)	DLN Combustors, water injection
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	6 – GE LMS100 PA	2.5 ppmvdc (1-hour)	SCR
Indeck Wharton Energy Center	Wharton, TX	02/02/2015	3- Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors

Table D-1: Summary Of Recent NO_x PSD BACT and LAER Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits: NO_x (ppmvdc at 15% O_2)	Control(s)
NRG SR Bertron	Harris, TX	12/19/2014	2 - Siemens F5, GE 7FA or Mitsubishi G	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Black Hills - Pueblo Airport Generating	Pueblo, CO	12/11/2014 (update) 7/22/2010 (original)	3 – GE LMS100 PA	5.0 ppmvdc (1-hr avg.)	Good combustion, water injection, SCR
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
NRG PH Robinson Electric Generating	Galveston, TX	05/20/2014	6 – GE 7EA	15.0 ppmvdc (3-hr rolling avg)	DLN Combustors
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F (dual fuel)	9.0 ppmvdc (gas) (24-hr rolling avg) 42.0 ppmvdc (oil) (4-hr rolling avg)	DLN Combustors, water injection (oil firing)
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014	3 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100 (dual fuel)	2.5 ppmvdc (gas) (3-hr rolling avg) 3.8 ppmvdc (oil) (3-hr rolling avg)	Good combustion, water injection, SCR
Guadalupe Power – Guadalupe Generating Station	Marion, TX	10/4/2013	2 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg.)	DLN Combustors
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	5.0 ppmvdc (4-hr rolling avg)	Good combustion, SCR

Table D-1: Summary Of Recent NO_x PSD BACT and LAER Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits NO_x (ppmvdc at 15% O_2)	Control(s)
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	5.0 ppmvdc (4-hr rolling avg)	Good combustion, water injection, SCR
Invenergy Thermal Development LLC - Ector County Energy Center	Ector, TX	05/13/2013	2 - GE 7FA.03 or GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
El Paso – Montana Power Station	El Paso, TX	04/02/2013	4 – GE LMS100	2.5 ppmvdc	Good combustion, SCR
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	9.0 ppmvdc (4-hr rolling avg., >50 MWE & >0°F) 96.0 ppmvdc (4-hr rolling avg., <50 MWE & <0°F)	DLN Combustors
Pio Pico Energy Center	Otay Mesa, CA	11/19/2012	3 - GE LMS100	2.5 ppmvdc (1-hr avg.)	Good combustion, water injection, SCR
NRG Cedar Bayou Electric Generation Station	Chambers, TX	09/12/2012	2 - Siemens Model F5, GE 7FA, or Mitsubishi G Frame	9.0 ppmvdc (3-hr rolling avg.)	DLN Combustors
Black Hills - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000 PF Sprint (3 operate in simple cycle & 2 in combined cycle)	5.0 ppmvdc (1-hr rolling avg.)	Good combustion, SCR
EFS Shady Hills	Pasco County FL	4/6/2012	2 - GE 7FA.05	9.0 ppmvdc (gas) 42 ppmvdc (oil)	DLN Combustors, water injection (oil)
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	17.5 ppmvdc	DLN Combustors
Wolverine Power	Presque Isle County MI	6/29/2011	540 MMBtu/hr oil-fired Black Start Turbine for Coal-Fired Power Plant	0.16 lb/MMBtu	No controls specified

Table D-1: Summary Of Recent NO_x PSD BACT and LAER Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits: NO_x (ppmvdc at 15% O_2)	Control(s)
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	2 – Westinghouse 501D5A	21.0 ppmvdc (w/o PA) 30.0 ppmvdc (with PA)	DLN Combustors Type K, Good Combustion
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	2.5 ppmvdc (3-hr rolling avg.)	Good combustion, Natural gas, water injection, SCR
VMEU – Howard Down Station	Cumberland, NJ	09/16/2010	1 – Trent 60	2.5 ppmvdc (3-hr rolling avg.)	Good combustion, Natural gas, water injection, SCR
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	5.0 ppmvdc (1-hr)	Good combustion, water injection, SCR
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F Dual fuel	9.0 ppmvdc (gas) 42 ppmvdc (oil)	DLN Combustors, water injection (oil)
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	2.5 ppmvdc (1-hr)	Good combustion, water injection, SCR
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	42 ppmvdc (gas/oil) (1-hr avg)	DLN (gas) and water injection (oil)
Gowanus Expansion	New York, NY	2009	1 – GE LMS100 Dual fuel	2.5 ppmvdc (gas) (1-hr) 3.5 ppmvdc (oil) (1-hr)	Good combustion, water injection, SCR
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	2.5 ppmvdc (gas) (1-hr) 5.0 ppmvdc (oil) (1-hr)	Good combustion, water injection, SCR

Table D-2: Summary Of Recent VOC PSD BACT and LAER Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits VOC (ppmvdc at 15% O_2[1])	Control(s)
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	2 ppmvdc	Good combustion
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	1.4 ppmvdc	Good combustion
Golden Spread Antelope Elk	Hale County, TX	5/12/2015	3 – GE 7F5	2 ppmvdc	Good combustion
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03	1.4 ppmvdc (gas) (1-hr) 3.5 ppmvdc (oil) (1-hr)	Good combustion
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	6 – GE LMS100 PA	2.0 ppmvdc (1-hour))	Oxidation Catalyst
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	1.4 ppmvdc (GE) 1.0 ppmvdc (Siemens)	DLN Combustors
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	3.77 lb/hr (gas) 8.00 lb/hr (oil)	DLN Combustors
Black Hills Power, Inc. - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000	3.0 ppmvdc (3-hr rolling avg.)	Oxidation Catalyst
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	3.0 ppmvdc	DLN Combustors
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	4.0 ppmvdc	Oxidation Catalyst, Good combustion, Natural gas

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits	Control(s)
				VOC (ppmvdc at 15% O_2[1])	
Braintree Electric – Watson	Braintree, MA	09/2010	2 – Trent 60	2.5 ppmvdc (gas) (1-hr) 4.5 ppmvdc (oil) (1-hr)	Good combustion, Oxidation catalyst
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	2.5 ppmvdc (1-hr)	Good combustion, Oxidation catalyst
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F	5.0 ppmvdc (gas) (3-hr avg.) 5.0 ppmvdc (ULSD) (3-hr avg.)	Good combustion, Oxidation catalyst
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	2.0 ppmvdc (1-hr)	Good combustion, Oxidation catalyst

[1] Parts per million by volume (dry) corrected to 15% oxygen

Table D-3: Summary Of Recent CO PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits CO (ppmvdc at 15% O_2)	Control(s)
Navasota South Union Valley Energy Center	Nixon County TX	12/9/2015	3 – GE 7FA.04 (183 MW each)	9.0 ppmvdc (3-hr rolling avg)	DLN combustors, good combustion practices
Navasota North Van Alstyne Energy Center	Grayson County TX	10/27/2015	3 – GE 7FA.04 (183 MW each)	9 ppmvdc	DLN combustors, good combustion practices
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	9 ppmvdc	DLN combustor, good combustion practices
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	9 ppmvdc	DLN Combustors
Golden Spread Antelope Elk	Hale County, TX	5/19/2015	3 – GE 7F5	9 ppmvdc	DLN Combustors, good combustion
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03 Dual fuel	4.0 ppmvdc (gas) (1-hr) 8 ppmvdc (oil) (1-hr)	Good combustion
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	6 – GE LMS100 PA	4.0 ppmvdc (1-hour))	Oxidation Catalyst
Indeck Wharton Energy Center	Wharton, TX	02/02/2015	3 - Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	GE - 9.0 ppmvdc (3-hr rolling avg) Siemens - 4.0 ppmvdc (3-hr rolling avg)	DLN Combustors, good combustion
NRG SR Bertron	Harris, TX	12/19/2014	2 - Siemens F5, GE 7FA or Mitsubishi G	9.0 ppmvdc (1-hr)	DLN Combustors
Black Hills - Pueblo Airport Generating	Pueblo, CO	12/11/2014 (update) 7/22/2010 (original)	3 – GE LMS100 PA	10 ppmvdc (1-hr avg.)	Good combustion, water injection, oxidation catalyst

Table D-3: Summary Of Recent CO PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits CO (ppmvdc at 15% O_2)	Control(s)
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
NRG PH Robinson Electric Generating	Galveston, TX	05/20/2014	6 – GE 7EA	25.0 ppmvdc (3-hr rolling avg)	DLN Combustors
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F Dual fuel	4.0 ppmvdc (gas) 9.0 ppmvdc (oil)	DLN Combustors
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014	3 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	DLN Combustors
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100 Dual fuel	6.0 ppmvdc (gas & oil) (3-hr rolling avg)	Oxidation Catalyst
Guadalupe Power – Guadalupe Generating Station	Marion, TX	10/4/2013	2 - GE 7FA.05	9.0 ppmvdc (3-hr rolling avg.)	DLN Combustors
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	6.0 ppmvdc (8-hr rolling avg)	Oxidation Catalyst
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	6.0 ppmvdc (8-hr rolling avg)	Oxidation Catalyst
Invenergy Thermal Development LLC - Ector County Energy Center	Ector, TX	05/13/2013	2 - GE 7FA.03 or GE 7FA.05	9.0 ppmvdc (3-hr rolling avg)	
El Paso – Montana Power Station	El Paso, TX	04/02/2013	4 – GE LMS100	6.0 ppmvdc	Oxidation Catalyst

Table D-3: Summary Of Recent CO PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits CO (ppmvdc at 15% O_2)	Control(s)
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	25.0 ppmvdc (4-hr rolling avg., >50 MWE) 27 tons (30-day rolling total, <50 MWE)	Good combustion
NRG Cedar Bayou Electric Generation Station	Chambers, TX	09/12/2012	2 - Siemens Model F5, GE 7FA, or Mitsubishi G Frame	9.0 ppmvdc (1-hr rolling avg)	Good combustion
Black Hills Power, Inc. - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000	6.0 ppmvdc (1-hr rolling avg.)	Oxidation Catalyst
EFS Shady Hills	Pasco County FL	4/6/2012	2 - GE 7FA.05 Dual fuel	9.0 ppmvdc (gas) 42 ppmvdc (oil)	Good combustion
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	15.0 ppmvdc	DLN Combustors
Wolverine Power	Presque Isle County MI	6/29/2011	540 MMBtu/hr oil-fired Black Start Turbine for Coal-Fired Power Plant	0.045 lb/MMBtu	No controls specified
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	2 – Westinghouse 501D5A	77.2 lb/hr (w/o power augmentation) 138.9 (w/ power augmentation	Good Combustion
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	5.0 ppmvdc (3-hr rolling avg.)	Oxidation Catalyst, Good combustion, Natural gas
VMEU – Howard Down Station	Cumberland , NJ	09/16/2010	1 – Trent 60	5.0 ppmvdc (3-hr rolling avg.)	Oxidation Catalyst, Good combustion, Natural gas
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	10.0 ppmvdc (1-hr)	Good combustion, Oxidation catalyst

Table D-3: Summary Of Recent CO PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits CO (ppmvdc at 15% O_2)	Control(s)
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F Dual fuel	9.0 ppmvdc (gas) (3-hr avg.) 30.0 ppmvdc (ULSD) (3-hr avg.)	Good Combustion
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	4.0 ppmvdc (3-hr avg.)	Good combustion, Oxidation catalyst
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	20 ppmvdc (gas/oil) (3-hr avg)	Efficient combustion technology
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	5.0 ppmvdc (gas & oil) (1-hr)	Good combustion, water injection, SCR

Table D-4: Summary Of Recent Particulate PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted – otherwise emissions are gas-fired values)	Emission Limits $PM/PM_{10}/PM_{2.5}$ (lb/MMBtu)	Control(s)
Navasota South Union Valley Energy Center	Nixon County TX	12/9/2015	3 – GE 7FA.04 (183 MW each)	8.6 lb/hr *(0.005 lb/MMBtu*	Pipeline quality natural gas
Navasota North Van Alstyne Energy Center	Grayson County TX	10/27/2015	3 – GE 7FA.04 (183 MW each)	8.6 lb/hr *(0.005 lb/MMBtu)*	Pipeline quality natural gas
Nacogdoches Power LLC	Nacogdoches County TX	10/14/2015	1 – Siemens F5 (232 MW)	12.09 lb/hr *(0.005 lb/MMBtu)*	Natural gas and good combustion practices

Table D-4: Summary Of Recent Particulate PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted – otherwise emissions are gas-fired values)	Emission Limits: $PM/PM_{10}/PM_{2.5}$ (lb/MMBtu)	Control(s)
Shawnee Energy Center	Hill County, TX	10/9/2015	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	84.1 lb/hr *(0.04 lb/MMBtu)*	Natural gas and good combustion practices
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03 Dual fuel	2.0 gr. S/100 scf & 0.0015% sulfur fuel oil	Natural gas as primary fuel & ULSD
Black Hills - Pueblo Airport Generating	Pueblo, CO	12/11/2014	2 – GE LMS100	6.6 lb/hr *(0.008 lb/MMBtu)*	Natural gas as primary fuel
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	9.3 lb/hr (GE) *(0.005 lb/MMBtu)* 10 lb/hr (Siemens) *(0.005 lb/MMBtu)*	Natural gas as primary fuel
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100	9.1 lb/hr (gas) *(0.01 lb/MMBtu)* 22.74 lb/hr (oil) (*0.03 lb/MMBtu*)	Natural gas as primary fuel
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	5.0 lb/hr (*0.012 lb/MMBtu*)	Natural gas as primary fuel
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	5.4 lb/hr (*0.012 lb/MMBtu*)	Natural gas as primary fuel

Table D-4: Summary Of Recent Particulate PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted – otherwise emissions are gas-fired values)	Emission Limits PM/PM_{10}/$PM_{2.5}$ (lb/MMBtu)	Control(s)
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	7.3 lb/hr (*0.007 lb/MMBtu*)	Natural gas as primary fuel, and Good combustion
Pio Pico Energy Center	Otay Mesa, CA	11/19/2012	3 - GE LMS100	0.0065 lb/MMBtu (>80%) 5.5 lb/hr	Natural gas as primary fuel
Black Hills Power, Inc. - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000 (3 simple cycle and 2 combined cycle)	4.0 lb/hr (*0.010 lb/MMBtu*) 17.5 TPY	Natural gas as primary fuel, Good combustion
EFS Shady Hills	Pasco County FL	4/6/2012	2 - GE 7FA.05 Dual fuel	2.0 gr. S/100 scf & 0.0015% sulfur fuel oil	Good combustion
Entergy Gulf States La Calcasieu Plant	Calcasieu, LA	12/21/2011	2 – unspecified turbines	17 lb/hr (*0.009 lb/MMBtu*)	Natural gas as primary fuel, Good combustion
Wolverine Power	Presque Isle County MI	6/29/2011	540 MMBtu/hr Black Start Turbine for Coal-Fired Power Plant	0.03 lb/MMBtu (Oil)	No controls specified
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	2 – Westinghouse 501D5A	5.4 lb/hr	Natural gas as primary fuel, Good Combustion
PSEG Fossil - Kearny Generating Station	Hudson, NJ	10/27/2010	6 – GE LM6000 sprint	6.0 lb/hr (*0.012 lb/MMBtu*)	Good combustion, Natural gas

Table D-4: Summary Of Recent Particulate PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted – otherwise emissions are gas-fired values)	Emission Limits PM/PM_{10}/$PM_{2.5}$ (lb/MMBtu)	Control(s)
VMEU – Howard Down Station	Cumberland, NJ	09/16/2010	1 – dual fuel Trent 60 (590 MMBtu/hr gas; 569 MMBtu/hr oil)	5.0 lb/hr *(0.008 lb/MMBtu)*	Good combustion, Natural gas (RBLC only appears to list gas limits)
Black Hills - Pueblo Airport Generating	Pueblo, CO	07/22/2010	3 – GE LMS100PA	6.6 lb/hr (*0.008 lb/MMBtu*)	Good combustion
Southern Power – Dahlberg Generating Facility	Jackson, GA	05/14/2010	4 – Siemens SGT G-5000F	9.1 lb/hr (gas) (*0.004 lb/MMBtu*) 69.0 lb/hr (ULSD) (*0.03 lb/MMBtu*)	Natural gas as primary fuel, ULSD
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	2.5 lb/hr 0.75 gr-S/100 dscf	Good combustion, Natural gas
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	0.026 lb/MMBtu (gas/oil)	Clean fuels (Test Method specified as Method 5 (normally filterable only)
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	5.0 lb/hr, 0.02 lb/MMBtu (gas) 15.0 lb/hr, 0.05 lb/MMBtu (oil)	Good combustion, water injection, SCR

Table D-5: Summary Of Recent SO2 and H_2SO_4 PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits H_2SO_4 (lb/MMBtu)	Control(s)
Indeck Wharton Energy Center	Wharton, TX	02/02/2015	3- Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	0.2 gr/S/100 ft3 nat gas	Natural gas as primary fuel
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	0.5 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	1.0 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
NRG PH Robinson Electric Generating	Galveston, TX	05/20/2014	6 – GE 7EA	0.5 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
FP&L Lauderdale	Broward, FL	04/22/2014	5 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	2.0 gr/S/100 ft^3 (nat gas) 15 ppmw (oil)	Natural gas as primary fuel, oil ≤500 hrs/yr
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014	3 - GE 7FA.05	1.0 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
Guadalupe Power – Guadalupe Generating Station	Marion, TX	10/4/2013	2 - GE 7FA.05	0.5 gr/S/100 ft^3 nat gas	Natural gas as primary fuel
Southwestern PSC – Cunningham Power Plant	Lea, NM	05/02/2011	unspecified turbines	5.25 gr S/100 scf 0.25 gr H_2S/100 scf	Natural gas as primary fuel, Good Combustion
TID Almond 2 Power Plant	Modesto, CA	02/16/2010	3 – GE LM6000 PG Sprint	0.75 gr-S/100 dscf	Natural gas as primary fuel
Dayton Power & Light	Montgomery County OH	12/03/2009	4 dual fuel (gas/oil) turbines rated at 80 MW each	0.0054 lb/MMBtu (gas/oil)	Low sulfur fuel oil

Table D-6: Summary Of Recent GHG PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits PM/PM_{10}/$PM_{2.5}$ (lb/MMBtu)	Control(s)
Navasota North Van Alstyne Energy Center	Grayson County TX	1/13/2016 (GHG)	3 - GE 7FA.04 183 MW each	1,461 lb CO2e/MWhr	Natural gas
Navasota South Union Valley Energy Center	Guadalupe County, TX	12/16/2015 (GHG)	3 - GE 7FA.04 183 MW each	1,461 lb CO2e/MWhr	Natural gas
Navasota South Clear Springs Energy Center	Guadalupe County, TX	11/13/2015 (GHG)	3 - GE 7FA.04 183 MW each	1,461 lb CO2e/MWhr	Natural gas
Shawnee Energy Center	Hill County, TX	11/10/2015 (GHG)	4- Siemens SGT6-5000F5 (230 MW each) or GE 7FA.05TP (227 MW each)	1,398 lb CO2e/MWhr	Natural gas
NRG Cedar Bayou	Hill County, TX	9/15/2015	2 CTGs - GE 7HA (359 MW) or GE 7FA (215 MW) or Siemens SF5 (225 MW) or MHI 501G (263 MW)	1232 lb CO2/MWhr	Natural gas; RBLC listed for simple and combined cycle mode; CO2 emission rate is listed under simple cycle BACT
Golden Spread Antelope Elk	Hale County, TX	5/19/2015	3 – GE 7F5	1304 lb CO2e/MWhr	Natural gas, energy efficiency and good combustion practices
Duke Suwannee River Power Plant	Live Oak, FL	04/28/2015	2 – GE 7FA.03	1,409 lb CO_2e/MW-hr (gas) 1,973 lb CO_2e/MW-hr (oil)	Natural gas as primary fuel, good combustion
Indeck Wharton Energy Center	0Wharton, TX	5/12/2014 (GHG)	3- Siemens SGT6-5000F (227 MW) or GE 7FA (214 MW)	1,337 lb CO2/MW-hr (gross) (Siemens) 1,276 lb CO_2/MW-hr (gross) (GE)	Natural gas as primary fuel, good combustion

Table D-6: Summary Of Recent GHG PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits PM/PM_{10}/$PM_{2.5}$ (lb/MMBtu)	Control(s)
Guadalupe Power – Guadalupe Generating Station	Marion, TX	12/02/2014 (GHG) 10/4/2013	2 - GE 7FA.05	1,293.3 lb CO_2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014 08/1/2014 (GHG)	2 - GE 7FA.04, GE 7FA.05 or Siemens SGT6-5000F	1,334 lb CO_2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	2 - GE 7FA.03 (165 MW) or 2 - GE 7FA.05 (193 MW)	1,393 lb CO_2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Exelon Perryman 6	MD	05/2014	1 - Pratt & Whitney FT4000 (120 MW)	1,394 lb CO_2/MW-hr (gas, gross) 1,741 lb CO_2/MW-hr (oil, gross)	Natural gas as primary fuel, good combustion
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014 06/02/2014 (GHG)	1 - GE 7FA.05	1,304 lb CO_2/MW-hr (gross)	Natural gas as primary fuel, good combustion
Troutdale Energy Center	Multnomah, OR	03/05/2014	2 - GE LMS-100	1,707 lb CO_2/Gross MWH (365-day rolling avg.)	Natural gas as primary fuel
Basin EPC Lonesome Creek Generating Station	McKenzie, ND	09/16/2013	3 - GE LM6000 PF Sprint	220,122 tons (12-mo. rolling avg.)	Natural gas as primary fuel, high efficiency turbines
Basin EPC Pioneer Generating Station	Williams, ND	05/14/2013	3 - GE LM6000 PF Sprint	243,147 tons (each unit) (12-mo. rolling avg.)	Natural gas as primary fuel, high efficiency turbines
Montana-Dakota Utilities Co. R.M. Heskett Station	Morton, ND	02/22/2013	1 - GE Model PG 7121 (7EA)	413,198 tons/12 mo. rolling total	Natural gas as primary fuel, good combustion

Table D-6: Summary Of Recent GHG PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model (facilities designated as dual fuel or oil only are noted –otherwise emissions are gas-fired values)	Emission Limits	Control(s)
				$PM/PM_{10}/PM_{2.5}$ (lb/MMBtu)	
Pio Pico Energy Center	Otay Mesa, CA	11/19/2012	3 - GE LMS100	1,328 lb/MW-H (Gross Output)	Natural gas as primary fuel, good combustion
Black Hills - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012 09/27/2012 (GHG)	5 – GE LM6000 PF (3 in simple cycle & 2 in combined cycle)	1,600 lb CO_2/MW-hr (gross)	Natural gas as primary fuel, good combustion

Table D-7: Summary of Recent NH_3 PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits	Control(s)
				NH_3 (lb/MMBtu)	
Black Hills - Cheyenne Prairie Generating Station	Laramie, WY	08/28/2012	5 – GE LM6000 PF (3 in simple cycle & 2 in combined cycle)	10 ppmvdc	No controls feasible
Braintree Electric – Watson	Braintree, MA	04/04/2008	2 – Trent 60 Dual fuel	5 ppmvdc	SCR design and operation

Table D-8: Summary of Recent Formaldehyde PSD BACT Determinations for Simple-Cycle Generating Plants

Facility	Location	Permit Date	Turbine Make & Model	Emission Limits Formaldehyde (lb/MMBtu)	Control(s)
Dayton Power & Light Energy LLC	Montgomery County OH	1203/2009	4 Simple cycle turbines (80 MW) (both gas & oil)	0.0006	None specified
Dayton Power & Light Energy LLC	Montgomery County OH	1203/2009	3 Simple cycle turbines (80 MW) (both gas & oil)	4.2 tpytotal based on 0.0007 lb/MMBtu	None specified
Rolling Hills Generating, LLC	Vinton County OH	09/22/2014	5 - Siemens W501F (209 MW)	0.99 lb/hr/turbine *(0.0006 lb/MMBtu)*	Natural gas and DLN combustors

Table D-9: Summary of Recent PSD BACT Determinations for Emergency Generator Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Towantic Energy Center	Oxford, CT	11/30/2015	1500 kW	19.84 lb/hr (6.0 grams/kWhb ased on electrical kW)	2.14 lb/hr	0.53 lb/hr	0.15 lb/hr	0.02 lb/hr SO_2 $1.66x10^{-3}$ lb/hr H_2SO_4	163.6 lb/MMbtu
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	779 hp (500 kW)	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	128 tpy
Moundsville Power	Moundsville WV	11/21/2014	1500 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	2416 lb/hr 604 tpy
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	2,937 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	156 tpy
Goldenspread Antelope Elk Energy	Hale, TX	04/22/2014 06/02/2014 (GHG)	1,656 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	128 tpy
FP&L Lauderdale	Broward, FL	04/22/2014	4 – 3,100 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	N/A
Footprint Power Salem Harbor	Salem MA	01/30/2014	750 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.0009 lb/hr H_2SO_4 *(0.0005 gram/kWhr)*	162.85 lb/MMBtu
Berks Hollow	Ontelaunee Twnshp,PA	12/17/2013	60 gal/hr (approx. 850 kW)	0.53 tpy	0.03 tpy	0.29 tpy	0.017 tpy	ULSD SO2 0.0001 tpy H2SO4	--

Table D-9: Summary of Recent PSD BACT Determinations for Emergency Generator Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Carroll County Energy	Washington Twp., OH	11/5/2013	1112 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	433.96 tpy
Renaissance Power	Carson City, MI	11/1/2013	(2) – 1000 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	1731.4 tpy (both units)
Langley Gulch Power	Payette, ID	08/14/2013	750 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	--
Oregon Clean Energy	Oregon, OH	06/18/2013	2250 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	878 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	1500 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	750 kW	6.0 gm/kWhr	0.4 gm/kWhr	Subpart IIII	0.02 tpy	ULSD SO_2	80.5 tpy
Brunswick County Power	Freeman, VA	03/12/2013	2200 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	1472 hp	4.93 gms/hp-hr	0.01 gms/hp-hr	0.13 gms/hp-hr	0.02 gms/hp-hr	ULSD SO_2	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 1006 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	--

[1] Generators are diesel generators except where noted.

[2] Limits obtained from agency permitting documents when not available in RBLC.

Table D-10: Summary of Recent PSD BACT Determinations for Emergency Fire Pump Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Towantic Energy Center	Oxford, CT	11/30/2015	350 hp	2.65 lb/hr	0.64 lb/hr	0.07 lb/hr	0.1 lb/hr	$3.7x10^{-3}$ lb/hr SO_2 $2.8x10^{-4}$ lb/hr H_2SO_4	163.6 lb/MMbtu
Duke Suwannee River Power	Live Oak, FL	04/28/2015	160 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	N/A
Carlsbad Energy Center	Carlsbad, CA	04/17/2015	327 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	128 tpy
Moundsville Power	Moundsville WV	11/21/2014	251 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	309 lb/hr 77 tpy
Tenaska Roan's Prairie Partners	Grimes, TX	09/22/2014	575 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	33 tpy
Invenergy Ector County Energy Center	Ector, TX	08/01/2014	250 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	5 tpy
FP&L Lauderdale	Broward, FL	04/22/2014	300 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	N/A	N/A
Footprint Power Salem Harbor	Salem MA	01/30/2014	371 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.0009 lb/hr H_2SO_4 *(0.0005 gram/kWhr)*	162.85 lb/MMBtu
Berks Hollow	Ontelaunee Twnshp,PA	12/17/2013	60 gal/hr (approx. 320 hp)	0.09 tpy	0.013 tpy	0.09 tpy	0.005 tpy	ULSD SO2 0 tpy H2SO4	--

Table D-10: Summary of Recent PSD BACT Determinations for Emergency Fire Pump Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Carroll County Energy	Washington Twp., OH	11/5/2013	400 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	115.75 tpy
Consumers Energy Thetford Station	Thetford Twp, MI	7/25/2013	315 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	--	15.6 tpy
Oregon Clean Energy	Oregon, OH	06/18/2013	2250 kW	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2 0.000132 H_2SO_4 grams/kWhr	87 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	330 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	450 hp	1.9 gm/bhp-hr	1.1 gm/bhp-hr	Subpart IIII	Subpart IIII	0.00012 grams/bhp-hr	33.8 tpy
Brunswick County Power	Freeman, VA	03/12/2013	305 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	460 hp	2.6 gms/hp-hr	0.1 gms/hp-hr	0.5 gms/hp-hr	0.09 gms/hp-hr	ULSD SO_2	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 371 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	172 tpy

Table D-10: Summary of Recent PSD BACT Determinations for Emergency Fire Pump Engines at Simple-Cycle Generating Plants

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits					
				NO_x	CO	VOC	PM	H_2SO_4	GHGs
Hess Newark Energy Center	Newark, NJ	11/01/2012	270 hp	Subpart IIII	Subpart IIII	Subpart IIII	Subpart IIII	ULSD SO_2	--
ES Joslin Power	Calhoun, TX	09/12/2012	size not given	2.08 lb/hr	0.79 lb/hr	1.82 lb/hr	0.10 lb/hr	ULSD SO_2	--
Moxie Liberty LLC	Asylum Twp, PA	10/10/2012	size not given	2.6 gms/hp-hr	0.1 gms/hp-hr	0.5 gms/hp-hr	0.09 gms/hp-hr	ULSD SO_2	--

[1] Generators are diesel generators except where noted.

