Enbridge
Suite 600 – 890 Winter Street
Waltham, Massachusetts 02451
USA

May 25, 2018

Mr. Thomas Cushing
Permit Section Chief
MassDEP Southeast Regional Office
20 Riverside Drive
Lakeville, MA 02347

RE: *Update to Non-Major Comprehensive Plan Approval Permit Application*
Transmittal No. X266786
Application No. SE-15-027
Algonquin Gas Transmission, LLC – Weymouth Compressor Station

Dear Mr. Cushing:

Algonquin Gas Transmission, LLC (Algonquin) is providing an update to its Non-Major Comprehensive Plan Approval (Non-Major CPA) Application (Transmittal No. X266786) initially filed on October 23, 2015, and updated on September 9, 2016. The application pertains to Algonquin's proposed construction of the Weymouth Compressor Station in Weymouth, MA, as a component of its Atlantic Bridge Project (Project).

As you know, the Massachusetts Department of Environmental Protection (MassDEP) issued a proposed Air Quality Plan Approval (Plan Approval) for the Weymouth Compressor Station on March 30, 2017 and requested public comment. On July 14, 2017, in response to concerns expressed by members of the public regarding the potential impact of the Project on air quality and public health in the Weymouth and neighboring communitiesGovernor Charles D. Baker directed MassDEP and the Massachusetts Department of Public Health (MassDPH) to jointly prepare a health impact assessment, and to complete the assessment prior to the issuance of any air permit related to the Project. The health impact assessment is expected to be completed later in 2018.

Since filing the last update to the application in September 2016, Algonquin has continued the design and engineering process of the Weymouth Compressor Station and has analyzed the resulting changes in estimated potential emissions. The attached, updated application describes this work and the resulting changes in potential emissions. In summary:

1. Algonquin refined the estimates of gas release volumes to accord with the current design of the facility, rather than the previously used model facilities, and to account for Algonquin's elective implementation of best management practices, including pressurized holds, to reduce gas releases from operation and maintenance activities.
2. Algonquin revised the natural gas quality data based on an analysis of natural gas quality across the entire Enbridge gas transmission system.
3. Algonquin incorporated revised vendor guidance for turbine emissions during startup, shutdown, and transient events.

Therefore, this submittal updates the potential emissions of the Weymouth Compressor Station to account for refinements to estimates of maximum potential emissions from piping components, gas releases, and the turbine. The revised vendor guidance for emissions during startup and shutdown events result in slight increases in annual potential to emit estimates for NO_X, CO and VOC from the turbine. The refinements to potential gas release volumes and gas quality data result in a reduction in the annual potential to emit estimate for VOC from fugitive sources from 21.32 tons per year (tpy) to 5.76 tpy.[1]

The updated application includes a summary of the updated potential emissions for the Weymouth Compressor Station site as Table 3-16 at p. 3-23, copied here:

Total Potential Emissions from the Site

Pollutant (tpy)	Combustion Sources (tpy)	Fugitive Sources (tpy)	Parts Washer, Separator Vessels, and Tanks (tpy)	Total Project Emissions (tpy)
NO_X	~~18.38~~ 18.45	--	--	~~18.38~~ 18.45
CO	~~29.69~~ 30.20	--	--	~~29.69~~ 30.20
VOC	~~4.11~~ 5.49	~~21.32~~ 5.76	1.70	~~27.13~