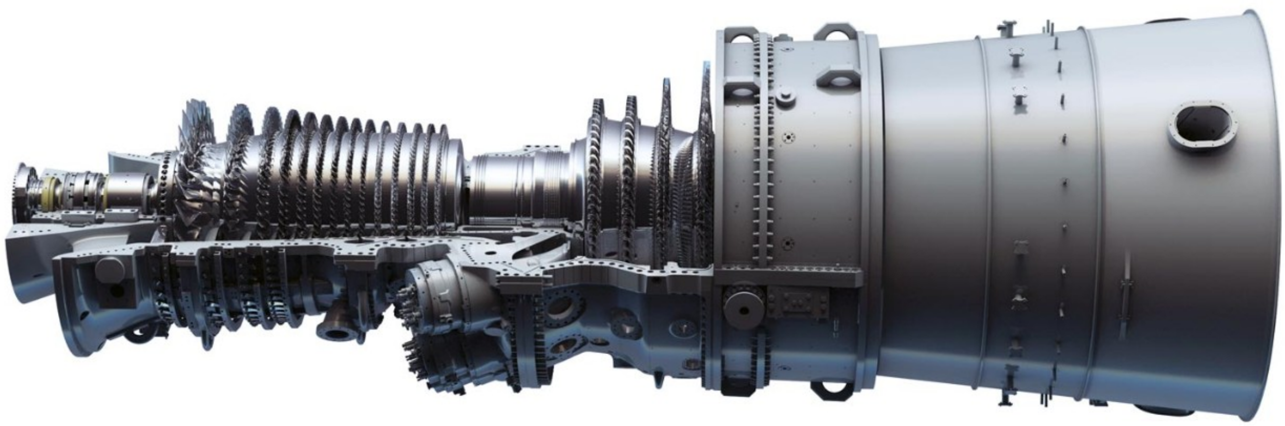
[2] Limits obtained from agency permitting documents when not available in RBLC.

APPENDIX E: VENDOR INFORMATION

(https://powergen.gepower.com)

Power Generation

The alliance that brought Alstom Power and Grid into the GE family has begun. READ M



7HA.01/.02 GAS TURBINE (60 HZ)

GE's 7HA high efficiency, air cooled gas turbine is an industry leader among H-class offerings and is available in two models—the 7HA.01 at 280 MW and the 7HA.02 at 346 MW.

INDUSTRY-LEADING OPERATIONAL FLEXIBILITY

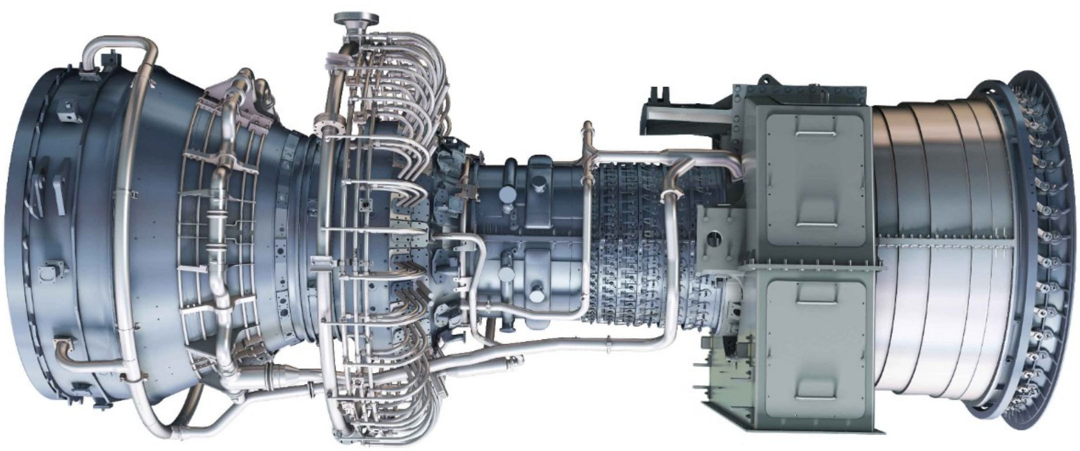
Features a 10-minute ramp-up from start command to full load, and up to 50 MW/min in a 1x1 configuration or 100 MW/min in a 2x1 configuration.

LESS COMPLEX H-CLASS OFFERING

Simpler configuration and modular systems facilitate easier installation with 10,000 fewer man-hours than the 7F.03 gas turbine.

FULL-LOAD VALIDATION

The 2016 testing of the 7HA technology in GE's full-speed, full-load test facility in Greenville, SC, reinforces the impressive performance and robust capabilities of these units.



7HA.01 / 7HA.02

The economies of scale created by the 7HA, combined with its more than 62 percent combined-cycle efficiency, enables the most cost-effective conversion of fuel to electricity to help operators meet increasingly dynamic power demands.

- Streamlined maintenance with quick-removal turbine roof, field-replaceable blades, and 100 percent borescope inspection coverage for all blades
- Simplified dual-fuel system uses less water, eliminates recirculation, and utilizes enhanced liquid purge for improved reliability and dependability
- 14-stage advanced compressor with 3D aerodynamic foils with superfinish, 3 stages of variable stator vanes, and field-replaceable blades
- DLN 2.6+ combustor with axial fuel staging is proven through 45,000 starts and >2 million hours
- Combustor enables improved turndown and greater fuel flexibility
- Reduces need for on-site gas compression; fuel pressure requirements as low as 435 psi/30 bar
- Fuel flexible to accommodate gas and liquid fuels with wide gas variability, including high ethane (shale) gas and liquefied natural gas

FORMER NAMES:
Frame 7H, 7F 7-Series, 7F-7, 7FA.06, FE60

GE's HA gas turbine auxiliary systems are pre-configured, factory assembled and tested modules engineered to reduce field connections, piping, and valves. This translates to a simpler installation that reduces field schedule and installation quality risks while improving overall installation times—up to 25% quicker compared to GE F-class gas turbine enclosures.

Explore the HA's Modular Enclosure → (http://powerpacking.gepower.com)

FEATURED SERVICES

GE empowers you with total lifecycle solutions tailored to your desired outcomes. Our advanced technology and service solutions deliver industry-leading value to your products.

GAS TURBINE PARTS

GAS TURBINE REPAIRS

SERVICE AGREEMENTS

NEW ELECTRIC POWER GENERATION

C15

< Back

- Marketing Content Product Overview Section Overview C15 ATAAC, I-6, 4-Stroke Water-Cooled Diesel
- 320 to 550 ekW, 365 to 550 kVA
- 50 Hz 1500 RPM or 60 Hz 1800 RPM
- 208 to 600 Volts
- For Emergency Standby (ESP), Standby, Prime and Continuous applications

REQUEST A QUOTE

TRUE PROJECT FINANCING

See our Offers

TECHNICAL INFORMATION

FIND YOUR DEALER

COMPARE MODELS

SIZING TOOL

VIEW PRODUCT DOWNLOADS

C15 Diesel Generator Sets

PHOTO **360 VIEW**

SPECIFICATIONS **BENEFITS & FEATURES** **EQUIPMENT** **RELATED PRODUCTS**

OVERVIEW

Producing reliable power from 320 ekW to 500 ekW at 60Hz, our C15 ACERT® diesel generator sets are built for standby and prime applications and built to your power standards. Each are engineered to ISO 8528-5 transient response requirements and designed to accept 100 percent rated load in one step. Our C15 generator sets range from low fuel consumption systems to EPA Tier 4 Interim certification. We plan for the unpredictable, which is why all models are made to meet seismic certification. Our integrated control system, including Cat® UPS, ATS and switchgear, keeps your power constant and keeps you connected to your fleet with on-site and remote monitoring capabilities. Access management and diagnostics tools with our easy to use EMCP 4 control panels, which provide expandable functionality from basic generator set monitoring, control, and protection to full multi gen paralleling. We offer accessories and bolt-on system expansion attachments to help you meet specific power needs. Flexible packaging options work with your spatial restrictions and climate. Even select from UL 2200 and CSA certified packages for added safety.

GENERATOR SET SPECIFICATIONS

UNITS: **US** **METRIC**

Minimum Rating	320 ekW (365 kVA)
Maximum Rating	500 ekW (550 kVA)
Voltage	208 to 600 Volts
Frequency	50 or 60 Hz
Speed	1500 or 1800 RPM

ENGINE SPECIFICATIONS

Engine Model	C15 ATAAC, I-6, 4-Stroke Water-Cooled Diesel

Compression Ratio	16.1:1
Aspiration	Air to Air Aftercooled
Governor Type	Adem™A4
Fuel System	MEUI
Bore	5.4 in
Displacement	927.56 in³
Stroke	6.75 in

Rating Specific Emissions Data - John Deere Power Systems

JOHN DEERE

Nameplate Rating Information

Clarke Model	JU4H-UFAD5G
Power Rating (BHP / kW)	113 / 84
Certified Speed (RPM)	2100

Rating Data

Rating	4045HFC28D	
Certified Power (kW)	101	
Rated Speed	2100	
Vehicle Model Number	Clarke Fire Pump	
Units	g/kW-hr	g/hp-hr
NOx	3.70	2.76
HC	0.17	0.13
NOx + HC	N/A	N/A
Pm	0.15	0.11
CO	1.7	1.3

Certificate Data

Engine Model Year	2015
EPA Family Name	FJDXL04.5119
EPA JD Name	350HAJ
EPA Certificate Number	FJDXL04.5119-003
CARB Executive Order	Not Required
Parent of Family	4045HFG82A
Units	g/kW-hr
NOx	3.36
HC	0.15
NOx + HC	N/A
Pm	0.17
CO	1.3

* The emission data listed is measured from a laboratory test engine according to the test procedures of 40 CFR 89 or 40 CFR 1039, as applicable. The test engine is intended to represent nominal production hardware, and we do not guarantee that every production engine will have identical test results. The family parent data represents multiple ratings and this data may have been collected at a different engine speed and load. Emission results may vary due to engine manufacturing tolerances, engine operating conditions, fuels used, or other conditions beyond our control.

JOHN DEERE

EMISSION CONTROL INFORMATION
DEERE & COMPANY

•This engine complies with US EPA regulations for 2015 stationary emergency diesel engines including fire pumps. •Fuel: Diesel
•Family FJDXL04.5119 •Displ. 4.5L •E.C.S. EM EC SPL DFI TC CAC
•Engine Model 4045HF285H,I,J • 4045HFC28A,B,C,D • 4045HFS82,83
•EPA Power Category: 56 - 130 kW •LOW OR ULTRA-LOW SULFUR FUEL ONLY
CONSTANT SPEED ONLY

R552640 Mfg Date: YYYY, MM

For Engine Service and Parts -- www.JohnDeere.com/dealer

	UNITED STATES ENVIRONMENTAL PROTECTION AGENCY **2015 MODEL YEAR** **CERTIFICATE OF CONFORMITY** **WITH THE CLEAN AIR ACT**	**OFFICE OF TRANSPORTATION** **AND AIR QUALITY** **ANN ARBOR, MICHIGAN 48105**

Certificate Issued To: **Deere & Company** (U.S. Manufacturer or Importer) **Certificate Number: FJDXL04.5119-003**	**Effective Date:** 11/13/2014 **Expiration Date:** 12/31/2015	Byron J. Bunker, Division Director Compliance Division	**Issue Date:** 11/13/2014 **Revision Date:** N/A

Model Year: 2015
Manufacturer Type: Original Engine Manufacturer
Engine Family: FJDXL04.5119

Mobile/Stationary Indicator: Stationary
Emissions Power Category: 75<=kW<130
Fuel Type: Diesel
After Treatment Devices: No After Treatment Devices Installed
Non-after Treatment Devices: Non-standard Non-After Treatment Device Installed, Electronic Control, Smoke Puff Limiter, Engine Design Modification

Pursuant to Section 111 and Section 213 of the Clean Air Act (42 U.S.C. sections 7411 and 7547) and 40 CFR Part 60, and subject to the terms and conditions prescribed in those provisions, this certificate of conformity is hereby issued with respect to the test engines which have been found to conform to applicable requirements and which represent the following engines, by engine family, more fully described in the documentation required by 40 CFR Part 60 and produced in the stated model year.

This certificate of conformity covers only those new compression-ignition engines which conform in all material respects to the design specifications that applied to those engines described in the documentation required by 40 CFR Part 60 and which are produced during the model year stated on this certificate of the said manufacturer, as defined in 40 CFR Part 60.

It is a term of this certificate that the manufacturer shall consent to all inspections described in 40 CFR 1068 and authorized in a warrant or court order. Failure to comply with the requirements of such a warrant or court order may lead to revocation or suspension of this certificate for reasons specified in 40 CFR Part 60. It is also a term of this certificate that this certificate may be revoked or suspended or rendered void *ab initio* for other reasons specified in 40 CFR Part 60.

This certificate does not cover engines sold, offered for sale, or introduced, or delivered for introduction, into commerce in the U.S. prior to the effective date of the certificate.

APPENDIX F: EFSB TESTIMONY OF DANIEL PEACO

COMMONWEALTH OF MASSACHUSETTS
ENERGY FACILITIES SITING BOARD

Petition of NRG Corporation for Approval to	:	EFSB 15-xx
Construct a Bulk Generating Facility in the Town	:	
Of Sandwich	:	

DIRECT TESTIMONY

OF

DANIEL PEACO

ON BEHALF OF THE PETITIONERS

DECEMBER 2, 2015

DOCKET NO. EFSB 15-xx

DIRECT TESTIMONY OF DANIEL PEACO

TABLE OF CONTENTS

ATTACHMENTS

I. Introduction and Summary

Q. Please state your name, position, and business address.

A. My name is Daniel Peaco. I am a Principal Consultant at Daymark Energy Advisors (Daymark).[1] My business address is One Washington Mall, 9th Floor, Boston, Massachusetts 02108.

Q. Please summarize your professional experience and qualifications.

A. I have more than 35 years of a broad set of policy, planning and decision support experience in electric power industry planning. I began my career with electric utilities and, for the past 19 years, have been providing consulting services with our firm. My areas of expertise include integrated resource planning, strategic planning, competitive electric markets, evaluation of generation asset investments, renewable energy policy, transmission planning, competitive procurement and power contracts, and industry restructuring. With respect to the subject of this testimony, my consulting practice has included a number of engagements in which I have provided expert testimony related to energy, economic, and environment assessments of proposed energy facilities siting before the EFSB and other regulatory agencies with siting authority.

I have been employed at Daymark since 1996. I served as President of the firm from 2002 through July of this year. I am currently Chairman of our Board, a position I have held since 2002.

1 Daymark Energy Advisors is the new name of the firm formerly known as La Capra Associates. The name change occurred on November 9, 2015.

Prior to joining Daymark, I held power supply planning positions with Central Maine Power Company (1986-96), Pacific Gas & Electric Company (1981-86), and the Massachusetts Energy Facilities Siting Council (1978–79).

I hold a master's degree in Engineering Sciences from the Thayer School of Engineering at Dartmouth College (1981) and a bachelor's degree in Civil Engineering from the Massachusetts Institute of Technology (1977). A copy of my resume is attached hereto as Attachment DEP-1.

Q. Please summarize Daymark Energy Advisors and its business.

A. Daymark Energy Advisors provides energy planning, market analysis, and regulatory policy consulting and advisory services to support decision making within the electricity and natural gas industries. We serve a broad range of clients across North America, including private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations, and other industry stakeholders.

Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics.

Q. Have you previously testified before the EFSB or other Commissions?

A. Yes. I have appeared before the EFSB in five proceedings. In addition, I have testified on numerous occasions before a significant number of state and provincial regulatory commissions and siting authorities across the US and Canada. A complete listing of my expert witness appearances, including testimony at the Siting Board, is included in Attachment DEP-1.

Q. What is the purpose of your testimony?

A. Canal 3 Development LLC, a subsidy of NRG Energy Inc., is proposing to construct a state-of-the-art, dual-fueled simple cycle electric generating facility known as the Canal Unit 3 Project (Canal 3 or Project) with an in-service date of June 2019. I am offering this testimony to present my analysis of the Project with respect to two issues that will be considered by the Siting Board:

1) Whether the proposed generating facility, on balance, contributes to a reliable, low-cost, diverse regional energy supply with minimal environmental impacts. I offer comparison of the Project to alternative fossil fuel generation technologies and generating units, as required when the proposed project does not meet all applicable Technology Performance Standards (TPS).[2]

2) Whether the plans for the construction of the proposed generation facility are consistent with current health and environmental protection policies of the Commonwealth and with energy policies adopted by the Commonwealth for the specific purpose of guiding decisions of the EFSB. I offer an evaluation of the Project plan for this purpose.[3]

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2 G.L c. 164, § 69J¼; 980 CMR 12.02(2).

3 G.L c. 164, § 69J¼; see also Footprint Power Salem Harbor Development LP, EFSB 12-2 (2013) at 9 (hereinafter referred to as *Footprint Power Decision*).

Q. How is your testimony organized?

A. I first provide a summary of the Project in Section II. In Section III, I provide an overview of the current New England electricity supply outlook, some challenges underlying this outlook, and how the proposed facility assists the Commonwealth and the region in coping with these challenges. Section IV includes my review of alternative technologies and generating units. In Section V, I provide a detailed discussion of how the proposed facility supports the Commonwealth's energy and environmental policies. Section VI contains my overall conclusions.

Q. What are your overall conclusions about the Project's ability to address and satisfy the Siting Board's Alternative Technologies Comparison and Public Policy Consistency standards?

A. I conclude that the project offers significant economic, environmental, and energy policy benefits to Massachusetts ratepayers and is fully consistent with the current health and environmental protection policies of the Commonwealth. The proposed facility will contribute to a reliable, low-cost, diverse regional energy supply that will minimally impact the environment because it compares well to alternative fossil-fuel generating technologies and alternative natural-gas powered generating units. The proposed technology offers advantages over the other alternative technologies on cost, operating flexibility, and compatibility with the region's goals for diversification of the regional energy mix.

II. Project Overview

Q. Please describe your understanding of the Project.

A. The proposed Project[4] is a 350 megawatt[5] (MW) dual-fueled simple cycle electric generating facility with an in-service date of June 2019.

The proposed facility will be located inside of the existing Canal Generating Station property at an existing site in the town of Sandwich in Barnstable County, Massachusetts. The Project is planned for location on approximately 12 acres of previously developed land in the Northern Area of that property (the entire site is 88 acres, with approximately 52 acres of land in the Northern Area and approximately 36 acres of land in the Southern Area).

The existing site is currently developed to support a 1,120 MW dual-fueled steam electric generating plant. The existing generating units connect to the New England power grid, operated by ISO-New England (ISO-NE), at an Eversource switchyard located south of the existing site. The interconnection facilities, natural gas pipelines, and coastal fuel supply mechanisms currently serving the site will serve the Project as currently configured.

The Project is proposed to have one General Electric (GE) H-Frame, simple-cycle gas turbine (GE 7HA.02), or equivalent.[6] This technology will provide quick-start

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4 The information contained in this response is a summary of the Project description contained in the Petition to Construct for Canal Unit 3.

5 As noted in the Petition to Construct, the gross electrical output of the proposed Facility will range from 365 MW at very low ambient temperatures to 330 MW at higher ambient temperatures.

6 The analysis presented in this testimony was prepared in parallel with the development of the Petition prior to final determination of the specific characteristics of the facility as now proposed. I have relied on publicly available information on the proposed turbine technology characteristics that may differ slightly from the Project as proposed in the Petition.

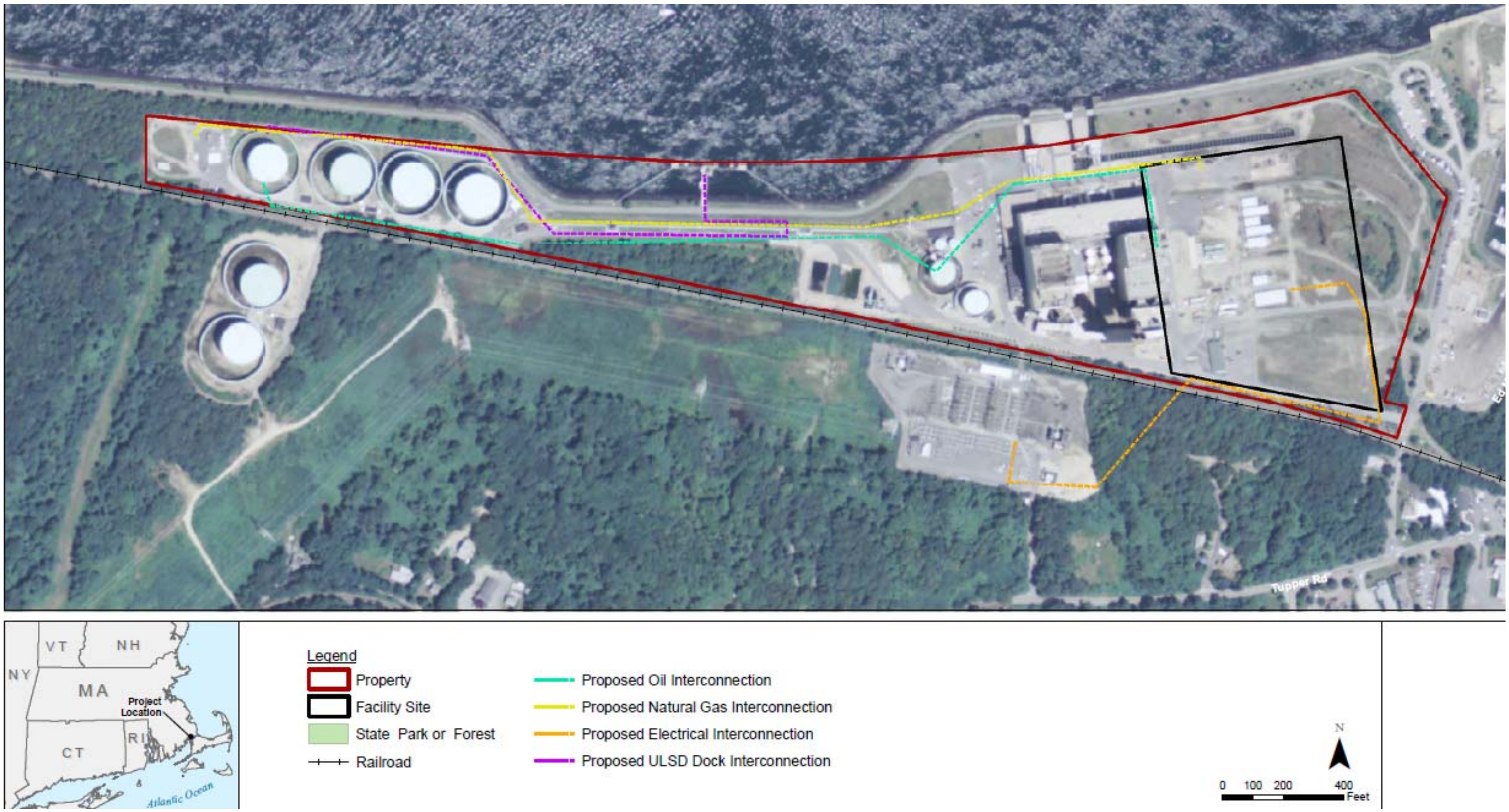
capability, as well as the ability to provide dispatchable and flexible electric power production for New England's bulk power system. Other features of the facility include the capability of full-power attainment within 10 minutes and load-following and cycling capabilities.

The dual-fuel capability of the proposed facility will enable it to operate on natural gas as its principal fuel for up to 4,380 hours per year. The Project will also have the capability to burn ultra-low-sulfur distillate (ULSD) fuel oil for a maximum of 1,440 hours per year.

Figure DEP-1 shows the proposed facility location relative to the existing energy infrastructure at the current Canal site. In this aerial photograph of the current Canal Generating Station property, the entire property is shown. The Northern Area is outlined in red and the proposed facility site within that area is outlined in black. The 12-acres proposed for the site of the Project currently houses warehouse space, two ammonia storage tanks, temporary trailers, and a gravel parking lot.

The aerial photograph has been marked to show routing of pipelines within the site to deliver gas (dotted yellow line) and oil (dotted blue line) to the Project. These interconnections run west-to-east on the current Canal Generating Station property. The current plan is to have oil delivered to the site by a fuel tanker via the Cape Cod Canal. The proposed electrical interconnection (dotted orange line) will connect the project with the existing Eversource switchyard located south of the Northern Area across the railroad tracks. The Project will obtain water from existing water infrastructure.

Figure DEP-1 Project Site Aerial Photograph



III. Overview of Current Electricity System

A. Regional Reliability

Q. Please describe the mechanisms established to ensure power supply reliability in the Commonwealth and New England.

A. ISO-NE manages the reliability of the regional power supply, operates the transmission system, dispatches the generation through it competitive energy and reserves market systems, assures sufficient capacity through its administration of the Forward Capacity Market (FCM), and conducts planning for transmission system development.

The FCM is the primary mechanism to assure that new generating capacity is developed when needed for the overall reliability of the power supply, termed Resource Adequacy. The FCM is referred to as a "forward" market because capacity is bought and sold years in advance. Existing and proposed new capacity resources bid into an annual Forward Capacity Auction (FCA), which is conducted by ISO-NE three years before the June 1 through May 31 capacity commitment period for which the procurement takes place. The market is designed in this way because new power plants, if needed, cannot be built overnight but can reasonably be developed within a three year window.

In each FCA, ISO-NE establishes the Net Installed Capacity Requirement (NICR) based on forecasts of regional peak demand and requirements for installed reserves. The NICR sets the target amount of total capacity to be acquired through the FCA for each period. When existing capacity supplies are not offered in sufficient amounts to clear the market, new capacity resources, such as Canal 3, will enter and clear in the market. Capacity resources that clear the market receive a contract to deliver that capacity.

The capacity market now provides an incentive for capacity additions in excess of NICR. In the most recent FCA (FCA #9), ISO-NE implemented a "sloped demand curve", a mechanism that sets a high price for capacity if the market supplies capacity below NICR and clears at a lower price as the offered capacity exceeds NICR.

ISO-NE establishes zones within the region in each FCA to provide locational incentives when capacity is needed in specific locations. For example, ISO-NE established the Southeastern Massachusetts/Rhode Island (SEMA/RI) zone in the most recently completed FCA based on needs specific to that location. Each zone has the potential to clear at price higher the rest of the FCA, providing incentive for capacity development within such zones. ISO-NE establishes local capacity requirements (called Local Sourcing Requirement or LSR) for each zone, setting the minimum amount of capacity that must be located within the zone to satisfy the resource adequacy and transmission security requirements. The local capacity zones use a vertical demand curve that procures enough local capacity up to the LSR, but does not provide incentives for local capacity in excess of LSR.

Q. Please describe how ISO-NE defines the need for capacity in the region with a demand curve.

A. The FCA #9 demand curve, shown in Figure DEP-2,[7] defines a relationship between quantity of supply and prices to be paid for capacity supplied in that auction.

The NICR, depicted by the vertical red line, is the value that ISO-NE has used in prior auctions to represent the capacity and installed reserves required to meet the one-day-in-ten year reliability standard. The demand curve is developed using two additional requirement levels, one to meet a lower one-day-in-five year standard, and the other to meet a higher one-day-in-eighty-seven year standard, defining a range of about 3,900 MW.[8]

The capacity price at the lower reliability level is set at 160 percent of the net Cost of New Entry (1.6 X net CONE).[9] The net CONE value was set at $11.08/kW-month and the higher price cap was $17.73/kW-month. The price at the higher capacity level is set to $0/kw-Month. Prices for capacity levels at or below the lower one-day-in-five year standard are capped at 1.6 x net CONE. Prices for capacity levels above that standard decline linearly as the supply increases, reaching $0 at the higher reliability standard. The price point at NICR is $12.92/kW-month (nearly 1.2 x next CONE). The price is equal to net CONE at a capacity supply some 400 MW above NICR (depicted with the blue lines in Figure DEP-2).

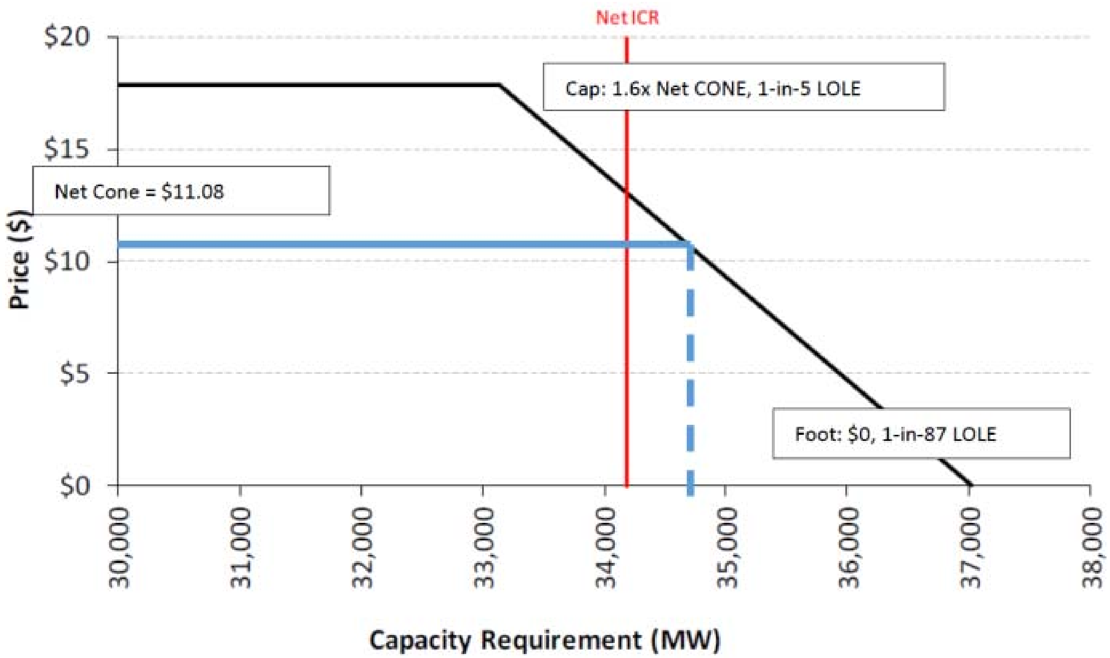
---

7 *ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period*, ISO New England, February 2015. The demand curve for FCA #10 is proposed to be very similar to FCA #9 and is pending review and approval by FERC.

8 The lower value is 33,132 MW, 1,057 MW less than NICR. The higher value is 37,027 MW, 2,838 MW higher than NICR.

9 The Cost of New Entry (CONE) is based on the annual cost of a new combustion turbine. Net CONE is derived by reducing CONE by the amount of estimated revenues from energy and reserve markets.

Figure DEP-2 FCA #9 Demand Curve Results



The demand curve is designed to provide price signals sufficient to allow ISO-NE to procure sufficient capacity to maintain resource adequacy over the long term. The sloped demand curve is set to provide clear incentives (e.g., prices above estimated costs of new entry) for new supply to enter the market whenever total supply is at or below NICR.

Q. What were the results of the most recent FCA?

A. ISO-NE's most recent Forward Capacity Auction, FCA #9, was held in February 2015 for the 2018-2019 planning year. In that auction, ISO-NE procured more than 1,400 MW of new capacity resources in the region, and procured total supply at about 500 MW over the regional NICR[10]. The clearing price for the regional auction was $9.55/kW-month.

[10] FCA #9 procured 34,695 MW of combined new and existing resources. The NICR for FCA #9 is 34,189 MW. See: http://www.iso-ne.com/static-assets/documents/2015/02/fca9_initialresults_final_02042015.pdf

The FCA #9 did not secure sufficient capacity to meet the LSR for the SEMA/RI sub-region. The local shortage result triggered special pricing rules in SEMA/RI. All new resources in the SEMA/RI zone received a price of $17.73 kW-month, while all existing resources received a capacity payment of $11.08 kW-month. Ratepayers in SEMA will have a higher capacity charge than ratepayers in the Northeastern and Western Massachusetts zones that cleared at a price of $9.55 kW-month for the 2018-2019 planning year.[11]

Q. What is your assessment of the need for new capacity in the region?

A. There is a need for new capacity in the region as defined by the FCM demand curve for capacity. The need for capacity is also documented in ISO-NE's recent planning studies.

The FCA #9 demand curve and results provide a good way to illustrate that need assuming the regional demand curve is similar in the next auction.[12] If all capacity that cleared FCA #9 remains in the market for FCA #10, capacity obligations total 544 MW more than NICR. In this hypothetical example, the market would clear at a price similar to FCA #9.

However, recently, owners of the Pilgrim Nuclear Power Station (Pilgrim Station) located in Plymouth, Massachusetts, has also announced that Pilgrim Station will close no later than June 2019,[13] meaning nearly 700 MW of the FCA #9 capacity will not be

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11 *Id.*

12 ISO-NE has recently filed a proposal to FERC recommending an NICR for FCA #10 of 34,151 MW, differing from the FCA #9 value by only 38 MW. The parameters of FCA #10 are subject to change as FERC reviews that proposal.

13 http://www.bostonglobe.com/metro/2015/10/13/entergy-close-pilgrim-nuclear-power-station-nuclear-power-plant-that-opened/fNeR4RT1BowMrFApb7DqQO/story.html?s_campaign=8315

available in FCA #10. The remaining FCA #9 capacity resource obligations are less than NICR by about 140 MW.

Continuing with my example, assume Pilgrim's capacity is removed and no other FCA #9 capacity leaves the market. If no new capacity enters the market, the supply will be approximately 140 MW below NICR and the market price would be more than 120 percent of CONE. That is a price signal well above the price where FCA #9 new entrants cleared the market.

Hence, the fact that existing resources total less than net NICR should provide a signal to project developers, such as NRG, to offer capacity into the auction. The existence of viable capacity supply offers, whether they clear the market and are selected, is a key requirement for the existing market structure to be competitive and cost effective for ratepayers.

If the supply deficiency increases, that is, other existing capacity leaves the market along with Pilgrim Station, the price could increase to as much as 160 percent of net CONE, the price cap.

The need for new capacity is also reflected in ISO-NE's 2015 Regional System Plan (RSP). In that report, ISO-NE stated that it is concerned that "*[t]he region is vulnerable to additional resource retirements that would advance the need for additional system resources. Studies of expected system conditions show that developing new resources in the combined NEMA/SEMA/RI area would provide the greatest reliability benefit*." ISO-NE further states that "*[a] market resource alternative study for the SEMA/RI area identified a need for approximately 1,540 MW of resources (1,495 MW of generation and 45 MW of demand resources spread across nine locations in SEMA/RI). The addition of* *these resources would remove many of the thermal constraints identified in the SEMA/RI transmission needs assessments."*[14]

Q. What is the current power supply reliability outlook for New England and the potential for other capacity to leave the market?

A. The supply of capacity in the region has recently transitioned from a period of surplus capacity to one with short supply and the need for new capacity. The reliability of the current supply mix in the region is also challenged due to the advanced age of many of the existing generating assets and the extensive reliance on natural gas-fired power stations during peak load periods.

ISO-NE has identified the potential for power plant retirements as one of the "key challenges" to the grid and reliable electric supply in the region.[15] According to the 2015 ISO-NE Regional Electricity Outlook (REO), over 3,500 MW of mostly coal and oil-powered generation is scheduled to retire by 2018, and ISO-NE has identified an additional 6,000 MW comprising of older facilities (> 40 years of age) that are at risk of retirement.[16] Both lower natural gas prices in the region associated with the development of shale gas supplies and environmental regulations, such as the US EPA's Clean Power Plan rules, add to the retirement pressures on aging coal and oil-fired generating stations.

Demand Resources (DR) also play a role in the regional supply of capacity. DR provided nearly 2800 MW[17] (650 MW Active and 2160 MW Passive) of capacity resources in

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[14]. "2015 Regional System Plan." ISO-NE, November 5, 2015, pages 6-7.

[15] http://www.iso-ne.com/about/what-we-do/todays-challenges

[16] "2015 Regional Electricity Outlook." ISO-NE, January 2015, page 22. http://www.iso-ne.com/static-assets/documents/2015/02/2015_reo.pdf

[17] "2015 Regional System Plan", page 55.

FCA #9, which was one of the lowest since the inception of the market[18]. The contraction of demand response in the past has been due primarily to the establishment of more stringent telemetry requirements and potential higher risk in participating in the energy and reserves markets to comply with FERC Order 745.[19] The future role of demand response in wholesale markets is the subject of an appeal currently pending before the U.S. Supreme Court[20] regarding a lower court's ruling overturning FERC rules[21] on demand response. In the event that the lower court ruling stands, this would restrict DR participation in the energy markets and, potentially the capacity and ancillary service markets, as well.[22]

Q. Please describe how the current proposed Project could impact market conditions and FCA clearing prices.

A. The procurement of the proposed NRG facility in the upcoming FCA will have positive benefits for the region in terms of lower capacity prices.

I have provided an analysis to illustrate this effect and provide an approximate magnitude of the savings. The analysis shows the impact on the capacity prices resulting from the clearing of the Project compared to an auction conducted without the Project, all else being equal.

[18] The Active Demand Response has been reduced from 2000 MW in 2015/2016 Commitment Period (CP) to 650 MW in 2018/2019 CP.

[19] Order 745, if implemented, would require new rules on integration of DR in energy, capacity and ancillary services markets.

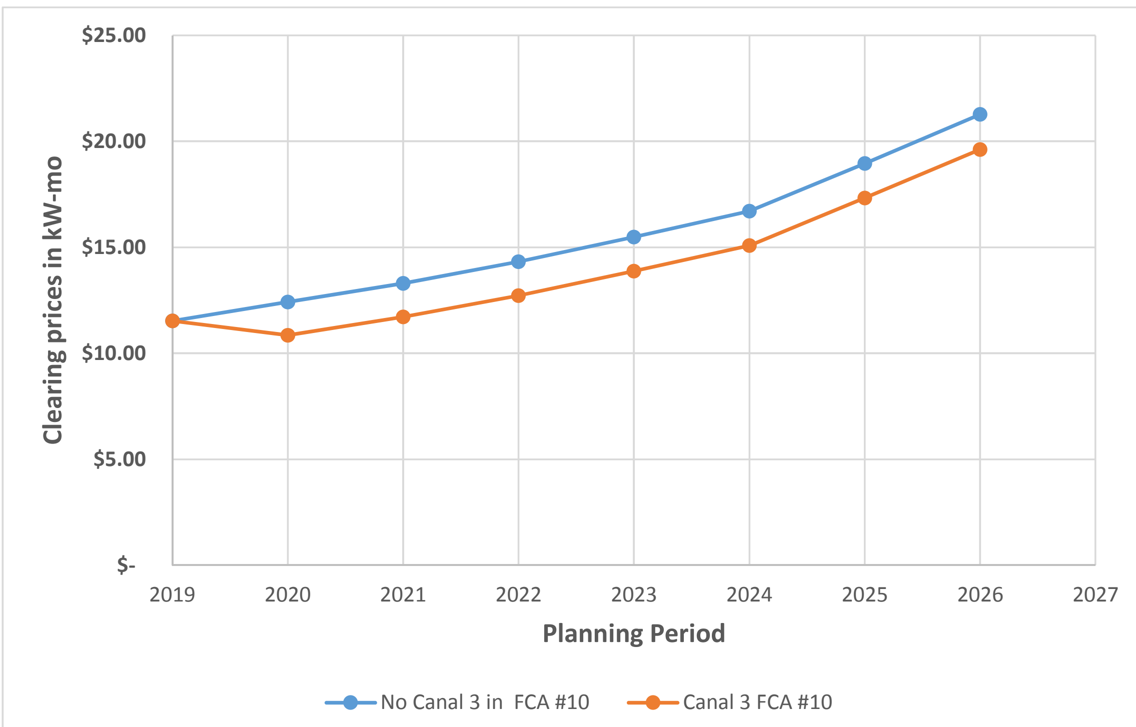
[20] Federal Energy Regulatory Commission v. Electric Power Supply Association, et al., U.S. Supreme Court case No. 14-840.

[21] *Demand Response Compensation in Organized Wholesale Energy Markets*, FERC Order 745, issued March 15, 2011.

[22] *Contingency Plan Addressing the Potential Loss of FERC Jurisdiction over Demand Response*, ISO New England, April 17, 2015 at 2-3.

In this illustration, the Project clears FCA #10 as the marginal resource at a price above Net Cone.[23] The benefits of the new entry will be realized in the subsequent auctions where the unit would then be operating under a capacity supply obligation and would be considered a price taker (and thus offer at zero). The alternative -- No Canal 3 in FCA #10 -- scenario depicts how the capacity prices will develop in the next capacity auctions, as determined by our capacity market model. The Canal 3 in FCA #10 case depicts a scenario that includes the same set of assumptions as in the status quo case but with the addition of the Project clearing in the upcoming FCA #10 Auction as the marginal resource.

Figure DEP-3 Capacity Market Prices With and Without the Proposed Facility



[23] The analysis assumes existing FCA #9 supplies remain in the market and the addition of the Project. Additional offers could enter the market and cause the market to clear at a different point on the demand curve, resulting in lower prices. Conversely, if existing suppliers leave the market, the prices could be higher.

Based on this analysis, the new generating facility would reduce the capacity market price by $1.5 kW-month on average for the next four capacity auctions and extends the need for new resources to 2024.

B. Regional Natural Gas Supply and Fuel Mix

Q. Please explain the challenges ISO-NE is experiencing with gas supply for electric generation.

A. Over the last several years, natural gas became the most dominant fuel source in New England. The majority of new power supply capacity built since the late 1990s have been natural gas combined cycle units. Gas usage in other sectors of the economy is growing, as well. The gas infrastructure development has not kept pace with New England's growing need for natural gas supply. In the 2015 REO, ISO-NE states that "[t]he performance of the largest and most flexible portion of the region's generating fleet is being weakened by insufficient natural gas pipeline and LNG storage in the region".[24] In this circumstance, ISO-NE has identified several factors which affect the ability of natural gas-fired units to obtain the fuel supply they require to operate, including inadequate infrastructure, interruptible fuel arrangements, expensive alternatives, out-of-sync markets, and limited fuel storage.

Owners of natural gas-fired generating units typically procure their gas supply on an interruptible or non-firm basis. The demands of firm transportation customers are met as first priority, typically residential and commercial customers served by local gas distribution companies (LDCs). When demand exceeds the supply capacity, spot prices

[24] Regional Electricity Outlook, page 14.

increase and some interruptible customers are not served. As more residential and commercial businesses convert to natural gas from oil, due to the less expensive regional gas prices, there is potential for further restrictions on interruptible customers.[25]

Q. Please explain the actions being taken to address these concerns with respect to gas supply for electric generation.

A. In response to the natural gas supply issues in New England, ISO-NE is offering incentives for dual-fuel technology investment and incremental liquefied natural gas (LNG) storage. This is being done through its winter reliability program and the Pay-for-Performance (PfP) incentives in the FCM. ISO-NE has also increased its communications with gas pipeline operators to verify that the fuel requirements for natural gas generators scheduled to run will be able to be fulfilled.[26]

The ISO-NE winter reliability program of 2014/15 was a special program offered to mitigate the reliability risks associated with interruptible gas supply to generators. This program is paying competitively selected oil-fired generators, dual-fuel generators, LNG operators, and demand resources to take actions to securing fuel inventory and fuel-switching capability. Participants were compensated for any unused fuel inventory and were subject to nonperformance charges. The payments in this program were outside of the market systems that ISO-NE administers.[27]

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25 Regional Electricity Outlook, page 15.

26 FERC, Communication of Operational Information between Natural Gas Pipelines and Electric Transmission Operators, Order No. 787, final rule (November 15, 2013), http://www.ferc.gov/CalendarFiles/20131115164637-RM13-17-000.pdf.

27 Regional Electricity Outlook, page 35.

In addition, the 2014/15 winter reliability program included permanent improvements designed to aid dual-fuel units. First, on days when oil and natural gas prices approached convergence, ISO-NE provided added flexibility on fuel switching by eliminating the prior requirement that dual-fuel generation units prove they actually burned the higher-priced fuel included in their bid price. Second, ISO-NE established the capability to continue its program to test the fuel-switching ability of dual-fueled units and provided for compensating the units for the cost of the tests.[28]

ISO-NE has also developed changes to its Forward Capacity Market rules to address these issues within the market system in the future. The PFP rules were implemented in FCA #9 for resources that will provide capacity in 2018 and in subsequent years. ISO-NE implemented PfP to provide stronger financial incentives to capacity suppliers to perform when called on during periods of system stress and make investments to ensure performance. As a result of PfP rules, ISO-NE expects generators to respond by firming up their fuel supply and give the market cues that could lead to possible infrastructure development of gas pipelines or oil storage facilities. ISO-NE's ultimate goal with the PfP rules is to create "an efficient and effective way to promote investments necessary to improve performance, to provide high-performing resources a stable revenue stream to maintain their viability, and to ensure continued predictable capacity prices and long-term reliability for consumers".[29]

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28 *Id.*

29 Regional Electricity Outlook, page 37.

ISO-NE's out-of-market measures in the near term[30] and the more permanent market solutions implemented in the FCM provide clear direction to capacity resources that dual-fueled capability is needed in the system.

Q. Please explain the current capacity resources mix by fuel type in ISO-NE.

A. Figure DEP-4 shows the current peak winter supply portfolio from the 2014-2015 planning year for ISO-NE, presented on a capacity (MW) basis.[31]

As previously described, natural gas has become the predominant fuel in the New England area. In the 2014/15 resource mix in ISO-NE, single-fuel natural gas generation units (CCs and CTs) constitute approximately 35 percent of the regional capacity mix. Dual-fuel natural gas/oil generation units (Dual Fuel, Dual Fuel CC and Dual Fuel CT) make up and additional 19 percent of the capacity mix. In aggregate, as much as 54 percent of the regional winter capacity could be derived from natural gas fired resources.

The remaining 46 percent of the capacity mix is diversified among other fuel types. Hydropower, nuclear, coal and oil units together provide 41 percent. The remaining 5 percent is provided by land-fill gas, wind and solar.

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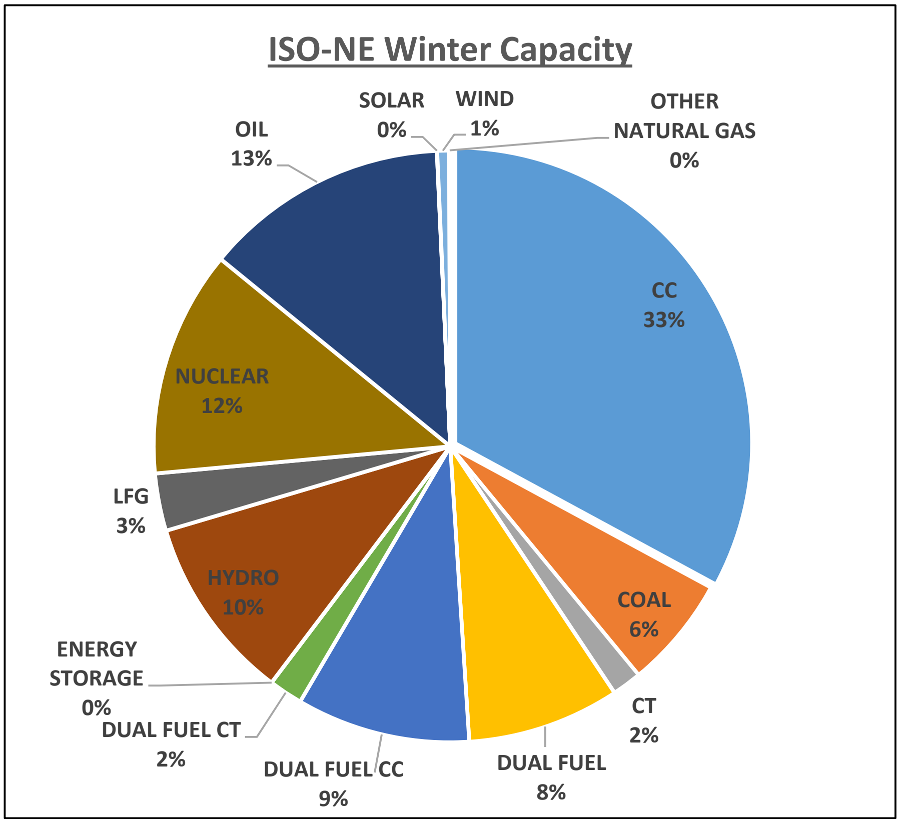
30 SO-NE filed, and FERC approved, Winter Reliability programs nearly identical to the winter 2014/2015 program through the winter of 2017/2018. These programs cover the winter periods prior to the start of PfP where it is expected that resource owners will implement fuel strategies, such as dual fuel capability, to meet their capacity delivery obligations. http://iso-ne.com/static-assets/documents/2015/09/er15-2208-000.pdf.

31 The 2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report) for ISO New England.

Figure DEP-4 ISO-NE Winter Supply % of Total MW, 2014-15



Q. Please explain the current outlook for changes to the capacity resources mix based on fuel type for the year 2019, the year when Canal 3 is proposed to be in-service.

A. Overall, the total generating capacity in the market will be lower by more than 1,700 MW. Major generation retirements totaling 3,456 MW[32] are expected by mid-2019. Offsetting those retirements will be the addition of 1,684 MW of new generation capacity selected in ISO-NE's FCA #8 and FCA #9.[33] These retirements and additions are presented in Table DEP-1.

32 ISO New England Status of Non-Price Retirement Requests, Excel Spreadsheet, October 13, 2015. http://www.iso-ne.com/system-planning/resource-planning/nonprice-retirement.

33 ISO-NE Forward Capacity Auction 2018-2019 Obligations Excel Spreadsheet. http://www.iso-ne.com/markets-operations/markets/forward-capacity-market. ISO-NE press release for FCA #9. http://www.iso-ne.com/static-assets/documents/2015/02/fca9_initialresults_final_02042015.pdf.

The capacity mix will be less fuel diverse in 2019 as a result of these changes. The Coal and Nuclear categories will be significantly less than depicted in Figure DEP-4. The new capacity additions will increase New England's reliance on units capable of using natural gas. Most of this added capacity has dual fuel capability. The increase in retirements from oil-fired, coal-fired, and nuclear generation reduces the fuel diversity in the capacity mix, increases the reliance on units capable of using natural gas, and increases the need for dual fuel capable units in New England.

Q. What is the longer term outlook for changes to the capacity resources mix based on fuel type?

The ISO-NE interconnection queue provides information on the types of generation projects that are being planned in the region.[34] Wind projects in the queue total 3,670 MW (nameplate), representing roughly 1,000 MW of FCM-qualifying MW in the queue.[35] Natural gas/oil dual-fueled unit projects totaling 4,314 MW account for 41 percent of the queue MW (nameplate) and over 80 percent of the new FCM-qualifying MW in the queue. It is clear that sources of new capacity seeking to enter the market are predominantly natural gas/oil dual-fuel.

34 Nov. 1, 2015 http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

35 Wind Resources typically qualify about 25 percent of their nameplate capacity for FCA capacity, determined by taking the FCA #9 winter qualification MW for each wind resource and dividing them by their nameplate capacities. An average was taken across all wind resources to determine approximately what percentage of the nameplate capacity in the FCM wind resources generally qualify.

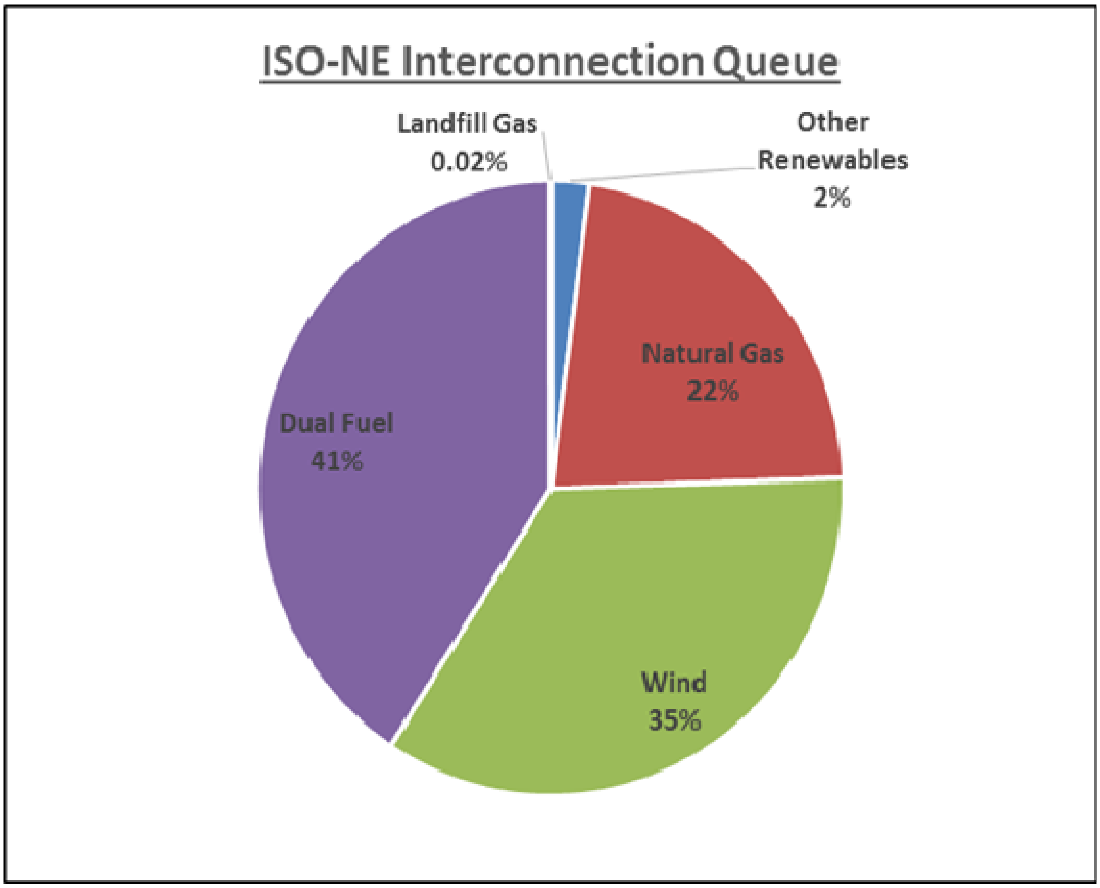
Table DEP-1 Major Retirements and Additions between 2014/2015 and 2018/2019

Retirements	**Fuel Type**	**Winter Capacity (MW)**	**Figure DEP-4 Category**
Vermont Yankee	Nuclear	642	Nuclear
Norwalk Harbor Units 1, 2, & 10	Oil	353	Oil
Brayton Point Units 1 – 4	Coal	1,606	Coal
Mount Tom	Coal	147	Coal
Pilgrim Station	Nuclear	708	Nuclear
	Retirements Total	**3,456 MW**	
Additions			
Footprint Power	Dual Fuel	674	Dual Fuel CC
Wallingford	Natural Gas	90	CT
Medway	Dual Fuel	195	Dual Fuel CT
CVP Towantic	Dual Fuel	725	Dual Fuel CC
	Additions Total	**1,684 MW**	
	Net Change in Winter Capacity	**(1,772) MW**	

With respect to contributions to the capacity mix, wind resources are able to qualify only a fraction of their nameplate capacity in the FCM, making the potential contribution to the capacity mix less than natural gas units.

Figure DEP-5 ISO-NE Interconnection Generation Requests

(% of Total Net New MW)



Q. Please explain the current and future energy mix in New England.

A. In 2014, natural gas and nuclear generation were the largest sources of electrical energy in the region at 43 percent and 34 percent, respectively, and 77 percent combined.[36]

In terms of market pricing, it is also important to consider the mix of resources that are "on the margin" and set the market clearing prices in the ISO-NE energy market. In 2014, the ISO-NE internal market monitor reported that natural gas was the marginal fuel 70 percent of the time during both unconstrained and constrained pricing intervals. After natural gas, the fuels on the margin the most in 2014 were coal at 8 percent and pumped storage at 7 percent.[37]

In summary, natural gas is fueling 43 percent of the energy supply in the market and setting the market energy prices 70 percent of the time. This level of reliance on natural gas gives rise to the concerns raised by ISO-NE on reliability of supply. It also is a very important factor in the region's electric energy supply cost and exposure to the uncertainties in the gas supply infrastructure.

Q. Please describe the outlook for the future energy mix in New England.

A. We have prepared a baseline projection of the New England energy market using our regional market modelling system.[38] In this analysis, we include load forecast and capacity and energy resources consistent with ISO-NE planning assumptions and assume

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36 *2015 Regional System Plan*. ISO-NE, November 5, 2015, page 9.

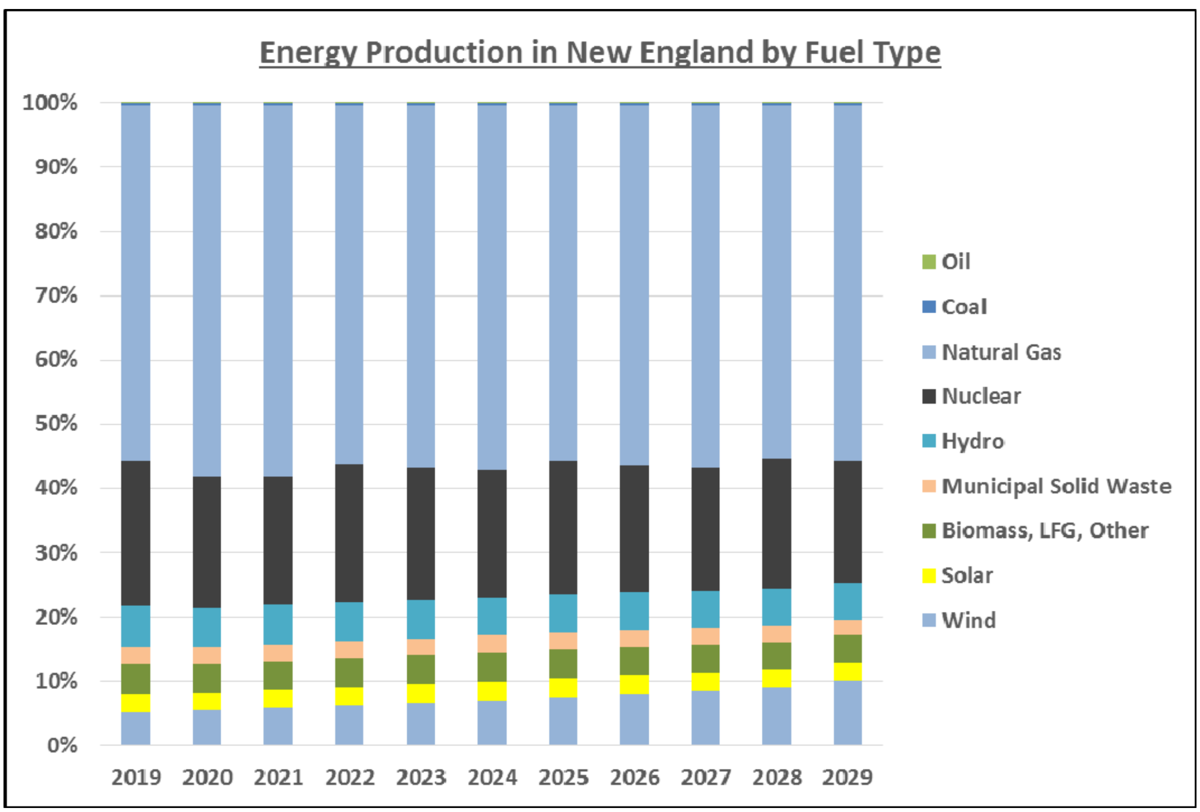
37 ISO-NE Internal Market Monitor Report 2014, page 39. http://www.iso-ne.com/static_assets/documents/2015/05/2014-amr.pdf.

38 We prepared this forecast with our regional market simulation model using the AURORAxmp® software.

the region complies with established RPS policies. Attachment DEP-2 to this testimony more fully documents the assumptions in this analysis.

In the period 2019 to 2029, our baseline analysis indicates that natural gas will increase to approximately 55 percent of the total electric energy production in New England, compared to 43 percent in 2014. That analysis also shows nuclear to produce 20 percent of the energy through that period, a decline from the 34 percent in 2014. The combined gas and nuclear total of 75 percent matches the 2014 result, with additional natural gas-fired generation picking up the production lost from the retirements of Pilgrim Station and Vermont Yankee. The baseline projection of energy mix is displayed in Figure DEP-6-6.

Figure DEP-6 ISO-NE Energy Mix 2019 – 2029



Q. Please summarize the regional natural gas supply and fuel mix issues in the region.

A. The region is very dependent on natural gas as a fuel for power supply. This raises a number of reliability, energy security, and energy price volatility issues. ISO-NE and others in the region have identified these issues as significant and actions are being taken to mitigate the adverse consequences.

Among the actions taken is to provide incentives for capacity resources that are capable of burning natural gas to have dual-fuel capability. That capability is an important attribute for capacity additions to the system in the context of the current and anticipated future reliance on natural gas generation that I have described above.

IV. Alternative Technologies Comparison

Q. Please explain the standard of review of the Siting Board when considering NRG's proposal in relation to an alternative technologies comparison.

A. The proposed Project will have one or more emissions in excess of the emissions standards in the EFSB's Technology Performance Standards (TPS).[39] Thus, the Project does not qualify for the streamlined review used in Petitions to Construct where emissions from proposed facilities fall below TPS limits.

In this circumstance, a key part of the Siting Board review of an application to construct a new generating facility in the Commonwealth is to compare the technology of the proposed facility to other fossil fuel generating technologies to ensure that "on balance

[39] 980 CMR 12.00: Technology Performance Standards.

[it] contributes to a reliable, low-cost, diverse regional energy supply with minimal environmental impacts".[40]

Q. Please explain how your testimony addresses the Project's requirements to provide additional information on generating technologies under the TPS.

A. I am providing an analysis comparing the proposed Project to other fossil fuel generating technologies with respect to reliability, environmental impacts, costs, and diversity. This information is required by Section 69J¼ of Chapter 164 and 980 CMR 12.02(2).

Q. What alternative technologies did you select and how did you compare them to the proposed Project?

A. I chose to compare the proposed Project to other dual-fuel technologies that primarily run on natural gas and could provide similar benefits to the electric system through a different combination of attributes including quick-start and load-following capabilities.

The key cost and performance factors reviewed in the analysis include the following: capital costs; fixed and variable O&M costs; levelized cost of energy; quick-start ability; forced and unforced outage rates; air emissions; and production efficiency (heat rate).

Specifically, I compared the proposed Canal 3 technology[41], GE 7HA.02, to a natural gas peaking technology, the GE LMS100, and a natural gas combined cycle technology, the Siemens SGT6-5000F 2x2x1.[42]

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[40] G.L. c. 164, § 69J¼.

[41] The Canal 3 technology cost assumptions are costs typical of GE H-Class technology from published sources. The analysis presented in this testimony was prepared in parallel with the development of the Petition, prior to final determination of the specific characteristics of the facility as now proposed. The publicly available information on the proposed turbine technology characteristics may differ slightly from the Project as proposed in the Petition.

[42] The Siemens SGT6-5000F is a combined cycle that consists of two combustion turbine generators (CTGs), two heat recovery steam generators (HRSGs), and one steam turbine generator in a multi-shaft 2x2x1 configuration.

Q. Please explain how you selected the technologies to compare to the proposed Project.

A. In considering which fossil fuel generating technologies to compare to the proposed Project, I reviewed the current ISO-NE interconnection queue, current EPA and Massachusetts GHG emission standards, recent units built in ISO-NE and surrounding regional transmission operators (RTOs), and capital cost comparisons from the Environmental Information Agency 2015 Annual Energy Outlook (EIA 2015 AEO). The ISO-NE interconnection queue,[43] as of November 1, 2015, has no simple-cycle exclusively oil-fired generating technologies or advanced coal-fired generating technologies proposed and I did not find any planned or proposed construction of an oil-only peaking unit anywhere else in the country.

The EIA 2015 AEO capital cost data indicates the advanced coal-fired technologies had higher capital costs[44] and faced more financial and economic challenges compared to advanced combustion turbines and advanced dual-fuel combined cycles. These financial and economic challenges are largely driven by increased emphasis on reducing environmental impacts.

Under Section 111(b) of the EPA's Clean Air Act, the EPA is proposing standards[45] aimed at limiting carbon pollution from coal and natural gas power plants. In Massachusetts, the GWSA created a framework for reducing heat-trapping emissions by

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43 Nov. 1, 2015. http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue

44 The EIA's 2015 AEO total overnight capital costs in 2013 dollars per kilowatt ("$/kW"), not including financing costs, for new coal-fired technologies were the following: $2,917 per kW for High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization technology; $3,727 per kW for Integrated Coal-Gasification Combined Cycle; and $6,492 for Integrated Coal-Gasification Combined Cycle with Carbon Sequestration. http://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf

45 http://www2.epa.gov/cleanpowerplan/carbon-pollution-standards-new-modified-and-reconstructed-power-plants

25 percent by 2020 and an 80 percent reduction by 2050. These standards make the cost of constructing an advanced coal-fired plant or simple-cycle exclusively oil-fired generating technology even higher than natural gas-fired units and, therefore, even less economical in the New England electricity market by comparison.

The EIA 2015 AEO does not include any cost information for simple-cycle exclusively oil-fired generating technologies.

There are a number of attributes that are common among the selected technologies. All comparison technologies have dual-fuel capability, use natural gas as the primary fuel (oil as a backup), have on-site fuel storage capability, contribute towards the resource adequacy in the region, and assist in renewable resource integration.

Q. Please explain how you considered other fossil fuel generating options.

A. I have limited the comparative analysis of fossil fueled technologies to those mentioned above, concluding that coal-fired or exclusively oil-fired options would not be feasible alternatives.

First, there are no coal-fired or exclusively oil-fired generation options in the ISO-NE interconnection queue. This is an indication that none of the active market participants are considering either fuel type for development in the market today.

Second, coal-fired power plants face a number of cost, technology, and environmental hurdles in New England. In the current market environment, coal delivered to New England does not offer a price advantage over natural gas and the capital costs for new coal generation with requisite emissions control technology far exceeds any of the natural gas fired options. A coal facility would also have higher GHG emission and, thus, higher costs to secure emissions allowances and to comply with the requirements of the new Clean Power Plan. Further, it is unclear whether a coal plant could be sited and permitted at any location within New England.

Technologies designed to operate exclusively on oil face environmental hurdles for permitting in New England. The three technologies compared in my analysis are capable of running exclusively on distillate oil, though such units are challenged to obtain air emissions permits that would allow such operations. Technologies that would utilize heavier grades of oil would face additional permitting challenges.

Q. Please summarize the basis for the technologies you have included in your comparative analysis.

A. I have selected the two combustion turbine alternatives and a combined cycle alternative for comparison, representing the fossil fueled generating technologies that are most consistent with the reliability, economic and environmental requirements in the region at this time. I have assumed each of these options will have the capability to operate on natural gas and distillate oil, providing dual-fuel capability needed for reliability. The technologies are consistent with those represented in the ISO-NE interconnection queue. Alternative technologies that rely exclusively in oil or that use coal were excluded from the analysis based on the poorer environmental performance and associated challenges to be sited and permitted in the region.

Q. Please explain the results of the comparison of Canal 3 to the other fossil fuel generating technologies regarding reliability.

A. Figure DEP-7 presents a performance comparison of the comparative technologies. The technologies offer similar reliability and operating characteristics, reliable capacity for resource adequacy, highly flexible operating characteristics, and dual-fuel capability.

The Canal 3 technology has a better ramp rate (MW/min) on start-up than the other technologies. The GE LMS100 and Siemens SGT6-5000F, like Canal 3, have fast ramping speeds to full load and can provide operational flexibility. However, the Canal 3 unit has the ability to achieve higher levels of generation output in a comparable timeframe. The quick start and fast ramping ability to full load, as well as the load following capabilities of Canal 3 can provide ISO-NE with voltage support and frequency management.

In addition, Canal 3 is equipped with automatic generation control (AGC) that will enable it to receive automatic dispatch signals from the system operator, which enables a fast response time, in the event the system experiences unexpected losses of load, generation, or transmission.

These three technologies also have comparable outage rates and are dual-fuel capable, with on-site fuel storage as a possibility. The dual-fuel capability and the ability of Canal 3, and these other technologies, to have on-site oil storage will enable it to provide operational reliability support to the New England power system, especially during the winter months when natural gas availability may be constrained. The system operator will therefore be able to dispatch Canal 3, when needed, at times when other units may not be available due to the potential limited availability of natural gas and their lack of fuel switching flexibility.

The major differences between the two peaking units and the combined cycle unit are the longer construction period for the combined cycle unit, due the unit's comparative complexity, and the ramping ability of the combined cycle, due to the size of the unit.

Q. Please explain the results of the comparison of the proposed Canal 3 technology to the other fossil fuel generating technologies with respect to environmental impacts.

A. In Figure DEP-8, the environmental impacts of the three technologies are compared. All three technologies have similar methods of cooling and similar pollutants that are by-products.

Canal 3 and the GE LMS100 have higher CO_2 emission rates than the Siemens SGT6-5000F, which is due to the higher heat rates of the natural gas peaking technologies. Canal 3 and the GE LMS100 are comparable in terms of CO_2 emission rates. Actual CO_2 emissions will be determined by hours of operations of each unit. The new combustion turbine options provide an option to reduce the CO_2 emissions of the system peaking resources in a system that does not require additional fossil-fired intermediate or base load energy. The combined cycle provides an option to reduce the CO_2 emissions in a system that utilizes such units at high capacity factors. See Section V for further analysis of this comparison.

The Siemens SGT-5000F combined cycle unit requires a larger footprint due the complexity and size of the technology.

When comparing the two peaking units to current peaking units and the combined cycle to current combined cycles, all three technologies will have lower heat rates than many of the existing, operating fossil fuel generating units, meaning higher efficiency, and lower variable O&M costs. These attributes will lead to these units being dispatched ahead of existing fossil fuel units, which generally are less efficient and have higher variable O&M costs. Furthermore, in New England the marginal energy resources tend to be fossil fuel units, which are less efficient than the technologies described in Figure DEP-8. Since the natural gas-fired combustion turbines and combined cycle units are more efficient and will replace the less efficient fossil fuel units, the result will be less combusted fuel and lower air emissions.

Q. Please explain the results of the comparison of Canal 3 to the other fossil fuel generating technologies with respect to costs.

A. In Figure DEP-9, the capital, fixed O&M, and variable O&M costs are compared among the three technologies. The estimated overnight capital costs ($/kW) and fixed O&M costs of the Canal 3 technology gives that technology an advantage over the GE LMS100 and Siemens SGT6-5000F. It is important to note that the overnight capital costs ($/kW) include assumptions on interconnection and fuel supply infrastructure.[46] All three fossil fuel generating technologies have comparable estimated variable O&M costs.

[46] The proposed Project does not require interconnection and fuel supply infrastructure due to its proximity to existing gas and electric infrastructure. The comparative analysis includes those costs for each technology to provide a consistent comparison of the technology types.

Q. Please explain the conclusions made from the comparison of Canal 3 to the other fossil fuel generating technologies with respect to the enhancement of New England's energy mix and prevention of over reliance on one or more fuel sources.

A. Each of the three technologies included in my comparison were evaluated assuming dual fuel capability with natural gas as the primary fuel and distillate as the alternative fuel. This characteristic is critical to the region at this time, as I have discussed in Section III(B) of my testimony.

The region is currently significantly dependent on natural gas fired generation in its overall energy mix, as I have described in Section III(B). The region has a substantial fleet of combined cycle facilities that produce much of the natural gas-fired energy in the regional mix. By comparison, there are very few new, efficient combustion turbines in the region. The combustion turbine technology choice provides a diversification of technologies that serve the peaking requirements of the system. Looking forward, the efficiency and operating flexibility attributes of the combustion turbine technology will become increasingly important to the system supply mix if the Commonwealth and the region increases reliance on renewable energy resources and/or Canadian imports to achieve the goals of the Global Warming Solutions Act and related greenhouse gas emissions polices in the region (See Section V for further discussion of this issue).

The proposed Canal 3 technology offers diversity advantages over the LMS 100 due to the higher ramp rate and lower turn-down minimum. A diverse mix of operating flexibility characteristics will be important in the New England mix going forward.

Q. Please explain the conclusions made from the comparison of Canal 3 to the other fossil fuel generating technologies regarding reliability, environmental performance, and costs.

A. The proposed Canal 3 technology offers cost installed cost advantages over both of the alternatives, both from the cost of the technology and the advantages associated with the use of existing infrastructure at the existing site.

It also offers the quickest ramping rate and, in all other respects, comparable attributes regarding reliability and operability.

The combined-cycle technology offers a lower emissions rate, though it would be used to operate at higher overall capacity factors.

The proposed Canal 3 technology offers advantages to the diversity of supply in the region, with advantages of dual-fuel capability, and compatibility with the region's longer term goals to reduce overall dependence on natural gas through a combination of flexible fossil-fueled capacity with increased low-carbon emitting resources such as renewables and Canadian imports.

The technology offers the most operating flexibility of the technology options in the comparison.

Figure DEP-7 Performance Characteristics Comparison

Technology	Typical[1] Unit Size (MW)	Ramping[2] Ability to Full Load	Ramp Rate[3] (MW/Minute)	Turndown[4] Minimum Load (%)	Forced[5] Outage Rate	Unforced[6] Outage Rate	On-site[7] fuel?	Construction[8] Lead Times (Months)
Natural Gas Peaker from NRG Proposal								
GE 7HA.02 (Frame)	320	12 Minutes	27	40	8.16%	1.88%	Yes	15 - 20
Natural Gas Simple Cycle Peaker								
GE LMS100 PA 2x0	103.3	10 Minutes	10	50-75	3.00%	1.50%	possible	15 - 20
Natural Gas Combined Cycle								
Siemens SGT6-5000F (5) 2x2x1	720	45 Minutes	16	40-50	4.58%	1.83%	possible	30 - 36

Notes:

[1] Typical Unit Size is based on the technology specification sheets provided by GE and Siemens for each type of unit.

[2] Ramping ability is the ability to reach full load from start and for the natural gas peakers is based on the technology specification sheets provided by GE. The NERA cost of new entry study for NYISO provides the ramping ability for the Siemens SGT6-5000F.

[3] Ramp rate is calculated by dividing the typical unit size by the ramping ability to full load.

[4] Turndown minimum load for the natural gas peakers is based on the technology specification sheets provided by GE. The Siemens SGT6-5000F turndown rate is based on the NERA cost of new entry report for NYISO.

[5] The Forced Outage Rate for the GE 7HA.02 and Siemens SGT6-5000F units is based on data provided from the NERC GADS 2009-2013 Generating Unit Statistical Brochure (refer to "gas turbine" and "combined cycle" units). 'Forced Outage Rate' is the Equivalent Forced Outage Rate Demand (EFORd). The LMS100 forced outage rate is based on the rate reported in the Exelon Petition for approval of the Medway Project.

[6] The Unforced Outage Rate for the GE 7HA.02 and Siemens SGT6-5000F units is based on data provided from the NERC GADS 2009-2013 Generating Unit Statistical Brochure (refer to "gas turbine" and "combined cycle" units). 'Unforced Outage Rate' is the Maintenance Outage Factor (MOF). The LMS100 unforced outage rate is based on the rate reported in the Exelon Petition for approval of the Medway Project.

[7] On-site fuel storage is discussed in the NRG Petition for Canal 3. On-site fuel storage for the LMS100 and Siemens SGT6-5000F is possible, due to the units both being dual-fuel capable.

[8] Construction months for the natural gas simple cycle peaker and combined cycle are provided by S&L Technical Appendix of the Brattle Group Offer Review Trigger Prices study for ISO-NE. Canal 3 is assumed to follow a similar construction lead time as the natural gas simply cycle peaker. The range of the construction months also includes data reported in the Exelon Petition for approval of the Medway Project.

Figure DEP-8 Efficiency and Environmental Characteristics

Technology	HHV[1] Heat Rate (Btu/kWh)	Site Size[2] (acres)	CO_2 Emissions[3] (lbs/MWh)	Method[4] of Cooling	Other[5] Pollutants	Capability to Meet[6] Proposed EPA Requirements
Natural Gas Peaker from NRG Proposal						
GE 7HA.02 (Frame)	9,097	12	1,082	Air (Dry Cooling)	NOx, PM, CO, VOC	N/A
Natural Gas Simple Cycle Peaker						
GE LMS100 PA 2x0	9,073 - 9,244	10	1,079 - 1,099	Air (Dry Cooling)	NOx, PM, CO, VOC	N/A
Natural Gas Combined Cycle						
Siemens SGT6-5000F (5) 2x2x1	7,095 - 7,526	20	844 - 895	Air (Dry Cooling)	NOx, PM, CO, VOC	Yes (permit approval needed

Notes:

[1] Heat Rate is the engine specified LHV heat rate with a 10% adder. The technical specification sheet from GE was used to get the LHV heat rate for the GE 7HA.02 natural gas peaker. The heat rate for the natural gas peaker is a range created from the Brattle Group Offer Review Trigger Prices study for ISO-NE and the Exelon Petition for Approval of the Medway Project. The heat rate for the combined cycle is a range created from the Brattle Group Offer Review Trigger Prices study for ISO-NE and the NERA cost of new entry study for NYISO.

[2] Site size is taken from the NRG Petition. The Brattle Group Offer Review Trigger Prices study for ISO-NE Site is used to provide the site size for the natural gas peaker and combined cycle.

[3] CO2 emissions rates reflect operation on natural gas only and are calculated using the heat rate times 118.9 lbs of CO2 per MMBtu of natural gas.

[4] The majority of the cooling water systems installed in the past 15 years at electric generating facilities in Massachusetts have been dry (air) cooling systems. See the Brattle Group Offer Review Trigger Prices study for ISO-NE.

[5] List of other pollutants is generated from the NERA cost of new entry report for NYISO.

Figure DEP-9 Capital and O&M Cost Characteristics

Technology[1]	Overnight[2] Capital Cost (2015$/kW)	Fixed[3] O&M Costs (2015$/kw-year)	Variable[4] O&M Costs (2015$/MWh)
Natural Gas Peaker from NRG Proposal			
GE 7HA.02 (Frame)	$832 - $932	$4.8 - $9.3	$3.91 - $3.95
Natural Gas Simple Cycle Peaker			
GE LMS100 PA 2x0	$1,200	$17.02	$4.00
Natural Gas Combined Cycle			
Siemens SGT6-5000F (5) 2x2x1	$981 - $1,115	$13.9 - $27.4	$2.39 - $2.42

Notes:

[1] The natural gas peaker in the NRG proposal, which is based on the GE 7FA.02 combustion turbine from the Brattle Group CONE study for PJM, has its capital, fixed O&M, and variable O&M costs de-escalated from 2018 to 2015 dollars.

[2] Overnight capital cost for the natural gas peaker is taken from the Exelon Petition for Approval of the Medway Project and assumed to be in 2015 dollars. Overnight capital costs are taken from the Brattle Group CONE study for PJM for the combined cycle and are de-escalated to 2015 dollars.

[3] Fixed O&M costs for the natural gas peaker are taken from the Exelon Petition for Approval of the Medway Project and escalated to 2015 dollars from 2011. Fixed O&M costs are taken from the Brattle Group CONE study for PJM for the combined cycle and are de-escalated to 2015 dollars.

[4] Variable O&M costs for the natural gas peaker are taken from the Exelon Petition for Approval of the Medway Project and assumed to be in 2015 dollars. Variable O&M costs are taken from the Brattle Group CONE study for PJM for the combined cycle and are de-escalated to 2015 dollars.

Sources for Alternative Technology Figures

Sources for Alternative Technology Figures:

[1] NRG Petition

[2] Newell, Samuel, et al., "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM," The Brattle Group, May 15, 2014.

[3] Newell, Samuel, et al., "2013 Offer Review Trigger Prices Study" for ISO-NE, The Brattle Group, October 2013.

[4] Meehan, Eugene, et al., "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," Final Report, NERA Economic Consulting, August 2, 2013.

[5] Tierney, Susan, et al., "Petition of Exelon West Medway, LLC and Exelon West Medway II, LLC For Approval to Construct a Bulk Generating Facility in the Town of Medway," Testimony, Analysis Group, March 10, 2015.

[6] EIA, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015, " June 2015.

[7] NERC, GADS Data Reporting Instructions - Appendix F, January 2015, available at http://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/Appendix_F_Equations.pdf. 2009-2013 Generating Unit Statistical Brochure.

[8] NERC, GADS Generating Unit Statistical Brochure - All Units Reporting 2009-2013, August 5, 2014, available at http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx.

[9] GE Power Generation, "7HA.02 Gas Turbine," available at https://powergen.gepower.com/products/heavy-duty-gas-turbines/7ha-gas-turbine.html.

[10] GE Power Generation, "LMS100 Aeroderivative Gas Turbine," available at https://powergen.gepower.com/products/aeroderivative-gas-turbines/lms100-gas-turbine-family.html.

[11] Siemens Fossil Power Generation, "SGT6-5000F Combined Cycle," available at http://www.energy.siemens.com/hq/en/fossil-power-generation/gas-turbines/sgt6-5000f.htm#content=Description.

[12] CO2 emissions are from 40 CFR 75, Equation G-4 (Determination of CO2 Emissions), available at http://www.ecfr.gov/cgi-bin/text-idx?SID=2072a0cf3dbae2dd9749870a88c2279d&node=ap40.17.75_175.g&rgn=div9.

[13] EPA Proposed Rule, January 8, 2014, available at https://www.federalregister.gov/articles/2014/01/08/2013-28668/standards-of-performance-for-greenhouse-gas-emissions-from-new-stationary-sources-electric-utility.

V. Consistency with the Policies of the Commonwealth

Q. Please describe your understanding of the Siting Board's requirements to consider consistency with policies of the Commonwealth.

A. The Siting Board is required to make a determination that the Project is consistent with current health, environmental protection, and energy policies of the Commonwealth as required by Section 69J¼ of Chapter 164.

Q. Please describe the information you are offering with respect to this requirement.

A. I am offering information to explain how the proposed Project is consistent with the following policies:

1) The Electric Industry Restructuring Act of 1997 (EIRA),[47] specifically with respect to the competitive market for generation and the renewable portfolio standards.
2) The Global Warming Solutions Act of 2008 (GWSA),[48] specifically with respect to the accomplishment of greenhouse gas emission reductions in the electric sector of the economy.
3) The Green Communities Act (GCA),[49] specifically with respect to the provisions pertaining to the renewable portfolio standards and the Regional Greenhouse Gas Initiative (RGGI).

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[47] G.L. c. 164. The full title of the Act is "*An Act Relative to Restructuring the Electric Utility Industry in the Commonwealth, Regulating the Provision of Electric and Other Services, and Promoting Enhanced Consumer Protections Therein*."

[48] Chapter 269 of the Acts of 2008.

[49] Chapter 169 of the Acts of 2008.

Q. Please explain how the proposed Project supports these policies.

A. The proposed Project is consistent with and supports these policies, as follows:

1) Offers a competitive supply of capacity and peaking energy to the regional wholesale markets which will enhance the competitiveness of the markets and help assure that Massachusetts electric consumers have a reliable energy supply at competitive prices.
2) Offers dual-fuel capability to further assure reliability of electric supply and to mitigate the cost of electricity at times of high natural gas market prices due to congestion.
3) Facilitates the integration of renewable resources by adding fast-start and quick ramping ability to the regional power system.
4) Reduces emissions by displacing older, less-efficient units with higher emissions rates, such as oil-fired units and most existing gas-fired peaking units.

A. Electric Industry Restructuring Act of 1997

Q. Please explain the policies in the Electric Industry Restructuring Act that pertain to the proposed Project.

A. There are two aspects of the Act that pertain to the proposed Project.

First, the Act deregulated the generation of electric power in the Commonwealth. The proposed Project will be a provider of competitive wholesale power consistent with the authorities provided in the Act.

Second, the Act established a Renewable Portfolio Standard (RPS) for the Commonwealth. The proposed Project provides a new source of highly flexible, dispatchable capacity that will be needed in the system to complement increasing levels of non-dispatchable renewable resources that will be added under this policy.

Q. Please explain the implications of the competitive wholesale power market issue.

A. The Act established a competitive wholesale market as the preferred mechanism to provide sufficient supplies of electric generation to maintain the reliable service to the Commonwealth and allowing market forces to determine the suppliers of generation to provide lower cost supply.[50] I have described the current market mechanisms that ISO-NE has in place to accomplish this objective in Section III A of my testimony. The Project will meet an identified need for capacity as reflected in the FCM design. As a competitor in the upcoming FCA, the Project will help assure that the competitive markets produce the lowest cost outcome of that auction and reduce the costs that consumers in the Commonwealth will pay for capacity. The project will also offer a competitive energy supply for peaking energy.

Q. Please explain the implications of the RPS issue.

A. The Act established a renewable portfolio standard to require qualifying renewable energy resources be part of the supply mix for all competitive supplies offered in the Commonwealth.[51] The RPS policy was supplemented in the GCA. I discuss the synergies between the Project's dispatch flexibility and renewable energy portfolio development in the section on the GCA (see Section V C below).

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50 G.L. c. 164, § 1(i) and (k).

51 G.L. c. 25A, § 11F.

Q. Is the proposed Project consistent with the EIRA?

A. Yes. The Project is a competitive market solution being offered to address key needs for capacity, fuel diversity and peaking energy in the region's competitive marketplace. It also offers dispatch flexibility that will be needed in the regional power system as renewable energy resources are added to the system over time.

B. Global Warming Solutions Act

Q. Please explain the policies in the Global Warming Solutions Act that pertain to the proposed Project.

A. The GWSA, which was signed into law in August 2008, is a comprehensive regulatory program aimed at addressing climate change in Massachusetts. The goal of the program is to reduce GHG emissions between 10% and 25% below the 1990 GHG state emission levels by 2020 and 80% below the 1990 GHG state emission levels by 2050.[52]

The GWSA established the Commonwealth's policy for the reduction of greenhouse gas emissions, including the reduction of CO_2 emissions from electric generation facilities along with reduction of emission from other sectors of the economy. It also reinforced the Commonwealth's participation in the RGGI, a market-based program to constrain CO_2 emissions of electric generation on a regional basis.

The Project will emit CO_2 when it produces energy and will be a participant in the RGGI market for emissions allowances, even though the net impact of the Project will be to displace more CO_2 emissions than it produces. The Project's emissions will be part of the

[52] http://www.mass.gov/eea/air-water-climate-change/climate-change/massachusetts-global-warming-solutions-act/global-warming-solutions-act-background.html

generation emission cap established by the Secretary of Energy and Environmental Affairs in accordance with the GWSA.

Q. Please describe the impact of the proposed Canal 3 Project on CO_2 emissions.

A. The facility will have a direct and an indirect effect on CO_2 emissions.

The direct effect on emissions will be to displace the emissions from other, less efficient fossil-fired units that would otherwise operate to serve peaking energy requirements of the system.

The indirect effect pertains to the ability for the facility to provide the dispatch flexibility in the system that will be required to integrate increasing amounts of wind and solar energy into the regional power system.

Q. Please describe how the direct emissions impact would occur.

A. When operating on natural gas, the unit will be economically dispatched when the variable cost (including fuel, variable O&M, and RGGI allowance costs) is lower than alternative sources. Most of the peaking resources in the system today are either older, less efficient combustion turbines or older, fossil-fired steam turbines. Thus, in many hours of operation, the proposed facility will displace energy that would otherwise be produced by such units with higher emission rates.[53]

[53] The facility is expected to have a CO_2 emission rate of 1,082 pounds/MWh at full load when burning natural gas and a somewhat higher rate when operating on the oil back-up fuel.

When natural gas pricing or supply conditions cause a switch to oil, the emission rate for the facility will be higher, as would be the case for other resources that switch to oil in those periods. In some circumstances, the facility would displace natural gas-fired facilities (those that are not dual-fueled) that would continue to operate at the higher natural gas prices as needed in the market. Emissions displacement in this mode would differ somewhat from the displacement when operating on natural gas.

Q. Have you analyzed the unit's expected CO_2 emissions and the anticipated direct CO_2 emission reduction benefit to the New England Region?

Yes.

I prepared an estimate of the energy dispatch of Canal 3 from mid-2019 through 2029,[54] the first ten years of its operating life. A 10-year period was used to illustrate the impact, recognizing that an analysis of emissions beyond the year 2030 requires reliance on increasingly uncertain assumptions regarding the market.

I then compared the facility's projected monthly CO_2 emission rates that result from that simulation to the monthly ISO New England marginal emission rates for 2013.[55] The annual reduction in New England-wide CO_2 emissions from that analysis is depicted in Figure DEP-10.

In total, this analysis indicates CO_2 emissions reductions in the region of 143,618 tons over the 10-year study period,[56] representing approximately a 5 percent reduction in

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[54] Daymark Energy Advisors utilizes AURORAxmp® (AURORA) from EPIS to perform production cost modeling. AURORA is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets. See Attachment DEP-2 for a description of the assumptions used in this analysis.

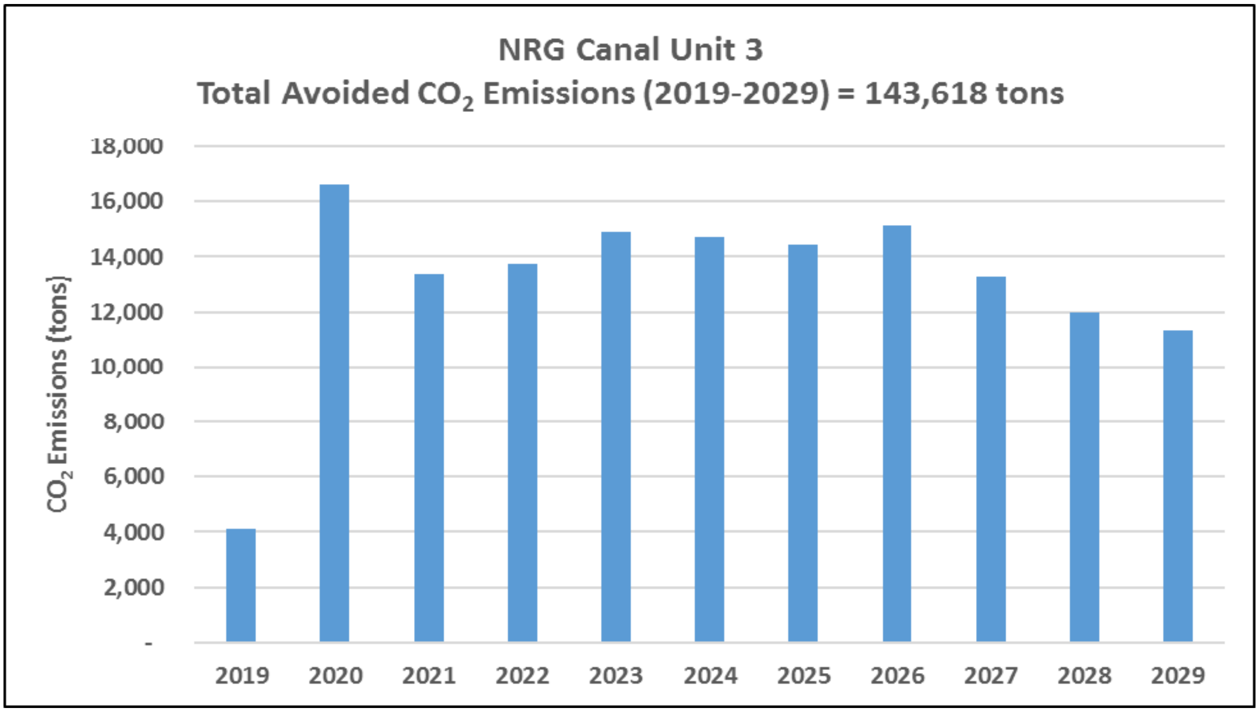
[55] 2013 ISO New England Electric Generator Air Emissions Report, Appendix Table 15, page 44.

[56] Consistent with the Canal 3 Unit in-service date being mid-2019, 2019 only contains a data for half of the year.

emissions. The annual capacity factor for the facility in this analysis ranged from 15 to nearly 20 percent. The analysis assumes the facility operates on natural gas.

The facility offers an improved emission performance over the facilities that have, in recent history, served as the marginal energy resources in the system.

Figure DEP-10 Total Avoided CO_2 Emissions



Q. **Please describe the indirect emissions impact.**

A. The indirect emissions impact relates to the role that the proposed Project will play in facilitating the expanded use of wind and solar PV in the electric system to reduce the emissions in the electric system.

The GWSA makes clear that renewable energy sources are an integral element of any plan to implement the GWSA greenhouse gas reduction targets.[57] Renewable resources are continuing to become more important to New England as clean power goals and policies are implemented to meet both current and future[58] environmental standards.

As renewable resources are added to the system the requirements for operating flexibility in the rest of the system increases. The addition of peaking facilities such as the proposed Canal 3 Project are important to the system as their quick start and ramp up capability can help support the integration of renewables.

ISO-NE has recognized, in its planning, that renewables will become a larger part of the region's fleet, stating that "*gas-fired generators, with their quick-start and ramp-up abilities, will prove vital in being able to pick up the slack when output drops from [wind and solar] units.*"[59] ISO-NE further states that "*when variable energy resources, particularly wind and PV, replace the capacity once provided by traditional generation, the need for flexible resources increases for providing operating reserves as well as other ancillary services, such as regulation and ramping. To date, increasing the 10-minute operating-reserve requirement and adding seasonal replacement reserves have improved the system-wide performance for meeting ramping needs in response to changing system conditions and contingencies. Natural-gas-fired combined-cycle units, fast-start units in*

57 G.L. c. 21N. Section 6.

58 The Clean Power Plan, designed to cut carbon emissions from power plants, was proposed by the EPA on June 2, 2014, and is currently under review in Massachusetts with a deadline of June 30, 2016 for the state to file an initial or complete implementation plan. http://www2.epa.gov/cleanpowerplan/fact-sheet-clean-power-plan-flexibility.

59 Regional Electricity Outlook, page 13.

service, and units listed in the ISO's Generation Interconnection Queue (the queue) will likely help meet the long-term evolving needs for operating reserves."[60]

The proposed Project offers the quick-start and ramping capabilities that ISO-NE has identified as being needed in the future as wind and solar resources are added to the system. The addition of units with these characteristics are needed to facilitate the integration of these resources into the power system.

Thus, the Project will provide indirect emissions reduction benefits by providing the necessary dispatch flexibility attributes needed in the system going forward to integrate low and no-carbon resources that do not have the dispatch flexibility to meet system reliability and operating requirements.

Q. Is ISO-NE's view of the need for quick-start gas units unique in the industry?

A. No. The notion that quick-start gas units will be important to the power system as the penetration of wind and solar resources increase is consistent with findings in other regions. For example, a recent study conducted for the California utilities examined the operational needs of its system for the 40 percent RPS policy (since increased to 50 percent) stressed the need for a thermal generation fleet with low minimum generation levels, high ramp rates, and flexibility on starts.[61] A recent Union of Concerned Scientist study of the potential for non-fossil resources to provide operating flexibility in

[60] *2015 Regional System Plan*. ISO-NE, November 5, 2015, pages 5-6.

[61] *Investigating a Higher Renewables Portfolio Standard in California*, Energy and Environmental Economics, Inc., January 2014, at 165.

California as part of the 50 percent renewable energy policy found that natural gas plants will play an important role in the implementation of that RPS policy.[62]

Q. Is the Project consistent with the Global Warming Solutions Act?

A. Yes.

The Project will add an efficient peaking resource to the system at emission rates below the marginal emissions rate in the system today and will provide an important source of operating flexibility to facilitate the expanded role of wind and solar energy sources needed to implement the objectives of the GWSA.

The choice of the quick-start, fast ramping technology for the Project is entirely consistent with the direction that the GWSA is setting for the power system going forward.

C. Green Communities Act

Q. Please explain the policies in the Green Communities Act that pertain to the proposed Project.

A. There are two aspects of the GCA that pertain to the proposed Project.

First, the GCA supplemented the RPS policy initial established in the EIRA. The proposed Project provides a new source of highly flexible, dispatchable capacity that will be needed in the system to complement increasing levels of non-dispatchable renewable resources that will be added under this policy.

62 *Achieving 50 Percent Renewable Electricity in California, The Role of Non-Fossil Flexibility in a Cleaner Electricity Grid.* Union of Concerned Scientists, August 2015, at 4.

Second, the GCA established statutory authorities for the Commonwealth's participation in RGGI. The Project will emit CO_2 when it produces energy and will be a participant in the RGGI market for emissions allowances, even though the net impact of the Project will be to displace more CO_2 emissions than it produces.

Q. Please explain the elements of the RPS policy that pertain to the Project.

A. The GCA set a renewable portfolio target to meet 20 percent of the Commonwealth's electric load with renewable energy by the year 2020. The GCA also includes provisions for long-term procurement of renewable resources.[63] These policies, coupled with the greenhouse gas emission reduction policies embodied in the GWSA, make clear that the Commonwealth's energy policy is to pursue increasing reliance on renewable energy sources.

In this context, it is the Commonwealth's policy to reach 20 percent reliance on renewable energy by 2020,[64] approximately the time that the Project will begin operation. I note that the GCA procurement authority is the basis for the current Clean Energy RFP that was recently issued jointly by Massachusetts, Connecticut and Rhode Island,[65] indicative of the broader, regional interest in an increase in the renewable energy supply.

The dispatch flexibility value that the Project offers will be important to the system in 2020 and the need for flexible resources will increase as further development of

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63 Section 83 of the GCA first established the obligations for competitive solicitation of long-term renewable contracts. In 2012, the GCA was amended with additional long-term procurement authorities established in Section 83A.

64 The goal includes a 15 percent target for Class I renewable energy sources and an additional 5 percent for other renewable and alternative energy sources included in the RPS.

65 The New England Clean Energy Request for Proposals (http://cleanenergyrfp.com/) was issued on November 12, 2015. Projects will be identified to advance clean energy goals in Connecticut, Massachusetts, and Rhode Island by purchasing clean energy and transmission through long-term contracts.

renewable energy occurs beyond 2020. The operating flexibility values I discussed above with respect to the GWSA are the same issues that are germane to the GCA RPS.

Q. Please explain the elements of the RGGI policy that pertain to the Project.

A. The GCA provided certain authorities for the Commonwealth's participation in a regional market for CO_2 emissions allowances. The RGGI cap-and-trade market began operating in 2009 and is currently targeting a cap of 88.7 million tons moving to a 78.2 million tons cap by 2020.[66] This market mechanism operated under authority established in the GCA. However, it is consistent with the GWSA policies to reduce greenhouse gases over time.

As I discussed with respect to the GWSA, the Project will emit CO_2 when it produces energy and will be a participant in the RGGI market for emissions allowances, even though the net impact of the Project will be to displace more CO_2 emissions than it produces.

Q. Is the Project consistent with the Green Communities Act?

A. Yes, and for virtually the same reasons that the Project is consistent with the GWSA.

The Project will add an efficient peaking resources to the system at emission rates below the marginal emissions rate in the system today and will provide an important source of operating flexibility to facilitate the expanded role of wind and solar energy sources needed to implement the objectives of the RPS policy. The choice of the quick-start, fast ramping technology for the Project is entirely consistent with the direction that the RPS policy is setting for the power system going forward.

66 http://www.rggi.org/design/overview/cap

The Project's lower CO_2 emissions rate, relative to the existing peaking supplies in the region will contribute to the overall reduction in emissions that are embodied in the RGGI market.

VI. Conclusions

Q. Please summarize your conclusions.

A. The Canal 3 Project will provide a reliable energy supply for the Commonwealth with minimal impact on the environment. Its efficiency and ancillary benefits to the operation of the electric system also promote a least cost solution to meeting the Commonwealth's electricity needs and are consistent with the policies established in the Electric Industry Restructuring Act, the Global Warming Solutions Act, and the Green Communities Act.

Specifically, I conclude that:

1) There is a need for new capacity in the region for resource adequacy reliability and to reduce the cost of capacity to consumers.

2) There is a need for dual-fueled capacity in the region to address reliability and cost of power supply issues deriving from the regions significant reliance on natural gas as the primary fuel for generation.

3) The proposed Canal 3 technology, the GE 7HA.02 combustion turbine, an alternative combustion turbine technology, the GE LMS 100, and a combined cycle technology, the Siemens SGT6-5000F, are the most reasonable alternative technologies to consider in assessing the merits of the proposed technology.

4) The proposed technology offers advantages over the LMS 100 and the Siemens CC on the basis of cost and operating flexibility. It is the lowest installed cost/kW, has the highest ramping rate and the lowest turn-down level.

5) The proposed Project is consistent with the Electric Industry Restructuring Act of 1997, being proposed as a competitive wholesale power supply entering the ISO-NE markets as contemplated by that Act.

6) The Project is consistent with the Global Warming Solutions Act, providing a new, more efficient peaking alternative to the market with emission rates lower than current market rates. Moreover, the high degree of operating flexibility that the Project will bring to the system is important to facilitate the integration of new renewable and low-carbon emitting sources that will be needed to meet the goals of that Act.

7) The Project is consistent with the Green Communities Act, providing the operating flexibility needed in the system as new renewable energy supplies are added to meet the RPS requirements. It will also provide a more efficient peaking resource that will help the region meet the carbon emission reduction targets in the RGGI cap-and-trade market.

Q. Does this conclude your testimony?

A. Yes.

DAYMARK ENERGY ADVISORS

ATTACHMENT DEP-1

Daniel E. Peaco

Chairman & Principal Consultant

SUMMARY

Daniel E. Peaco is Chairman of Daymark Energy Advisors (*formerly La Capra Associates*).

Mr. Peaco has 35 years of experience in the electric industry includes experience with a broad set of policy, planning, and decision support advice and analysis. Mr. Peaco has significant experience as an expert witness and as an advisor to senior utility managers and public policy officials. His consulting practice has included engagements relating to integrated resource planning, strategic planning, competitive electric markets, evaluation of generation asset investments, renewable energy policy, transmission planning, competitive procurement and power contracts, and industry restructuring.

Mr. Peaco joined the firm in 1996, served as its President from 2002-2015 and as Chairman since 2002. In addition to his tenure at the firm, he has held management and planning positions in power supply planning at Central Maine Power, CMP International Consultants, Pacific Gas & Electric, and the Massachusetts Energy Facilities Siting Council.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc. *(formerly La Capra Associates)*	*Boston, MA*
Chairman	Aug 2015-current
President	2002-July 2015
Managing Director	*1996-2002*
Central Maine Power Company	*Augusta, ME*
Manager, Industrial Marketing and Economic Development	1995-96
Principal, CMP International Consultants	*1993-95*
Director, Power Supply Planning	1987-93
Power Supply Planning Analyst	1986-87
Pacific Gas & Electric Company	*San Francisco, CA*
Power Supply Planning Analyst	1985-86
Hydropower Planning Analyst	1983-84
Cogeneration Contracts Analyst	1981-82
Massachusetts Energy Facilities Siting Council	Boston, MA
Planning Engineer	*1978-79*

EDUCATION

Thayer School of Engineering, Dartmouth College	*Hanover, NH*
M.S. in Engineering Sciences, Resource Systems and Policy Design	1981
Massachusetts Institute of Technology	*Cambridge, MA*
B.S. in Civil Engineering, Water Resource Systems	1977

PUBLICATIONS, PRESENTATIONS & CONFERENCES

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EXPERT TESTIMONY

Superior Court Windham Unit State of Vermont	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a the Bellows Falls hydropower facility (49 MW) in appeal of appraised values in the town of Rockingham VT.
Docket No. 547-11-12 Wmev		Valuation Report — April 23, 2015 Deposition — February 4, 2014 Oral Testimony — May 11, 12 and 13, 2015
Rhode Island Superior Court PC No. 2012-1847	TransCanada; Ocean States Power Holdings, Ltd.	Expert testimony regarding the valuation of a 540 MW combined cycle power plant in appeal of an appraisal conducted for the Town of Burrillville, RI. Prepared analysis of unit operations and revenue forecasts. Report for 12/31/2010 — December 19, 2012 Report for 12/31/2011 — July 17,2014 Deposition Testimony — May 2, 2015
Oklahoma Corporation Commission Cause No. PUD 201400229	OK Cogeneration	Testimony regarding Oklahoma Gas & Electric Company Application for pre-approval of its Mustang Modernization Plan, addressing planning for retirement of 430 MW of gas-fired steam generation and addition of 400 MW of Combustion turbine generation, cost pre-approval, and Requirements for competitive procurement and alternatives analysis. Pre-filed Testimony — December 16, 2014 Oral Testimony — March 18-19, 2015
Maine Public Utilities Commission Docket No. 2014-048	Central Maine Power	Testimony regarding CMP's application for approval Maine Power Connection Transmission Project. Testimony addressed economic benefits associated with Interregional transmission connection and associated wind energy development benefits. . Expert Report — September 5, 2014 Rebuttal Report — February 27, 2015 Oral Testimony — September 18, 2014 March 31, 2015
US District Court Colorado Civil Action No. 10-CV-02349-WJM-KMT	Nebraska Power Supply Issues Group	Expert testimony regarding Tri-State G&T cost to serve five Nebraska members. Expert Report — December 31, 2012 Deposition Testimony — February 27, 2013 Oral Testimony — May 19, 2014
Public Utilities Board Manitoba, Canada Needs For and Alternatives To (NFAT)	PUB NFAT Panel	Independent Expert (IE) for the review of Manitoba Hydro's Hydropower and Transmission Development Plan for 2,160 MW of hydro capacity at two locations, a 500 kV transmission line to Minnesota, and associated export contracts. Expert Reports I — January 24, 2014 Expert Reports II — February 28, 2014 Oral Testimony — April 8, 9, 10, 11, 2014

Superior Court State of Vermont Docket No. 423-9-12 Wmcv Docket No. 547-11-12 Wmev Docket No. 244-9-12 Cacv Docket No. 245-9-12 Cacv	TransCanada Hydro Northeast, Inc.	Expert testimony regarding the valuation of a four hydropower facilities totaling 260 MW in appeal of appraised values in the towns of Vernon, Rockingham, and Barnet VT. Valuation Report July 15, 2013 Deposition February 4, 2014
Arbitration AAA Case No. 11 198 Y 002014 12	City of Burlington, VT Burlington Electric Dept.	Expert testimony regarding the valuation of a 7 MW hydropower facility and the determination of fair value for transfer of ownership of the asset. Valuation Report June 21, 2013 Rebuttal Report July 26, 2013 Deposition Testimony September 12, 2013 Oral Testimony October 4, 2013
Arkansas Public Service Commission Docket No. 12-069-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's proposed divestiture of its transmission business to ITC Holdings. Direct Testimony April 19, 2013 Surrebuttal Testimony June 7, 2013 Supplemental Testimony - Rate MitigationAug 15, 2013
Arbitration AAA Case No. 11 153 Y 02133 11	Owners of Brassua Dam FPL Hydro Maine LLP Madison Paper Industries Merimil Ltd Partnership	Expert testimony regarding the valuation of a 4 MW hydropower facility and the determination of amortization reserve obligations under FERC license provisions. Valuation Report November 1, 2012 Amortization Reserve Report November 1, 2012 Amortization Reserve Rebuttal November 15, 2012 Oral Testimony December 5, 2012
Arkansas Public Service Commission Docket No. 10-011-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's strategic reorganization options and request for authorization to transfer control of its transmission asset to the Midwest ISO. Oral Testimony May 31, 2012 Surrebuttal Testimony April 27, 2012 Direct Testimony March 16, 2012
Burrillville Board of Review	TransCanada; Ocean States Power Holdings, Ltd.	Expert testimony regarding the valuation of a 540 MW combined cycle power plant in appeal of an appraisal conducted for the Town of Burrillville, RI. Valuation Report January 4, 2012 Oral Testimony March 1, 2012
Oklahoma Corporation Commission Cause No. PUD 201100186	OK Corporation Commission OK Attorney General	Testimony regarding a 60 MW Wind Energy Purchase Agreement and Cogeneration deferral Agreement proposed by Oklahoma Gas & Electric Company, addressing cost pre-approval, and a requested waiver from competitive procurement requirements. Pre-filed Testimony February 8, 2012

Arkansas Public Service Commission Docket No. 10-011-U	General Staff of the AK Public Service Comm.	Testimony regarding the evaluation of Entergy Arkansas's strategic reorganization options upon its exit from the Entergy System Agreement.	
		Oral Testimony	September 9, 2011
		Surrebuttal Testimony	August 18, 2011
		Supplemental Initial Testimony	July 12, 2011
		Initial Testimony	February 11, 2011
State Corporation Commission of the State of Kansas	The Landowner Group	Testimony regarding the application of ITC Great Plains for a siting permit for a 345-kV Transmission Line addressing project need and route selection methodology.	
		Initial Testimony	April 18, 2011
Federal Energy Regulatory Commission (FERC) RM10-23-000	Maine Public Utilities Commission, et. al.	Expert Affidavit regarding economic analysis methodology for transmission project evaluation. Provided in reply comments on the FERC Transmission Planning and Cost Allocation NOPR.	
		Affidavit	November 12, 2010
Maine Public Utilities Commission Docket No. 2008-255	Central Maine Power	Testimony regarding CMP's application for approval the Lewiston Loop 115kV Transmission Project. Testimony addressed non-transmission alternatives.	
		Oral Testimony	November 16, 2008 December 14, 2010
		Rebuttal Testimony	November 8, 2010 August 27, 2010
Oklahoma Corporation Commission Cause No. PUD 201000092	OK Corporation Commission OK Attorney General	Testimony regarding a 99.2 MW wind farm power purchase agreement and green energy choice tariff proposed by Public Service Company of Oklahoma, addressing cost pre-approval, resource need, and competitive procurement requirements.	
		Pre-filed Testimony	October 5, 2010
		Oral Testimony	November 3, 2010
Oklahoma Corporation Commission Cause No. PUD 201000037	Oklahoma Attorney General	Testimony regarding a 198 MW wind farm proposed by Oklahoma Gas & Electric, addressing cost pre-approval, resource need, and competitive procurement requirements.	
		Pre-filed Testimony	June 11, 2010
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 10-02-07	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2010 Comprehensive Plan for the Procurement of Energy Resources*.	
		Oral Testimony	June 2 & 3, 2010

Georgia Public Service Commission Docket No. 31081	Georgia Public Service Commission Public Interest Advocacy Staff	Witness sponsoring testimony regarding integrated resource planning methods, renewable energy, solar PV demonstration projects, and uncertainty analysis.	
		Written Testimony	May 7, 2010
		Oral Testimony	May 18, 2010
Maine Public Utilities Commission Docket No. 2008-255	Central Maine Power	Testimony regarding CMP's application for approval $1.5 B Maine Power Reliability Transmission Project. Testimony addressed non-transmission alternatives and economic benefits, economics of proposed solar alternative, wind energy development benefits.	.
		Oral Testimony	October 10, 2008 November 19, 2008 December 21, 2009 February 4, 2010
		Rebuttal Testimony	December 4, 2009 April 3, 2009
Oklahoma Corporation Commission Cause No. PUD 200900167	Oklahoma Attorney General	Testimony regarding a 102 MW wind farm proposed by Oklahoma Gas & Electric, addressing cost pre-approval, resource need, and competitive procurement. requirements.	
		Pre-filed Testimony	Sept 29, 2009
Oklahoma Corporation Commission Cause No. PUD 200900099	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding a power contract pre-approval and recovery of Independent Evaluator costs of Public Service Company of Oklahoma.	
		Pre-filed Testimony	July 14, 2009
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 09-05-02	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2009 Comprehensive Plan for the Procurement of Energy Resources*.	
		Oral Testimony	June 30, 2009
Connecticut Dept. of Public Utilities Control (DPUC) Docket No, 08-07-01	Connecticut Energy Advisory Board (CEAB)	Lead witness sponsoring the CEAB's *2008 Comprehensive Plan for the Procurement of Energy Resources*. This Plan is the first prepared under the State's new integrated resource planning statute.	
		Oral Testimony	August 28, 2008 September 22, 2008 October 3, 2008
Maine Superior Court Civil Action Docket No. cv-06-705	Worcester Energy Co., Inc.	Expert opinion regarding renewable energy and power procurement services.	
		Pre-filed Report	January 30, 2008
		Oral Testimony	March 18, 2009

Massachusetts Dept. Of Telecommunications And Energy Docket No. DTE/DPU-06-60	Russell Biomass	Testimony regarding economic, reliability and environmental need for renewable power in the Massachusetts and New England in support of Russell Biomass petition for a zoning exemption. Pre-filed Testimony — June 2007 Oral Testimony — October 30, 2007
Hawaii Public Utilities Commission Docket No. 04-0046	Hawaii Division of Consumer Advocacy	Testimony regarding Hawaii Electric Light Company's integrated resource plan. Pre-filed Testimony — September 28, 2007 Oral Testimony — November 26, 2007
Nevada Public Utilities Commission Docket No. 06-12002	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the prudency of Sierra Pacific Power Company in its purchased power expenses for the period December 2001 through November 2002. Pre-filed Testimony — September 14, 2007
Oklahoma Corporation Commission Cause No. PUD 2005516 Cause No. PUD 2006030 Cause No. PUD 2007012	Oklahoma Attorney General	Testimony regarding a 950 MW coal-fired generation facility proposed by Public Service of Oklahoma and Oklahoma Gas & Electric, including IRP, competitive procurement, and construction financing issues. Pre-filed Testimony — May 21, 2007 Rebuttal Testimony — June 18, 2007 Oral Testimony — July 26, 2007
Oklahoma Corporation Commission Cause No. PUD 2002-038 REMAND	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding a power contract proposal of Lawton Cogeneration and the pricing analysis of Public Service Company of Oklahoma. Pre-filed Testimony — October 28, 2005 Rebuttal Testimony — March 17, 2006 Oral Testimony — May 9, 2006
New Brunswick Board of Commissioners of Public Utilities (PUB) Ref: 2005-002	New Brunswick Power Distribution Company	Testimony regarding La Capra Associates' three technical audits of the NBP-Disco purchased power budget and variance analyses for FY 2004 – 2006. Oral Testimony — February 14-22, 2006
Connecticut Department of Public Utility Control Docket No. 05-07-14 Phases I and II	Connecticut Energy Advisory Board	Testimony regarding Connecticut's need for electric capacity to meet reliability requirements and to mitigate congestion charges in the wholesale markets. Oral Testimony — February 14-22, 2006 May 1, 2006 June 15, 2006 September 26, 2005

Hawaii Public Utilities Commission Docket No. 03-0372	Hawaii Division of Consumer Advocacy	Testimony regarding competitive bidding rules and integrated resource planning.	
		Oral Testimony	December 12-16, 2005
Oklahoma Corporation Commission Cause No. PUD 2005-151	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding resource planning, prudency of generation investment of Oklahoma Gas & Electric Company.	
		Pre-filed Testimony	September 12, 2005
		Rebuttal Testimony	September 29, 2005
		Oral Testimony	October 18, 2005
Oklahoma Corporation Commission Cause No. PUD 2003-076	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding resource planning, prudency of generation investment and fuel and purchased power expenses of Public Service Company of Oklahoma.	
		Pre-filed Testimony	January 4, 2005
Oklahoma Corporation Commission Cause No. PUD 2003-633/4	Oklahoma Industrial Energy Consumers (OIEC)	Testimony regarding power contract proposal for Blue Canyon wind development and avoided costs of Public Service Company of Oklahoma.	
		Pre-filed Testimony	August 16, 2004
Civil Litigation Maine Superior Court Docket No. CV-01-24	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Benton Falls Associates.	
		Deposition Testimony	April 28, 2004
Oklahoma Corporation Commission	Oklahoma Attorney General	Testimony regarding power contract proposal for PowerSmith Cogeneration and avoided cost analysis of Oklahoma Gas & Electric Company.	
		Pre-filed Testimony	February 18, 2004
		Rebuttal Testimony	March 16, 2004
		Oral Testimony	August 4, 2004
Nevada Public Utilities Commission	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the Nevada Power Company's Integrated Resource Plan and associated financial plan.	
		Pre-filed Testimony	September 19, 2003
		Oral Testimony	October 15,2003
Massachusetts Energy Facilities Siting Council Docket No. EFSB-02-2	Cape Wind	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new wind power facility.	
		Pre-filed Testimony	February 14, 2003
		Oral Testimony	August 6&7, 2003
Maine State Board of Property Tax Review	United American Hydro	Testimony regarding the Maine and New England power market prices pertaining to the valuation of a hydro-electric power facility in Winslow, Maine.	
		Oral Testimony	June18, 2003

Nevada Public Utilities Commission Docket No. 03-1014	Nevada Attorney General Bureau of Consumer Protection	Testimony regarding the prudency of Sierra Pacific Power Company in its purchased power expenses for the period December 2001 through November 2002.	
		Pre-filed Testimony	April 25, 2003
Oklahoma Corporation Commission Cause No. PUD 2002-038	Oklahoma Attorney General	Testimony regarding a power contract proposal of Lawton Cogeneration and the pricing analysis of Public Service Company of Oklahoma.	
		Pre-filed Testimony	December 16, 2002
		Oral Testimony	May 22, 2003
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas.	
		Pre-filed Testimony	September 4, 2001
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the Development of Competition in Electric Markets and the Impact on Retail Consumers in Arkansas.	
		Pre-filed Testimony	September 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the establishment of uniform Policies and guidelines for a Standard Service Package.	
		Staff Proposal and Comments	June 13, 2000
		Reply Comments	July 21, 2000
		Sur reply Comments	August 2, 2000
		Oral Testimony	August 8, 2000
		Petition for Rehearing	
		Rebuttal Testimony	November 15, 2000
		Oral Testimony	November 29, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the determination of the merits of declaring retail billing services competitive effective At the start of retail open access.	
		Oral Testimony	June 27, 2000
		Pre-filed Rebuttal Testimony	June 23, 2000
		Pre-filed Testimony	June 16, 2000
		Oral Testimony	May 10, 2000
Arkansas Public Service Commission	General Staff of the AK Public Service Comm.	Testimony regarding the minimum filing requirements for market power studies to be filed by the Arkansas Electric utilities and affiliated retail companies.	
		Oral Testimony	June 1, 2000
Amer. Arb. Assoc. No. 50T 198 00197-98	Vermont Joint Owners	Testimony regarding economic damages resulting from alleged breach of a long-term purchase power agreement between Hydro-Quebec and Vermont utilities (VJO).	
		Oral Testimony	May 25, 2000
		Pre-filed Rebuttal Testimony	February 10, 2000
		Pre-filed Testimony	August 13, 1999

Rhode Island Energy Facilities Siting Board	Indeck-North Smithfield, L.L.C.	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility. Pre-filed Testimony August 16, 1999 Oral Testimony August 17, 2000 Pre-filed Testimony January 26, 2001 Oral Testimony March 23, 2001
Civil Litigation Maine Superior Court Docket No. CV-98-212	Central Maine Power Co.	Factual and expert witness in litigation regarding pricing provisions of a purchased power agreement between Central Maine Power and Regional Waste Systems. Deposition Testimony May 5, 1999
Connecticut Energy Facilities Siting Council Docket No. 190	PDC – El Paso Meriden LLC	Testimony regarding economic, reliability and environmental need for power in the Connecticut and New England power markets regarding the need for new, merchant power facility. Pre-filed Testimony January 25, 1999
Rhode Island Energy Facilities Siting Council Docket No. SB-98-1	R. I. Hope Energy, L. P.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony November 4, 1998 Pre-filed Testimony October 30, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-91-101A	Cabot Power Corp.	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony May 27, 1998 Pre-filed Testimony August 15, 1997
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-2	ANP Blackstone Energy	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony April 6, 1998 Pre-filed Testimony January 23, 1998
Massachusetts Energy Facilities Siting Council Docket No. EFSB-97-1	ANP Bellingham	Testimony regarding economic, reliability and environmental need for power in the Massachusetts and New England power markets regarding the need for new, merchant power facility. Oral Testimony February 3, 1998 January 28, 1998
Rhode Island Energy Facilities Siting Board Docket No. SB-97-1	Tiverton Power Associates LP	Testimony regarding economic, reliability and environmental need for power in the Rhode Island and New England power markets regarding the need for new, merchant power facility. Oral Testimony October 15, 1997 Pre-filed Testimony October 1, 1997

Maine Public Utilities Commission Docket No. 92-102	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the prudency of power purchase contract decisions with regard to contract awards and contract management. Oral Testimony — July 1993 Deposition Testimony — February 25, 1993; March 1, 1993 Pre-filed Rebuttal Testimony — June 7, 1993 Pre-filed Testimony — June 15, 1992
Maine Public Utilities Commission Docket No. 92-315	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the relationship of marginal costs of generation to embedded costs. Supplemental Pre-filed Testimony — April 20, 1993 Pre-filed Testimony — February 17, 1993
Maine Public Utilities Commission Docket No. 87-261 Docket No. 88-111	Central Maine Power	Testimony regarding CMP's avoided cost methods and practices pertaining to the setting of long-term avoided costs, CMP's Energy Resource Plan, and the proposal for a 900 MW power Contract with Hydro Quebec. Oral Testimony — Summer 1988 Pre-filed Testimony — October 31, 1987

REGIONAL MARKET MODELING ASSUMPTIONS

NOVEMBER 30, 2015

PREPARED FOR

NRG Canal 3 Development LLC

PREPARED BY

Daymark Energy Advisors

TABLE OF CONTENTS

I. INTRODUCTION

This report contains a description of assumptions used in a New England electric market modeling analysis in support of the Direct Testimony of Daniel Peaco offered in support of the Petition to Construct the Canal 3 Project before the Energy Facilities Siting Board (EFSB). This report is incorporated into Mr. Peaco's testimony.

NRG Canal 3 Development LLC (Canal 3) and NRG Canal LLC (NRG Canal) propose to construct a state-of-the-art, dual-fueled simple cycle electric generating facility known as the Canal Unit 3 Project (Canal 3 or Project) with an in-service date of June 2019. The proposed Project requires EFSB approval under G.L. c. 164, §69J¼.

NRG Canal retained Daymark Energy Advisors[1] (Daymark) to provide an evaluation of the proposed Project with respect to two issues that will be considered by the EFSB. The proposed project does not met all applicable Technology Performance Standards[2] and, therefore, is required to provide a comparison of the selected technology to alternative fossil-fueled technologies. The petitioner also must show that the proposed Facility is consistent with current health and environmental policies of the Commonwealth.

Daymark performed a production cost modeling analysis to develop analysis presented in Mr. Peaco's testimony. The model results were used to derive the ISO-NE energy mix for the 2019 – 2029 period depicted in Figure DEP-6 and to forecast the energy output of Canal 3 over the first ten years of is proposed operation as input to the forecast of reductions in regional carbon emissions from the addition of the unit presented in Section V.B. of that testimony.

The production cost modelling analysis is a reference case or baseline scenario consistent with assumptions included in other regional economic analyses, relying on input that have been developed through regional consensus where available. This includes relying on assumptions developed for ISO-NE economic studies developed through its regional stakeholder process.

This appendix describes the energy market analytical methodology and provides details on key assumptions.

[1] Daymark Energy Advisors is the new name of the firm formerly known as La Capra Associates. The name change occurred on November 9, 2015.

[2] 980 CMR 12.02(2).

II. NORTHEAST MARKET MODEL STRUCTURE

The Daymark Energy Advisors' Northeast Market Model (NMM) was used to perform simulation of market operations and operation of the Canal 3 unit over the period 2019 - 2029. This Section provides a description of the NMM structure.

A. Northeast Market Model Overview

The NMM uses an hourly chronologic electric energy market simulation model on the AURORAxmp® software platform (AURORA).[3] The NMM is a zonal representation of the electrical system of New England, New York and the neighboring regions

The underlying technology, AURORA, is a well-established, industry-standard simulation model that uses and captures the effects of multi-area, transmission-constrained dispatch logic to simulate real market conditions. AURORA captures the dynamics and economics of electricity markets.

AURORA realistically approximates the formation of hourly energy market clearing prices on a zonal basis using all key market drivers, including fuel and emissions prices, loads, demand-side management ("DSM"), generation unit operating characteristics, unit additions and retirements, and transmission congestion and losses.

The NMM utilizes a comprehensive database representing the entire Eastern Interconnect (the North American interconnected power system east of the Rockies), including representations of power generation units, zonal electrical demand and transmission configurations. Daymark constructed this database from a number of established sources of information, including:

1. A comprehensive database issued by EPIS, Inc., the developer of AURORA;
2. The U.S. Department of Energy's Energy Information Administration ("EIA");
3. The Independent System Operator of New England ("ISO-NE");
4. The New York Independent System Operator ("NYISO"); and
5. The New York Mercantile Exchange ("NYMEX").

Daymark supplements the EPIS database with custom updates and revisions of key inputs for the New England and New York markets, as well as more limited updates to neighboring control areas.

[3] AURORA is one of the leading commercially-available market simulation software and North American database package offered by EPIS, Inc. (http://epis.com/). Daymark has licensed the AURORA system for market simulation applications since 2008.

B. Northeast Market Model Topology

The NMM is a zonal model, where each defined zone represents a “bubble” of load and generation with each zone defined by the key transmission interfaces within the system. The transmission system is represented as single, composite links between zones with constraints on certain combinations of links to represent the transmission interface characteristics. The zones for the New England system are defined to be consistent with ISO-NE’s zonal definitions in the Regional System Plan.[4]

Key attributes that can be defined for each individual link are wheeling costs, transfer losses and transfer capability. The constraints on sets of links internal to ISO-NE are shown in Table 1.

The topology of ISO-NE and contiguous areas used to model the MREI is shown in **Figure 1** below along with a summary of interfaces.

The Canal 3 project is included in the SEMA zone.

C. Reference Case

Daymark developed a Reference Case analysis based on a set of assumptions designed to provide a reasonable forecast of New England market conditions.

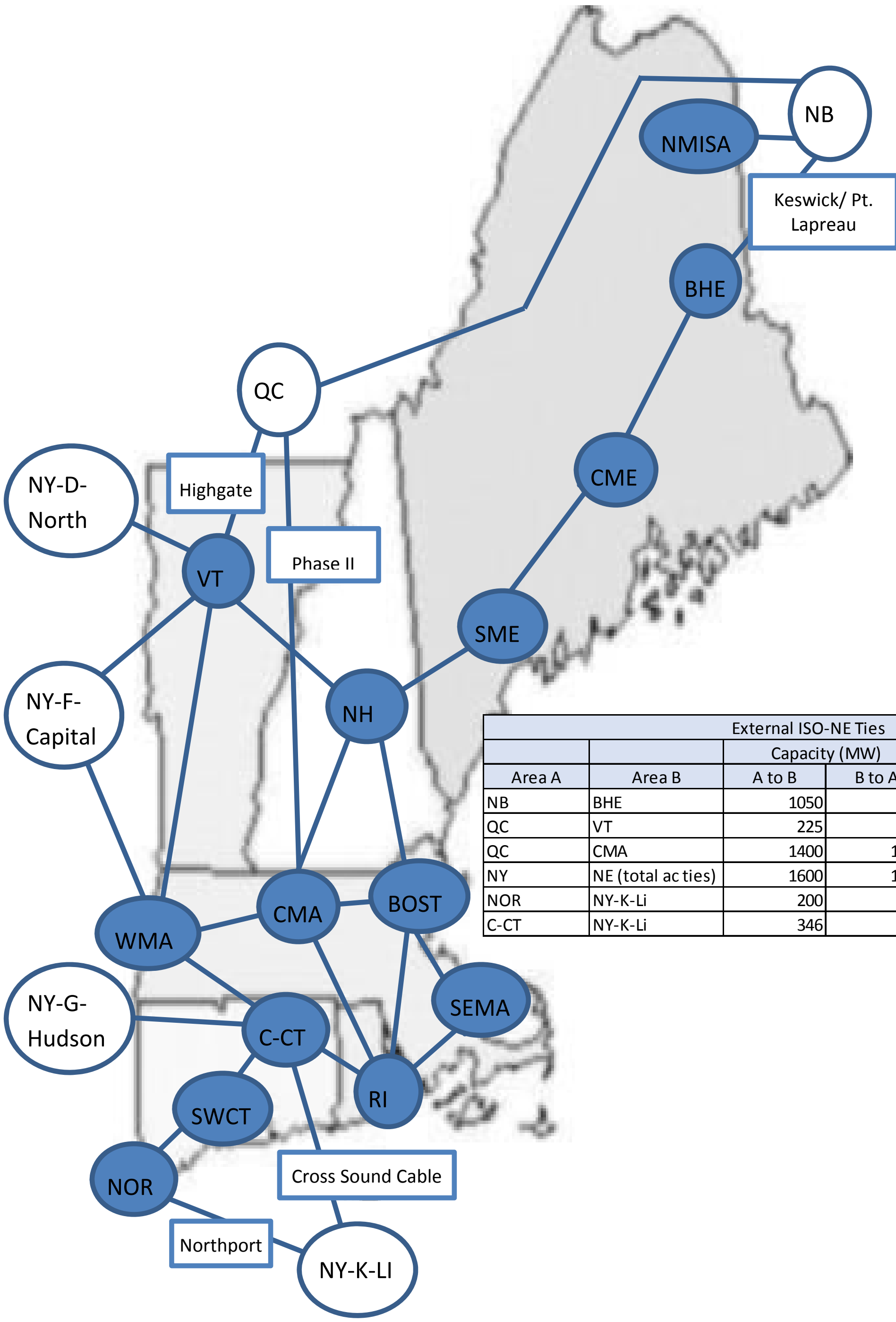
The key assumptions of this analysis include:

- Fuel prices: The Reference Case analysis uses our reference fuel price forecasts. Most important of these is the New England natural gas price. The reference fuel prices are defined in detail in Section III.
- Resource retirements: Our Reference Case assumes a status quo retirement scenario in which no New England generators retire throughout the study period, other than those units that have already delisted from the FCM or have announced definite retirement plans. These units are identified below.
- Renewables: We similarly assume a status quo for our Reference Case renewable buildout. We assume that any project currently operating, under construction, or announced (with a contract in place for the project output) will be built. In addition, we assume that additional renewable energy resources are developed to assure that the region meets established Renewable Portfolio Standards (RPS).

[4] *2015 Regional System Plan*, ISO-NE, November 5, 2015. Figure 2-3 at 31.

	Transfer Limits (MW)	
	Main	Reverse
North-South Interface		
Sum of Links (VT to WMA; NH to CMA; NH to Boston)	3,600	3,600
Interface Limit	2,675	2,675
East-West Interface		
Sum of Links (VT to NH; WMA to CMA; CT to RI)	3,600	3,600
Interface Limit (2018 and after)[2]	3,500	2,200
Boston Import Interface		
Sum of Links (NH to BOS; CMA to BOS; RI to BOS; SEMA to BOS)	6,000	6,000
Interface Limit	4,900	4,850
SEMA-RI Export Interface		
Sum of Links (RI to C-CT, CMA and BOST; SEMA to BOST)	4,800	4,800
Interface Limit (2018 and after)[2]	3,400	1,280
Connecticut[1] Interface		
Sum of Links (RI to CT; WMA to CT; NY-G to CT; NY-K to NOR)	3,430	3,388
Interface Limit (2018 and after)[2]	2,950	2,950
SWCT Import Interface		
Sum of Links (C-CT to SWCT; NY-K to NOR)	2,830	2,788
Interface Limit	3,200	3,200
[1] CT Interface does not include Cross Sound Cable (NY-K to C-CT)		
[2] NEEWS Interstate Reliability Program assumed in-service by 2018		

Table 1. NMM Model Directional Transfer Limit Assumptions



External ISO-NE Ties					
		Capacity (MW)		Hurdle Rate (2012$/MWh)	
Area A	Area B	A to B	B to A	A to B	B to A
NB	BHE	1050	550	$ 10.00	$ 10.00
QC	VT	225	200	$ 10.00	$ 10.00
QC	CMA	1400	1400	$ 10.00	$ 10.00
NY	NE (total ac ties)	1600	1575	$ 1.32	$ 1.32
NOR	NY-K-Li	200	200	$ 1.32	$ 1.32
C-CT	NY-K-Li	346	330	$ 1.32	$ 1.32

Figure 1. NMM Model Topology: ISO-NE and regional interconnections

III. KEY ASSUMPTIONS AND INPUTS

This section provides details on the key inputs and assumptions used in the NMM energy market analysis.

A. Canal 3 Modeling

The key modeling parameters for the proposed Canal 3 plant which were included in the NMM analysis are presented in Table 2 below.

Input	Units	Canal 3	Notes & Additional Options
Full Load Heat Rate	Btu/kWh	9097	
Winter Capacity	MW	337	7% Derate in Summer
Fuel		Natural gas	
Variable O&M	$/MWh	3.67	2012 $, subject to inflation
Forced Outage	Percent	8.16	Modeled as a decrease to capacity
Maintenance Rate	Percent	1.88	Modeled as a decrease to capacity
Minimum Capacity	Percent	40	As percent of full load Capacity above
Resource Begin Date	date	6/1/2019	
Hourly Ramp Rate	percent	0	Unit allowed to dispatch to full load in one hour
NOx Emissions Rate	lb/MMBtu	119	Generic emissions rate for new NG CT
CO_2 Emissions Rate	lb/MMBtu	0.15	Generic emissions rate for new NG CT
SO_2 Emissions Rate	lb/MMBtu	0.0012	Generic emissions rate for new NG CT

Table 2. Canal 3 Assumptions

B. Load

The load forecast for New England is based on the 2015 CELT report.[5] The load forecast values in the CELT report are reported by zone (Figure 1) and are represented in the NMM for each zone.

For the 2019-2024 period, the 2015 CELT report provided gross peak and energy load and peak and energy load net of energy efficiency (EE).[6] ISO-NE's EE forecast in the CELT report includes estimates based both on the resources cleared in the New England Forward Capacity Market (FCM) and the load reduction projected due to state-sponsored EE programs. For the period 2025-2029 (the end of the study period), gross load is assumed to grow at the compound annual growth rate from 2019-2024. EE reductions are extrapolated such that EE's percent of gross load, both peak and energy, in 2024 remains constant through the rest of the study period. These extrapolations are done separately for each zone in the system.

Figure below shows the gross and net coincident peak load for the New England system as a whole. Figure shows the gross and net energy demand for New England.

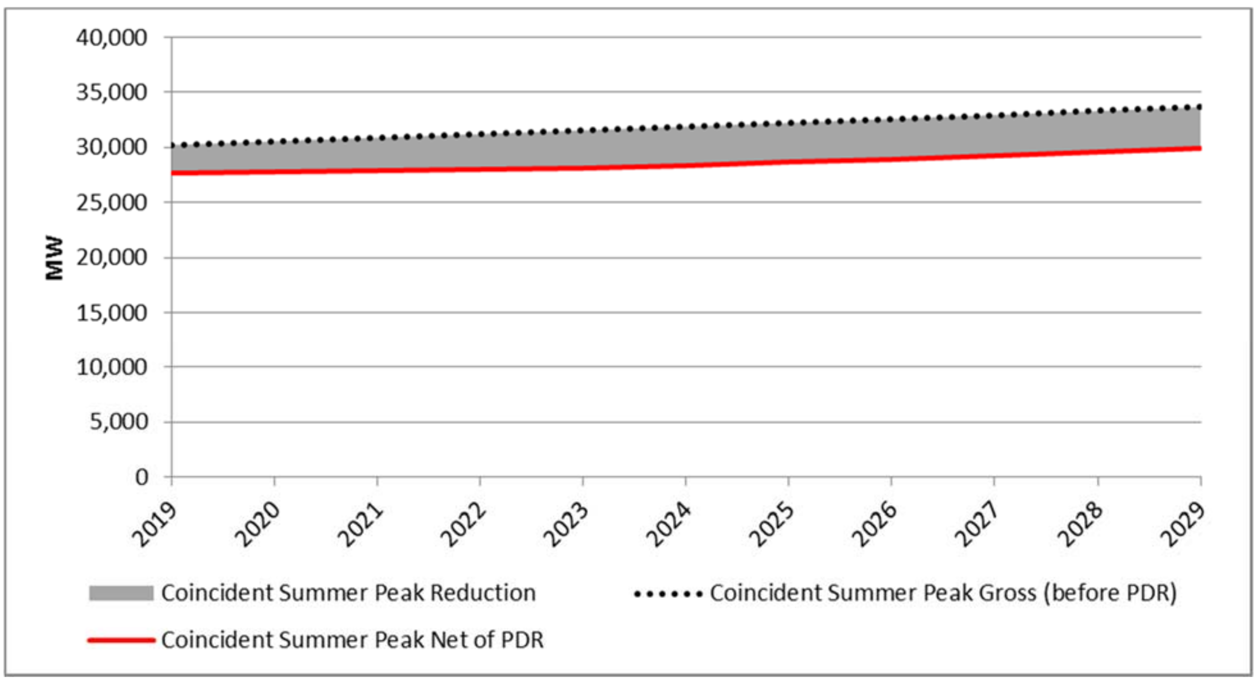


Figure 2. New England coincident peak load – gross and net of EE

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[5] *CELT Report: 2015-2024 Forecast Report of Capacity, Energy, Loads, and Transmission*, ISO-NE, May 1, 2015.

[6] ISO-NE refers to EE as "passive demand resources" (PDR).

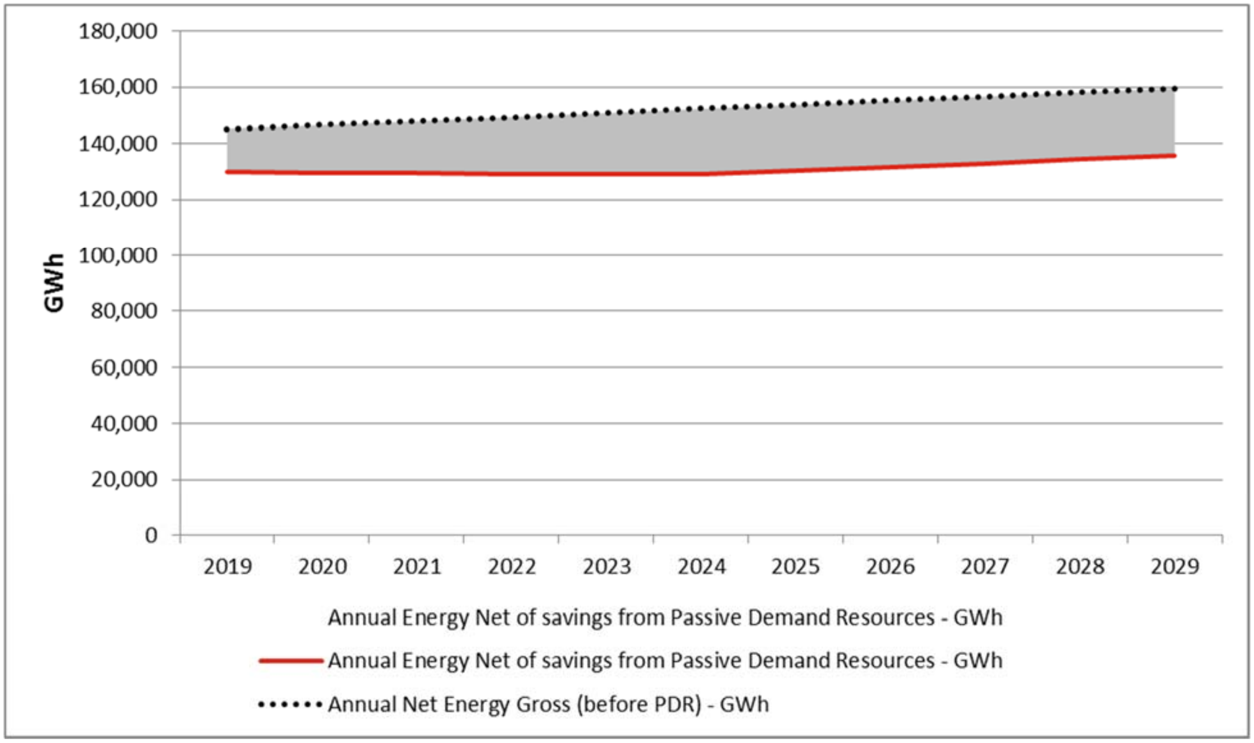

Figure 3. New England energy load – gross and net of EE

Dispatchable Demand Resources (DR) units are added to New England in AURORA based upon the level of DR that has cleared in auctions in ISO-NE's Forward Capacity Market (FCM). In the seventh annual Forward Capacity Auction (FCA), FCA #7, the level of DR clearing the market dropped significantly from the level that had been clearing previously, and in FCA #9, the level of DR dropped again from just over 1,000 MW in FCA #8 to 647 MW. DR capacity (in MW) for years beyond FCA #9 is assumed to remain constant at the level of the last FCA. **Error! Reference source not found.** summarizes the level of DR by state in New England based on the FCA results. These units are modeled as "load control" units in the NMM, and therefore when dispatched they act to reduce load instead of providing generation.

	2019-2029
CT	128
MA	229
ME	155
NH	30
RI	68
VT	37
NE Total	647

Table 3. New England total DR Capacity (MW)

C. Fuel prices

The following sections describe our assumptions regarding natural gas and oil prices.

Natural Gas Prices

The ISO-NE market is currently dominated by natural gas generation and will likely remain so for the foreseeable future. Therefore, the natural gas price assumptions are a critical driver to our modeling and results.

The price of natural gas for New England generators in Aurora is constructed according to the following basic formula for year *y,* month *m*:

$$\mathbf{DP}_{y,m} = (\mathbf{HHA}_{y} * \mathbf{HHM}_{y,m}) + (\mathbf{ACGA}_{y} * \mathbf{ACGM}_{m}) + \mathbf{R}_{m} + \mathbf{p}$$

Where:

DP	=	Delivered price to New England generator
HHA	=	Henry Hub annual average price
HHM	=	Henry Hub monthly shape factor
ACGA	=	Algonquin City-gates basis differential annual average
ACGM	=	Algonquin City-gates basis differential monthly shape factor
R	=	Regional adder, if any (for northern New England)
p	=	Peaking unit adder

The derivation of each of the terms in the equation above is explained in the sections below.

Henry Hub Annual

The reference forecast is based on the U.S. Energy Information Administration's (EIA) Short-Term Energy Outlook (STEO)[7] and Annual Energy Outlook.[8] The STEO forecast provides Henry Hub prices through the end of 2016. Subsequent annual prices are derived by escalating the 2016 STEO price at the compound annual growth rate of EIA's Annual Energy Outlook (AEO) Reference Case Henry Hub price. **Figure** below displays the Henry Hub forecast.

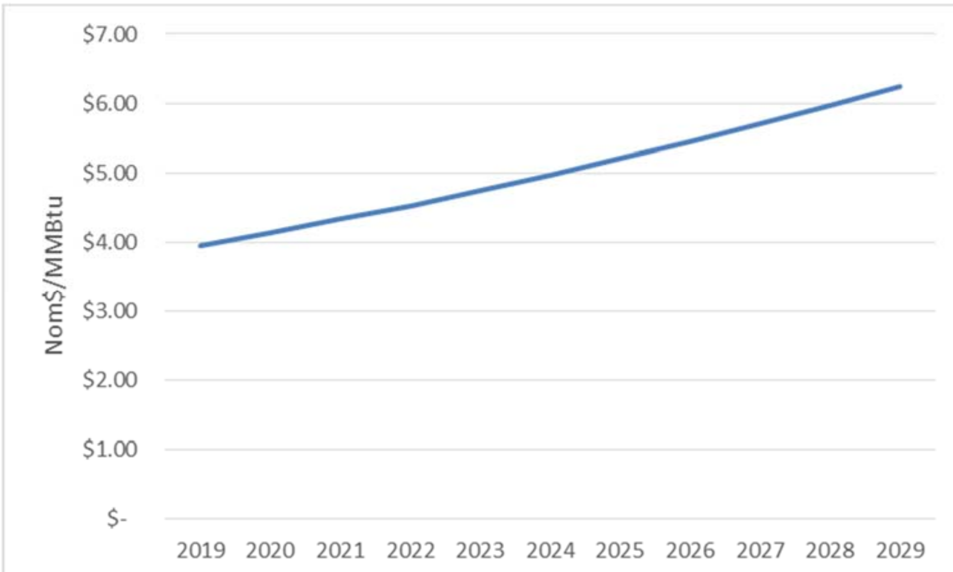

Figure 4. Henry Hub Price Forecast

Henry Hub Monthly Shape

The monthly shape vector for Henry Hub prices is based on the value used by EPIS in its default AURORA database. These values are multiplied by the annual Henry Hub prices to yield monthly values. **Figure 2** below displays the monthly Henry Hub shape.

[7] Short-Term Energy Outlook, U.S. Energy Information Administration is issued monthly. http://www.eia.gov/forecasts/steo/

[8] Annual Energy Outlook 2015, U.S. Energy Information Administration, April 14, 2015. http://www.eia.gov/forecasts/aeo/

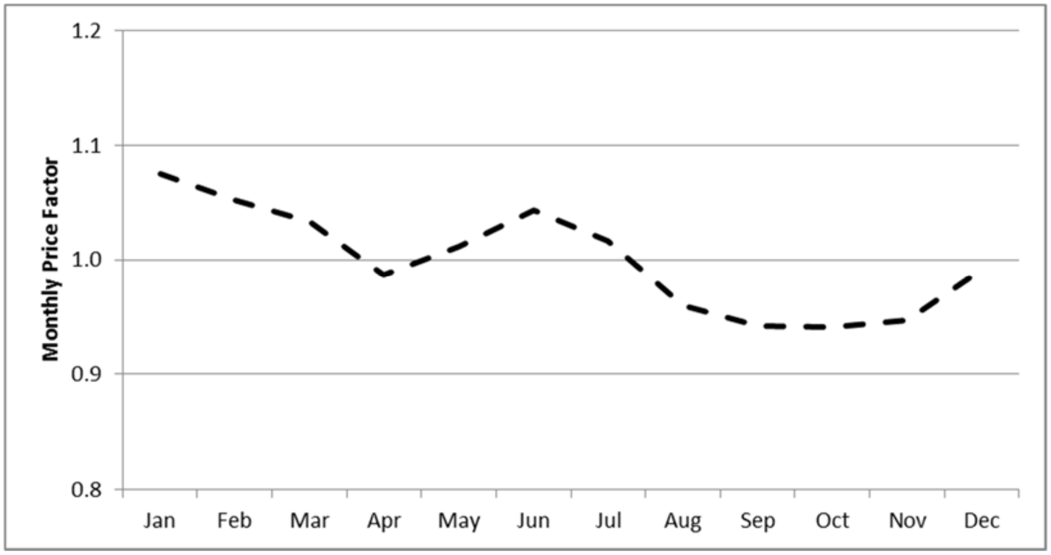

Figure 2. Monthly Henry Hub Shape

New England Basis Differential

We assume that the basis differential paid by natural gas generators in New England is tied to the Algonquin Citygate[9] basis.

The basis differential has recently been a critical component of energy prices in New England, particularly in the winter. After remaining fairly stable at an annual average of around $1/MMBtu for most of the last decade, price spikes in the last two winters brought the 2013 and 2014 annual average basis to more than $3/MMBtu. There has been significant effort in New England over the past two years to address natural gas pipeline constraints with the goal of reducing the Algonquin Citygate basis. These efforts have occurred on both state and regional levels and have included several proposals for additional pipeline capacity.

In our Reference Case, we assume that the recent extreme basis differentials will be mitigated by pipeline expansions underway and being planned, by ISO New England ("ISO-NE") market changes and system operations changes, by regional policy initiatives to support pipeline expansion in the region, and by market responses from alternative fuel suppliers, demand response providers, and imports of power from Canada and New York.

In addition to the expected resolution of the winter basis peaks, the national natural gas markets have shifted over the past few years due to the shale gas developments. Whereas the Henry Hub index has historically represented the commodity price hub for fuel prices elsewhere, recent market prices have demonstrated a shift. Pricing hubs closer to the Marcellus shale gas regions have recently exhibited the lowest prices, and during shoulder seasons, delivered New England

[9] Algonquin Citygate is a pricing hub based on transactions to delivery points within the Algonquin system in New England.

prices and Henry Hub prices have been trading comparably, and both have traded above the commodity shale gas price at pricing hubs at Marcellus.

For our Reference Case, we assume that the basis differential from Algonquin to the commodity price reverts to historical levels of approximately $1/MMBtu. We also assume that the commodity price hub shifts to the Marcellus shale. As a result, on an annual basis Algonquin Citygate prices become equivalent to Henry Hub prices. This zero annual basis value is shaped by month, resulting in the monthly basis in **Figure 3** below.

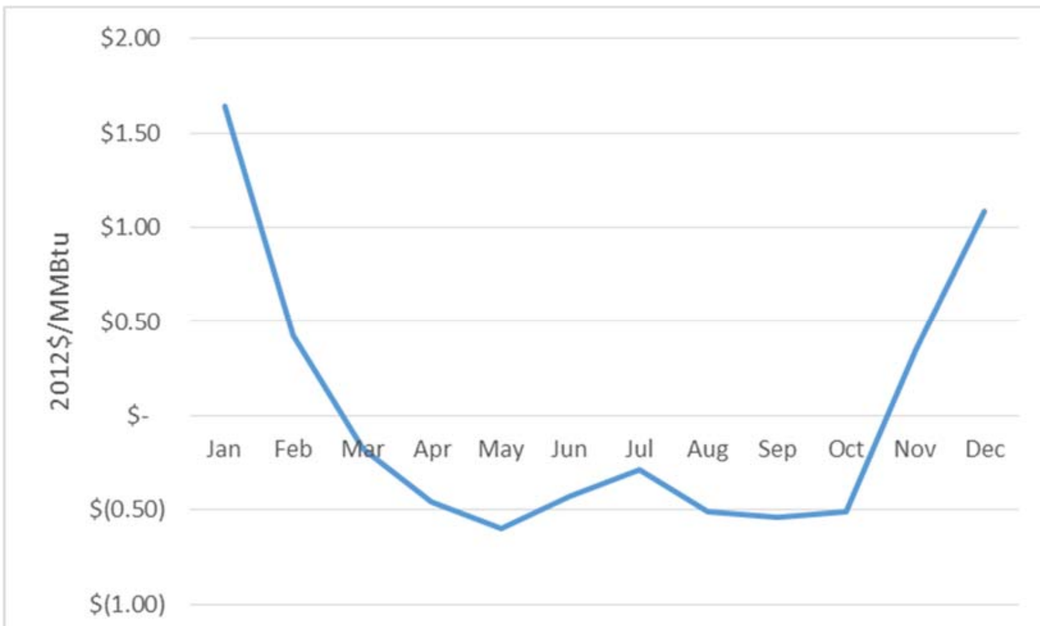

Figure 3. Monthly Algonquin Basis added to Henry Hub price.

Northern New England Basis

The Algonquin Citygate price provides a reasonable proxy for delivered natural gas prices for generators in southern New England. However, natural gas-fired generators in northern New England (Maine, New Hampshire and Vermont) face additional expense due to additional distance from inexpensive shale gas supplies to the southwest. The NMM forecast of this additional basis is $0.53/MMBTU on an annual average basis, with seasonal range of $0.32 - $0.80/MMBTU (see Figure 7). The forecast is based on backhaul usage rates on the Maritimes and Northeast Pipeline and Portland Natural Gas Transmission System short term reservation rates.

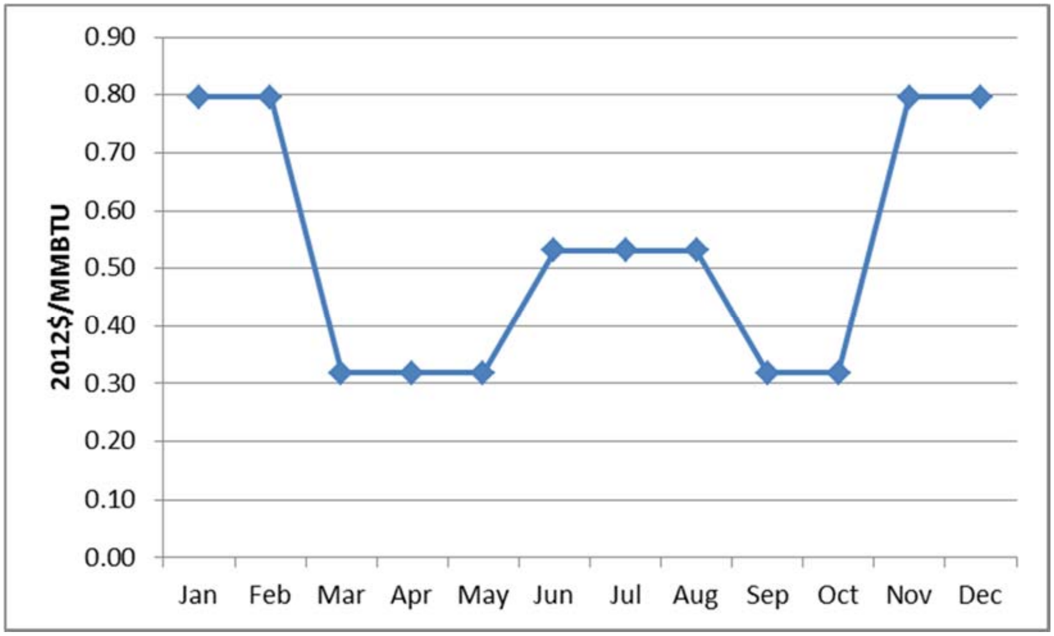

Figure 7: Northern New England Basis Differential to Rest of New England (Algonquin Citygate)

Peaking Unit Adder

Some units are assumed to pay above the monthly average price for delivered natural gas because they tend to only be dispatched on peak days when the daily gas price is likely higher. Our assumptions are summarized in Table 4.

Natural Gas Delivery Class	**Fuel Adder (2012$/MMBTU)**	**Resources in Class**
Peaking	$0.81	New Haven Harbor Units 2-4 (151MW); Androscoggin Energy Center CT03 (51MW); Swanton Peaking Generation Project #10 (40MW); Algonquin Windsor Locks (38MW); Lowell Cogeneration #GEN1-2 (32MW); Capital District Energy Center STG (29MW); Waters River #1 (20MW); Pawtucket Power #1 (20MW); 15 smaller units totaling 33MW.
Super Peaking	$1.58	Devon 11-14 (161MW); Cleary Flood #9a (106MW).
Standard (Non-Peaking)	$0.00	All Remaining units.

Table 4: Natural gas price adders for peaking units

Oil Prices

Oil prices are based on the 2015 AEO reference case. Specifically, we use Jet Fuel, Distillate Fuel Oil and Residual Fuel Oil prices for the Electric Power sector as inputs to the model. The prices used in the Reference Cases are shown in Figure 8.

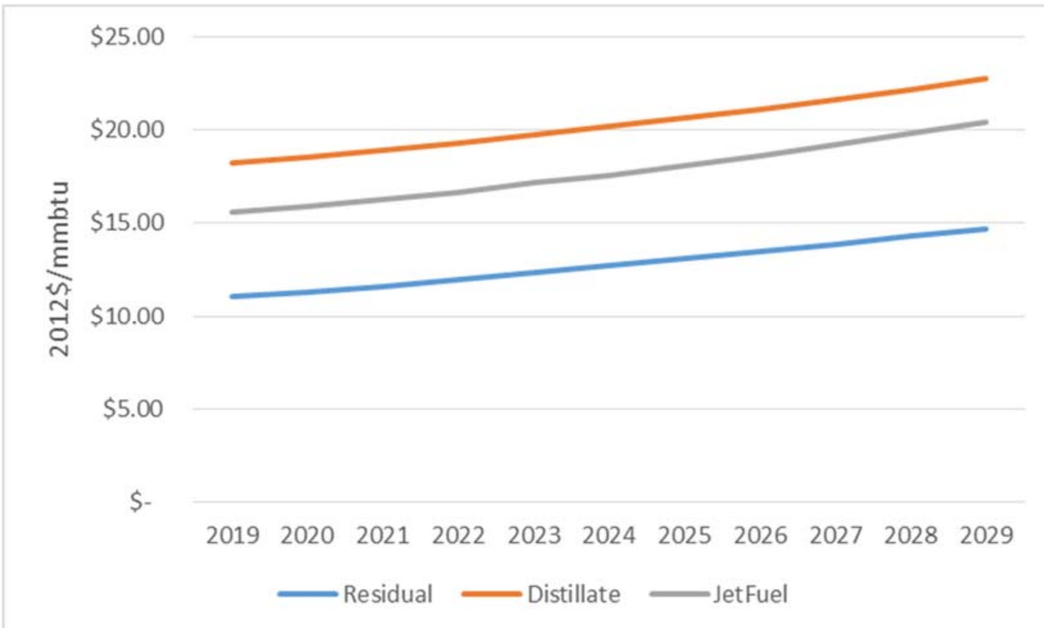

Figure 4. Oil price forecast.

D. Emission Prices

The NMM incorporates emission prices into the production cost and commitment/dispatch of units in the model. We incorporate prices for CO_2, NOx, and SO_2 into the NMM. Our specific assumptions are described below.

Greenhouse Gas Emissions

Pricing carbon emissions affects New England electric energy prices by increasing the variable costs of fossil fuel-fired generators. For our Reference Case, we assume that the Regional Greenhouse Gas Initiative (RGGI) program continues for current RGGI states, including all New England states. Starting in 2020, the implementation of federal carbon regulation is assumed to create uniform CO_2 prices across North America.

RGGI allowance prices have been minimal since the program began in 2009 because actual CO_2 emission levels have fallen well below the initial program caps. On February 7, 2013 the RGGI states announced their commitment to an Updated Model Rule that tightened caps significantly in 2014. A RGGI-commissioned study of the Updated Model Rule projects that emission allowance prices will rise from about $4 (2010$) per ton in 2014 to over $10 (2010$) per ton by 2020. The NMM incorporates this updated outlook on RGGI allowance prices. RGGI auction results to-date have benchmarked well to the Updated Model Rule forecast.

Federal policy regarding greenhouse gas emission remains a potential, though uncertain, outcome. Recently the EPA released its Clean Power Plan, which aims to cut carbon emissions from existing power plants and enable the U.S. to reduce carbon emissions from the power sector by 32% below 2005 levels. However, this rule is still subject to numerous lawsuits. No specific analysis of the Clean Power Plan was used to forecast CO_2 prices. Instead, the NMM assumes that a national CO_2 pricing program is implemented in 2020 as forecast in the "Low" case of Synapse Energy Economics, Inc.'s 2015 Carbon Dioxide Price Forecast.[10]

Figure 9 below shows the resulting assumed CO_2 prices throughout the study period.

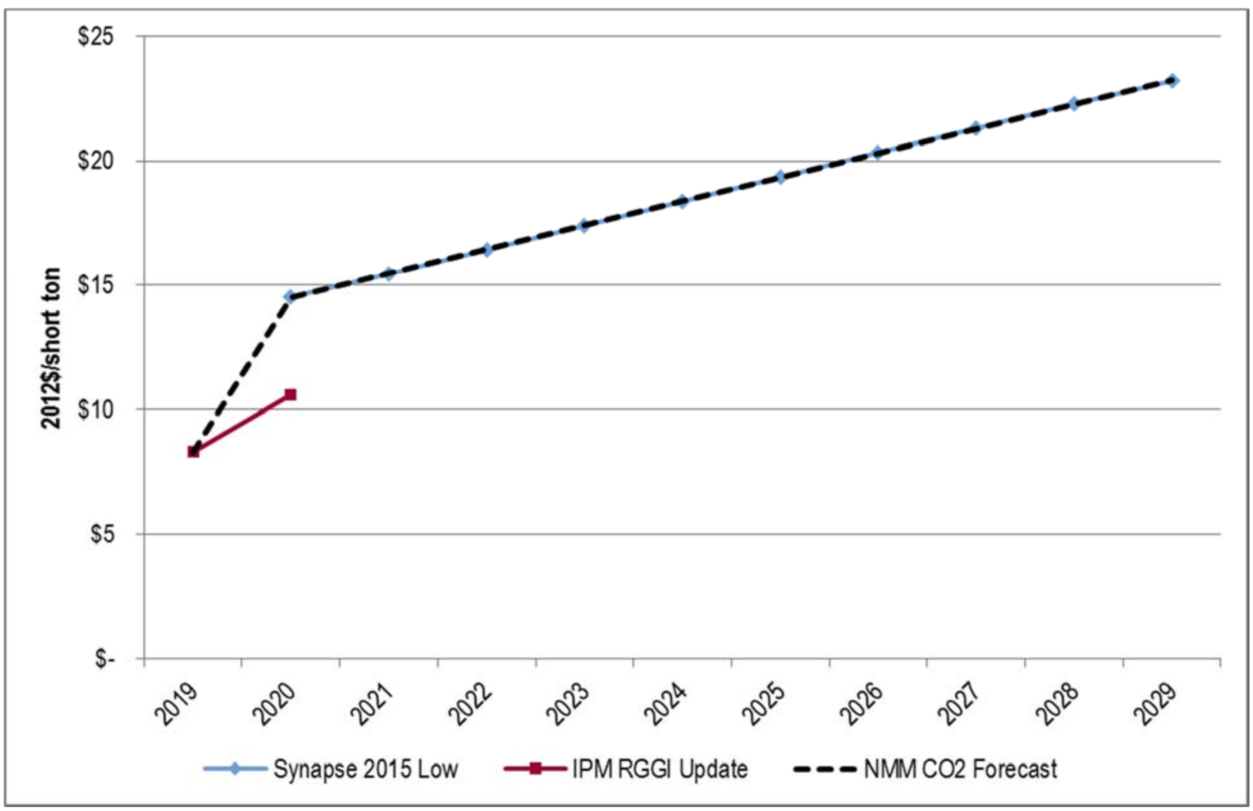

Figure 5. CO_2 price forecast.

[10] 2015 Carbon Dioxide Price Forecast, Synapse Energy Economics, March 3, 2015.

In addition, until 2020, our Reference Case CO_2 carbon prices in Quebec reflect the EPIS default prices for California and Quebec. Because Quebec's resources are almost entirely hydro and wind, this is expected to have little impact on New England resource dispatch.

NOx and SO_2 Emissions

NOx and SO_2 emission prices are a relatively minor component of market prices in New England due to the low emission rates of marginal generators (mostly gas-fired units). We developed our forecast of prices based on the 2013 Avoided Energy Supply Cost (AESC) study, which assumes zero SO_2 allowance prices and $27.01/ton (2012$) NOx allowances.[11]

We assume that the onset of national carbon pricing in 2020 will eliminate any residual NOx and SO_2 prices. Most generators in Vermont, New Hampshire, and Maine are assumed to pay no price for NOx and SO_2 emissions.

E. Retirements

The only unit retirements in the NMM modeling for the Reference Case are those that have already delisted in the FCA or those that have announced plans to retire (such as the Pilgrim nuclear plant). For the Reference Case, we assume other existing units remain online through the study period.

F. Renewable additions

Renewable energy projects assumed in the Reference Case include:

- Existing and operational projects.
- Projects currently under construction, such as SunEdison, Inc.'s Oakfield Wind Project.
- Announced projects with contracts for project output, such as EDP Renewables' Number Nine Wind Farm.
- Additional renewable energy resources necessary to meet established RPS goals throughout the study period.

New England renewable generation is an output of the Daymark New England renewable energy credit (REC) Model. We used the Winter 2015 REC Model built on the same demand forecast as discussed above. Massachusetts' recently-announced program to install 1,600 MW of solar by 2020 was also incorporated in the buildout.

The Winter 2015 REC Model incorporates recent changes in the Connecticut RPS program, which phases out the qualification of biomass resources. We have assumed that Maine will be able to satisfy its RPS going forward with biomass facilities that are already online. Vermont's new RPS appears to be significantly more lenient in its requirements than the other states as it has a low

[11] AESC 2013. http://www.synapse-energy.com/Downloads/SynapseReport.2013-07.AESC.AESC-2013.13-029-Report.pdf. See pp 4-2 to 4-4 (PDF pp 102-104).

ACP and allows large hydropower. For this reason we have not modeled the Maine or Vermont RPS in determining the regional RPS demand for additional renewable resources.

RPS requirements are assumed to continue increasing per their current legislated schedules. Beyond these established scheduled increases, RPS requirements are assumed to remain at a fixed percentage of demand for the balance of the study period, with growth in RPS demand tied to increases in load growth.

Since National Grid and Eversource terminated their contracts with Cape Wind in early 2015, we have assumed that Cape Wind will not be built.

Figure 10 depicts the total added renewable capacity for New England states in our Reference Case through the study period.

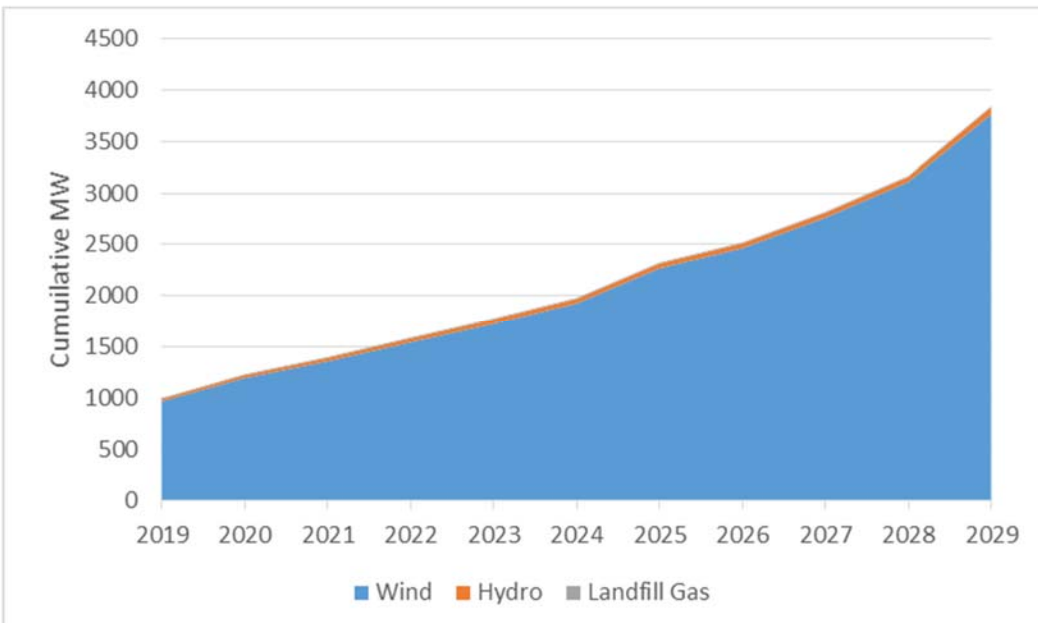

Figure 60. Cumulative additions of generic renewable generation capacity.

Distributed solar assumptions

The Reference Case includes a forecast of distributed, behind-the-meter solar. Our forecast is based on the ISO-NE distributed solar forecast.[12] The ISO-NE forecast is based on forecasts developed by each state. The ISO-NE working group then developed a method to discount estimates of future capacity installations.

Figure 11 shows the distributed solar forecast used in the NMM.

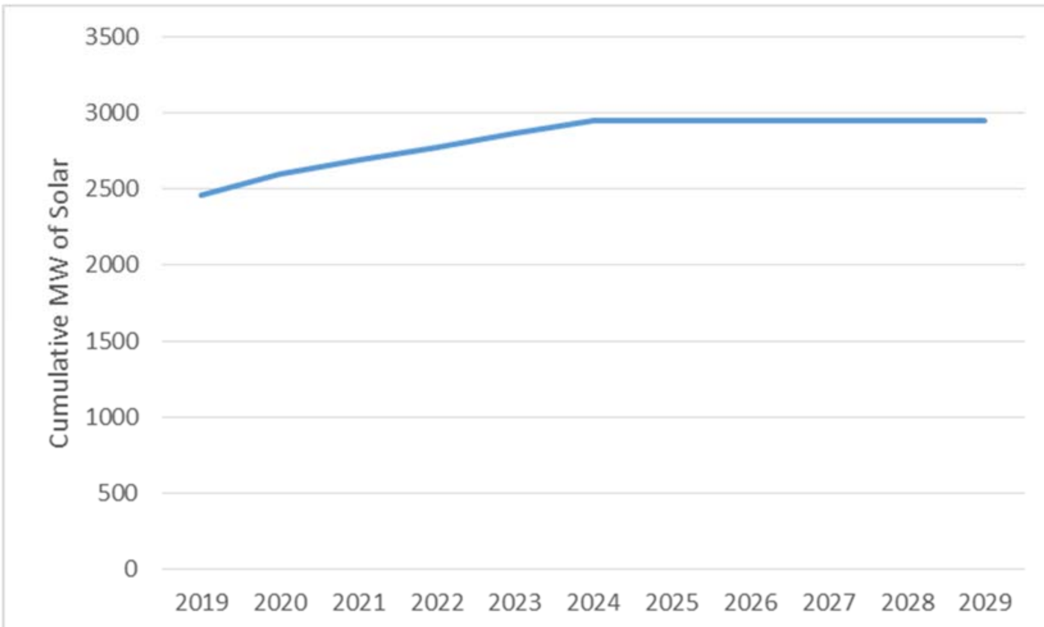

Figure 7. Cumulative additions of generic solar generation capacity.

G. Thermal Generating Unit Additions

The Reference Case includes sufficient resources to meet installed capacity requirements throughout the study period by adding generic additions of new thermal generating capacity. We determine required thermal additions by comparing the New England installed capacity requirement (NICR), net of existing tie benefits to the capacity provided by all existing and committed capacity to determine the level of capacity shortage over the study period.

The forecast of NICR is determined by using the reference case load forecast from the most recent CELT Report and applying an average pool reserve requirement. Based on the 2015 CELT the pool reserve requirement was determined to be 14.3%.

[12] The ISO-NE 2015 state-by-state solar forecast is included in the 2015 CELT Report.

The available existing and committed supply included existing resources less retirements, plus new demand-side management (passive and active), projected imports and forecasted new renewable generation. The 674 MW Footprint CCGT cleared in FCA #7 and is assumed to come online in May 2017. Resources that cleared in FCA #9 are also included, namely:

- CPV Towantic – 725 MW (2018)
- Medway Peaker SEMA-RI – 195 MW (2018)
- Wallingford 6 & 7 – 90 MW (2018)

Once these resource adjustments are made, we employ our forward capacity market model to determine the thermal buildout. On an annual basis our model estimates a capacity market clearing price using NICR and the sloped demand curve with previously cleared capacity. This clearing price is compared with estimated net CONE to determine whether or not new capacity clears the auction. This process is performed on an iterative basis to determine the long term thermal buildout.

The long term thermal buildout is met with a combination of generic natural gas fired combined cycle (CCCT) plants and generic simple cycle combustion turbine (SCCT) units. The breakdown of CCCT and SCCT build is based on net energy revenues earned by each unit type. The location of the new thermal units is based on RSP zone load growth.

Figure 12 shows the resulting assumed additions of new generic CTs and CCs.

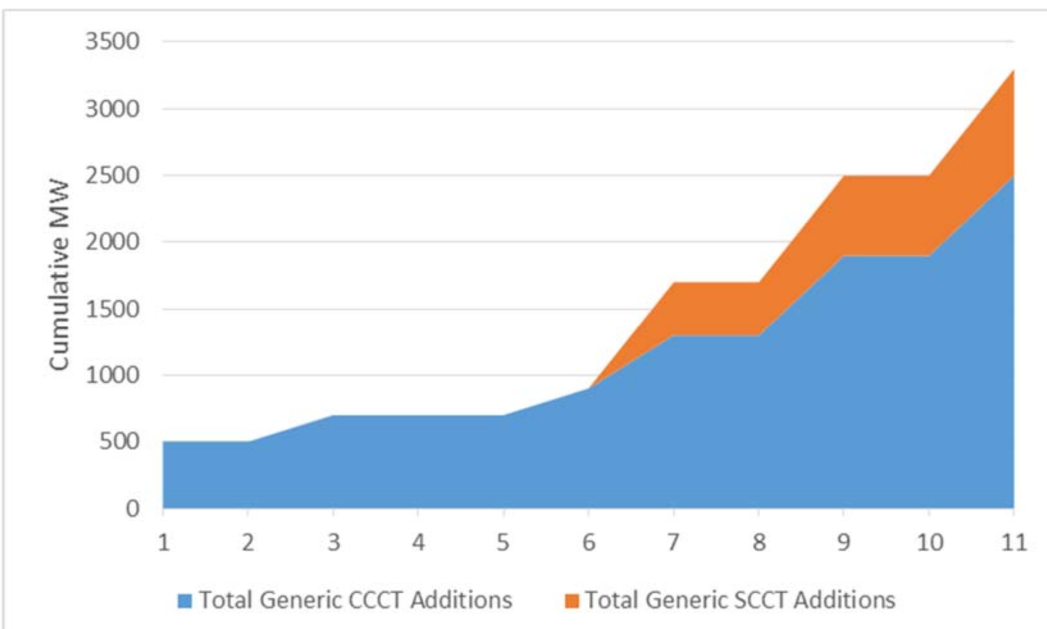

Figure 8. Cumulative additions of generic thermal generation capacity.

H. Canadian assumptions

As previously noted, the NMM models the entire Eastern Interconnect. The ISO-NE market is highly interconnected with Canadian provinces, with significant imports and exports to both New Brunswick and Quebec. These exchanges are a critical component of ISO-NE market conditions.

Our general modeling approach is the same in Canada as in New England. We have highlighted some key assumptions below.

- Load: Our assumptions on load in the Canadian provinces is based on publicly available resources, such as provincial utility load forecasts and resource plans.
- Resources: We used publicly available documents – primarily utility resource plans and annual reports – to confirm accurate representation of Canadian generators in the NMM. We incorporated any planned generator retirements or additions detailed in these public sources.
- Lower Churchill Hydro Project: Phase 1 of the Labrador hydro project, also known as Muskrat Falls, is currently under development. A portion of this project's output has been contracted to Nova Scotia and will be imported via the anticipated Maritime Link transmission project. We have incorporated this anticipated generation development
- Quebec hydro buildout: Imports from Quebec represent a key source of energy in New England. Hydro Quebec has expressed ongoing interest in developing new hydro resources for export to ISO-NE. While there are no publicly announced plans for new such resources, we consider the likelihood of development to be high. Therefore, in our modeling, we assume sufficient incremental hydro resources are added in Quebec to meet any future load growth. This keeps constant energy export levels from Quebec to New England, New York, and the other Canadian provinces.

APPENDIX G: BALANCE OF PLANT GHG MITIGATION MEASURES

Appendix G is new for Supplement No. 1

G.1 INTRODUCTION

The analysis of balance of plant efficiency measures includes evaluation of the principal components of the plant that constitute parasitic loads. A discussion of how efficiency has been incorporated into the design of the balance of plant systems is summarized in this Section.

This evaluation uses the base-case Project design parameters for natural gas firing at 50ºF and for ULSD firing at 0ºF. The GHG emissions for a Project "Base Case" are based on 3,500 hours per year of operation (average capacity factor of 40%), with 720 hours of these 3,500 hours on ULSD. This corresponds to the fuel inputs associated with the maximum rolling three-year average operating scenario for the Project to qualify as a non-baseload unit under 40 CFR 60 Subpart TTTT. The "Base Case" annual GHG emission under this scenario are 757,765 tpy.

The "Base Case" design parameters for the Project are provided below. These values do not have any manufacturer's margins or any degradation allowance included. Improvements to the balance of plant design that have been made and under study (above and beyond the "Base Case" design) are described in this Appendix.

Natural Gas Firing at 50ºF (3,187.21 MMBtu/hr HHV)

Output (gross): 346,314 kW

Output (net): 336,954 kW

Parasitic Load: 9,360 kW

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr

Heat rate (net, HHV basis): 9,459 Btu/kW-hr

ULSD Firing at 0ºF (3461.73 MMBtu/hr HHV)

Output (gross): 363,320 kW

Output (net): 357,104

Parasitic Load: 6,216 kW

Heat rate (gross, HHV basis): 9,528 Btu/kW-hr

Heat rate (net, HHV basis): 9,694 Btu/kW-hr

G.2 EVAPORATIVE COOLING

The Project design includes evaporative cooling, which may be used at ambient temperatures above 59ºF. The evaporative cooler is a device that cools the inlet air to the combustion turbine by evaporating water into the air. Evaporation of liquid water requires energy, which is obtained from the inlet air resulting in a reduction in its temperature. The combustion turbine can fire more fuel and create more power when the inlet air is cooler (and thus denser). The heat rate of the GE 7HA.02 improves by approximately 0.5% at 80ºF for full load operation, which is representative of weather conditions when evaporative cooling would be used.

Based on plant performance data provided by GE, use of evaporative cooling will improve the plant heat rate by approximately 45 Btu/kW-hr (HHV basis) for natural gas firing. Evaporative cooling will normally be used when the average temperature is greater than 59°F. The vast majority of temperatures greater than 59°F will normally occur during the months of May through September. Based on the projected seasonal operation of the Project, it is expected that approximately 27% of Project operating hours will occur between May and September, and the ambient temperature exceeds 59°F for about 75% of the hours between May and September. Combining these expected values, it is expected that approximately 20% of plant operating hours will involve use of evaporative cooling.

With an improvement in heat rate of 45 Btu/kW-hr during use of evaporative cooling during 20% of operating hours, the overall average heat rate improvement for all hours is expected to be 9 Btu/kW-hr. To quantify the GHG mitigation, this heat rate mitigation is conservatively applied to only the natural gas-firing portion of the base case since the bulk of ULSD operation (for a base case ULSD firing amount of 720 hours per year) is expected to be occur during the colder months. The GHG mitigation of this reduction in heat rate is estimated as follows.

Natural Gas Firing at 50ºF (346,314 kW gross output, 2780 hours per year)

Heat rate improvement (HHV basis): 9 Btu/kW-hr = 0.009 MMBtu/MW-hr

(0.009 MMBtu/MW-hr)(119 lb GHG/MMBtu) = 1.07 lb GHG/MW-hr

GHG savings: (346,314 kW gross output)(2780 hours)(1.07 lb GHG/MW-hr)/(1,000 kW/MW)/(2,000 lb/ton)

= **515 tpy GHG**

G.3 EXHAUST GAS BACKPRESSURE

Backpressure is a term that is used for the friction and obstacles the exhaust flow encounters when flowing from the turbine outlet to the stack exit. Overcoming this friction and the obstacles to airflow consumes energy, which reduces the amount of electric power the turbine can produce. Minimizing friction and obstacles within other design constraints is an important aspect of gas turbine design.

The energy necessary to overcome friction and obstacles is accounted for in the gross power output values listed above. Friction is minimized by optimizing the gas path velocity, minimizing the number of bends in the gas path and avoiding sharp transitions for the bends that cannot be avoided. The Project exhaust flow path has only one necessary bend, which is the transition from the horizontal flow through the turbine to the vertical flow out the stack. A smooth bend has been designed for this transition. The exhaust velocities are optimized based on the SCR design and the selection of a 25-foot stack diameter to minimize friction losses to the extent practicable.

The air pollution control equipment, which includes the SCR and oxidation catalyst systems, are necessary exhaust path components to meet LAER and BACT requirements. However, these components do create additional backpressure. One design option that was considered, but is not included in the base-case design, is a low pressure drop SCR design that has been offered by GE. The current base-case SCR design has 20 inches of backpressure. GE does offer a 12-inch SCR backpressure design, but the equipment capital cost increase for this low backpressure pressure option is $3,800,000. The incremental installation costs would increase the low backpressure design penalty to approximately $4,500,000. The low backpressure pressure option would decrease the gas-firing heat rate by approximately 33 Btu/kW-hr net (i.e., the net heat rate for natural gas firing at 50ºF would improve from 9,459 Btu/kW-hr net to 9,426 Btu/net kW-hr net. However, this small heat rate improvement was determined to not warrant such a large capital cost addition ($4.5 million). Therefore, the base-case and as-proposed designs are based on the 20-inch backpressure SCR, as reflected by the gross power output and heat rate values above.

G.4 NATURAL GAS COMPRESSOR AND GAS REHEATING

G.4.1 Description of Base Case Natural Gas Compressor

The type of natural gas compressor assumed for the “Base Case” design is a reciprocating compressor. In a reciprocating compressor, an electric motor powers a crankshaft that moves pistons contained within cylinders. The power provided to the pistons compresses the natural gas inside the cylinder, and compressed natural gas is then discharged from the cylinders.

A reciprocating compressor was used for the Project “Base Case” in order to identify the parasitic load for a candidate compressor type. The final selection of the type of compressor will not occur until an EPC contractor has been selected, and the contractor has progressed with the engineering work and solicited bids for the equipment.

An alternate compressor design that can improve gas compressor efficiency is a positive displacement flooded screw compressor with a “slide valve.” This compressor option will be evaluated by the EPC contractor as part of identifying the optimal gas compressor for the Project.

G.4.2 Base Case Gas Compressor Parasitic Load

The kW of parasitic compressor work that was included in the ”Base Case” design was 2,720 kW. This value of 2,720 kW was actually used as a constant assumed parasitic load over all gas firing hours to account for either compression or dew point heating of the gas depending on the gas pipeline pressure. The gas compressor is only required when gas pipeline pressure drops below the minimum pressure required for the turbine. The refined analysis of average parasitic compressor load based on historical gas pipeline pressures is provided in Section G.4.3 below.

G.4.3 Gas Compressor Loads Based on Historical Pipeline Pressures

Historical hourly supply pressure data have been obtained from Algonquin Gas Transmission (AGT) for a two year period (June 2014 through May 2016). Based on these data, the average hours per year when the gas supply pressure falls below the minimum required for turbine operation (582 psig) is 2,435 hours per year. These 2,435 hours per year typically occur during daytime and evening hours when overall energy demands are greater. Therefore, since the hours per year when gas compression is required (2,435) is less than the total base case gas firing hours per year (2,780), we have conservatively assumed for purposes of the parasitic load analysis that gas compression will be required for 2,435 of the 2,780 base case gas firing hours.

Table G-1 provides a summary of the average kW parasitic gas compression average work (kW) and energy (MW-hr) based on the historical AGT gas pipeline supply pressures. This analysis incorporates the hourly actual gas pipeline pressure over the two-year period and predicts the actual parasitic load for each hour based on the compressor type.

Table G-1: Natural Gas Compressor Energy Analysis Based on Historical Gas Pipeline Supply Pressures

Compressor	Average Load over 2,780 hours of “base case” gas-firing (kW)	Annual MW-hrs for Gas Compression	Annual MW-hr savings for Mitigation Option
Reciprocating Compressor (Base Case)	448.0	1,245.5	--
Flooded Screw Compressor with Slide Gate (Mitigation Option under Consideration)	419.9	1,167.3	78.2

The GHG mitigation for the flooded screw compressor with the slide gate option is calculated as follows, using the "base case" gas-firing heat rate of 9,203 Btu/kW-hr (gross, HHV basis).

Natural Gas Firing at 50ºF (2,435 hours per year with gas compression)

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr = 9.203 MMBtu/MW-hr

(9.203 MMBtu/MW-hr)(119 lb GHG/MMBtu) = 1,095.2 lb GHG/MW-hr

GHG savings: (78.2 MW-hrs/year)(1095.2 lb GHG/MW-hr)/(2000 lb/ton) = **43 tpy GHG**

G.4.4 Natural Gas Reheating

When natural gas pipeline pressures are above the upper limit of the optimal pressure for the combustion turbine, the pressure must be reduced. Reduction in gas pressure causes gas cooling, which can cause the gas to drop below its dew point and liquid water droplets can condense (depending on the gas moisture content). In cases when the potential exists for liquid water droplets to form, the gas must be heated above its dew point in order to protect the gas turbine components. Therefore, the Project "Base Case" design also includes an electric gas heater. The gas heater would normally not be used during periods of low gas pressure, since the compressor itself causes heating of the gas; however, some dew point heating can be needed at times of gas compression.

The Project "Base Case" parasitic load analysis used a constant parasitic load of 2,720 kW to account for all compression and/or dew point heating demand for the 2,780 hours of natural gas firing in the "Base Case". These parasitic load calculations have been refined using historical hourly supply pressure data obtained from AGT. The average parasitic load for electric dew point heating has been calculated using this hourly AGT pressure data for the two year period June 2014 through May 2016. Based on these data, the average expected parasitic load for electric dew point heating is 547.2 kW over the 2,780 hours of base case gas firing.

Use of waste heat from the flue gas for dew point heating was evaluated and determined to not be justified on the basis of cost. Dew point heating using waste heat from the flue gas would require installation of a glycol heating loop to capture and transfer heat from the flue gas to the dew point heater. This glycol heating loop has been estimated to have an installed capital cost in excess of $1,000,000, which was determined to not be justified for the Project.

G.5 ELECTRIC MOTORS (ASIDE FROM GAS COMPRESSOR)

Aside from the natural gas compressor, the design electric motor load for the natural gas 50ºF case is 4,301 kW, and for the ULSD 0ºF case is 3,722 kW. The largest electric motor load is for the SCR dilution air fan (2,391 kW for the natural gas 50ºF case and 1,080 kW for the 0ºF ULSD case). The SCR dilution air fan is used to draw in ambient air to cool the flue gas to the maximum SCR operating temperature of 900ºF. Due to the lower turbine exhaust and ambient temperatures for the ULSD 0ºF case, less dilution air is needed for this case. In addition to this largest electric motor load, there are several dozen other electric motors used primarily to power various pumps and fans to provide system cooling and lubrication.

The base-case electric motor design is based on motors in compliance with the Energy Policy Act of 1992 (EPAct). EPAct established minimum efficiency levels for electric motors. The EPAct motor efficiencies have been used to establish the base-case parasitic loads identified above, A more efficient class of electric motors is available than specified in EPAct, NEMA premium high-efficiency motors. A review of Project electric motors indicates that an overall aggregate efficiency improvement of 1.05% can be achieved through specification of NEMA premium high-efficiency for all electric motors. The electric motors for all Project parasitic loads are proposed as NEMA premium high-efficiency motors. With an aggregate efficiency improvement of 1.05%, the as proposed electric motor load for the natural gas 50ºF case is reduced from 4,301 kW to 4,256 kW and ULSD 0ºF case is reduced from 3,722 kW to 3,683 kW.

One other design item with respect to control of electric motors related to efficiency is the potential use of variable frequency drives (VFD). VFD uses frequency and voltage to control electric motor at partial loads, which improves motor efficiency at partial loads. However, when ISO-NE dispatches the Project to operate, it is expected that Project operation will be either at or near full load, so electric motors will typically be running at full speed and a meaningful efficiency benefit of VFD is not expected. Therefore, VFD drives have not been incorporated into the as-proposed design. The use of all NEMA premium high efficiency motors typically operating at full speed when they operate is consistent with use of all reasonable measures to mitigate GHG emissions.

G.6 FUEL GAS PERFORMANCE HEATING

One additional balance of plant efficiency improvement measure that was considered was the inclusion of fuel gas performance heating using waste heat from the flue gas. Incoming natural gas (fuel gas) can be heated to 425°F in order to improve plant heat rate using waste heat from the flue gas. A net heat rate improvement of about 90 Btu/kWh-HHV at ISO conditions can be obtained by implementing performance fuel gas heating. This is conceptually similar to the dew point heating of natural gas discussed above, but the natural gas is heated to a more significant degree such that the plant heat rate is improved.

Use of waste heat for fuel gas performance heating was evaluated and also determined to not be justified on the basis of cost. Fuel gas performance heating using waste heat from the flue gas would require installation of the same glycol heating loop discussed above to capture and transfer heat from the flue gas. This glycol heating loop has been estimated to have an installed capital cost in excess of $1,000,000, which was determined to not be justified for the Project (either for dew point heating and/or for fuel gas performance heating).

G. 7 ELECTRIC TRANSFORMER

The electric transformer increases the voltage of the electricity as generated to the transmission voltage. When voltage is increased with transformers, a small fraction of the electric energy is lost in the form of heat. Transformer efficiency is related to a transformer design parameter known as impedance. The percentage impedance of a transformer is the voltage drop on full load due to the winding resistance and leakage reactance expressed as a percentage of the rated voltage. The normal design range of power plant scale transformers is 7-12%. The Project “Base Case” transformer design is based on an impedance of 9%. With an impedance of 9%, the Project “Base Case” transformer power loss for the natural gas 50ºF case is 1,749 kW, and for the ULSD 0ºF case is 1,776 kW.

If the design impedance is reduced, the transformer losses can be reduced. Lower impedance, however, results in higher available fault duty (short-circuit current). As part of the electrical interconnection process, a System Impact Study has been completed to evaluate the impact of the Project on the Eversource transmission system, including the short-circuit fault duty contribution from the Project. Based on using a 9% impedance GSU transformer, the System Impact Study found that the 345-kV circuit breakers in the adjacent Eversource substation reached 97% of their maximum short-circuit fault duty rating. Due to equipment and personnel safety issues associated with high voltage circuit breakers exceeding their maximum interrupting capability, lower impedance transformers have been found to be not feasible due to high secondary fault currents and the need for circuit breaker replacements. Lower impedance transformers have been dropped from consideration for GHG mitigation.

G.8 SCR AMMONIA VAPORIZATION

The Project "Base Case" design included an electric heater for vaporizing the aqueous ammonia solution used as the SCR reagent. The design parasitic load for this electrically heated ammonia vaporizer for the natural gas 50ºF case is 196 kW, and for the ULSD 0ºF case is 340 kW.

The Project has determined that it is feasible to use of hot CTG exhaust gas to vaporize ammonia in lieu of continuous use of an electric heater. Since the turbine exhaust gas temperature will be in excess of 1,200ºF, the use of hot exhaust gas to vaporize aqueous ammonia vaporizer will require the use of high alloy materials and/or a cooling air system. The overall GHG benefit of this reduction in parasitic load is as follows:

Natural Gas Firing at 50ºF (2780 hours per year)

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr = 9.203 MMBtu/MW-hr

(9.203 MMBtu/MW-hr)(119 lb CO2e/MMBtu) = 1,095.2 lb CO2e/MW-hr

CO2e savings: (196 kW)(2780 hours)(1095.2 lb CO2e/MW-hr)/(1000 kW/MW)/

(2000 lb/ton) = **298.4** tpy CO2e

ULSD Firing at 0ºF (720 hours per year)

Heat rate (gross, HHV basis): 9,528 Btu/kW-hr = 9.528 MMBtu/MW-hr

(9.528 MMBtu/MW-hr)(162.85 lb CO2e/MMBtu) = 1,551.6 lb CO2e/MW-hr

CO2e savings: (340 kW)(720 hours)(1551.6 lb CO2e/MW-hr)/(1000 kW/MW)/

(2000 lb/ton) = **189.9** tpy CO2e

Total CO2e Savings for Both Fuels: **298.4** tpy + **189.9** tpy = **488.3** tpy CO2e

Under this scenario, the primary operational ammonia vaporization duty would be accomplished with the exhaust gas heated system. However, the Project would still include an electrically heated ammonia vaporizer in order for the unit to achieve rapid stack NO_x emissions compliance during startups. Accordingly, in order to adjust the projected CO2e savings for use of the electric vaporizer during startups, the total CO2e savings would be reduced by 3%. The final estimated value for CO2e savings from the inclusion of the exhaust gas heated ammonia vaporizer system is **474** tpy CO2e.

G.9 MISCELLANEOUS AUXILIARIES

The Project base-case design includes an allowance of 364 kW of parasitic losses for miscellaneous plant auxiliaries. These auxiliaries include an allowance for various minor components such as lighting (22 kW allowance), computer systems, lube oil heating and other small power consumption sources. The Project will review the design allowance and equipment specifications for miscellaneous auxiliaries and select the most efficient commercially available equipment and systems, including LED lighting.

G. 4 SUMMARY OF PARASITIC LOAD ANALYSIS

The parasitic load evaluation and summary of balance of plant mitigation measures is provided in Table G-2 below.

. **Table G-2: Summary of Mitigation - Balance of Plant Efficiency Evaluation**

Item	Natural Gas – 50ºF 2,780 hours/year	ULSD – 0ºF 720 hours/year	CO2e Emissions (tpy)		Percent Reduction	
			Adopted	Under Study	Adopted	Under Study
Prime Mover – GE 7HA.02 CTG (or equivalent H-class turbine)	Gross Output 346,314 kW Base Case	Gross Output 363,320 kW Base Case	757,765 (Base Case)		--	
Evaporative Cooling (adopted)	Heat rate improvement of 9 Btu/kW-hr Equivalent reduction expressed as parasitic load reduction = 339 kW	Benefit conservatively ignored for ULSD firing	515		0.07%	
Fuel Gas Performance Heating (not adopted)	Heat rate improvement of 90 Btu/kW-hr Equivalent reduction expressed as parasitic load reduction = 3,420 kW	NA				
Gas Compressor Selection (under study)	2,720 kW Base Case allowed for total parasitic load of gas compression and dew point heating Revised analysis indicates 448 kW average expected load for 2,780 compression hours with base case compressor 419.9 kW average load with a mitigated flooded screw compressor	NA		43		0.006%
Gas Dew Point Heating Using Waste Heat (not adopted)	Base Case was 2,720 kW for parasitic load of both compression and dew point heating. Revised analysis indicates 547.2 kW average expected electric dew point load for 2,780 "base case" gas-firing hours.	NA				
Electric Motors Aside from Gas Compressor NEMA (premium high efficiency motors adopted)	4,301 kW based on EPAct motors (Base Case) With NEMA premium high efficiency motors the load is reduced to 4,256 kW	3,722 kW based on EPAct motors (Base Case) With NEMA premium high efficiency motors the load is reduced to 3,683 kW	90		0.01%	
Electric Transformer Loss (lower impedance transformers not adopted)	1,749 kW based on Z = 9	1,776 kW based on Z = 9				
	Lower impedance transformers found to be not feasible due to high secondary fault currents and the need for circuit breaker replacements. Lower impedance transformers have been dropped from consideration for GHG mitigation.					

<table>
<tr><th rowspan="2">Item</th><th rowspan="2">Natural Gas – 50ºF
2,780 hours/year</th><th rowspan="2">ULSD – 0ºF
720 hours/year</th><th colspan="2">CO2e Emissions (tpy)</th><th colspan="2">Percent Reduction</th></tr>
<tr><th>Adopted</th><th>Under Study</th><th>Adopted</th><th>Under Study</th></tr>
<tr><td rowspan="2">SCR Ammonia Vaporizer (adopted)</td><td>196 kW based on electric heater</td><td>340 kW based on electric heater</td><td rowspan="2">474</td><td rowspan="2"></td><td rowspan="2">0.06%</td><td rowspan="2"></td></tr>
<tr><td colspan="2">Use of an electric ammonia vaporizer is required during startup, resulting in an average vaporizer load (spread over all operating hours) of 6 kW for gas firing and 10 kW for ULSD firing.</td></tr>
<tr><td>Miscellaneous Auxiliaries (highest efficiency alternatives adopted)</td><td>364 kW</td><td>364 kW</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Total</td><td>Current total parasitic load for gas firing at full load 50 deg F incorporating all adopted measures = 448+ 547+4,256+1,749 +6+364-339 = 7,031 kW (25% improvement over Base Case value of 9,360 kW)</td><td>Current total parasitic load ULSD firing 0 deg F incorporating all adopted measures = 3,683+1,776 +10+364 = 5,833 kW (6% improvement over Base Case value of 6,216 kW)</td><td>1,079</td><td>43</td><td>0.14%</td><td>0.006%</td></tr>
</table>

The design data for the adopted efficiency improvement measures are as follows:

<u>Natural Gas Firing at 50ºF (3,187.21 MMBtu/hr HHV)</u>

Output (gross): 346,314 kW

Output (net): **339,283** kW

Parasitic Load: **7,031** kW

Heat rate (gross, HHV basis): 9,203 Btu/kW-hr

Heat rate (net, HHV basis): **9,394** Btu/kW-hr

<u>ULSD Firing at 0ºF (3461.73 MMBtu/hr HHV)</u>

Output (gross): 363,320 kW

Output (net): **357,487** kW

Parasitic Load: **5,833** kW

Heat rate (gross, HHV basis): 9,528 Btu/kW-hr

Heat rate (net, HHV basis): **9,684** Btu/kW-hr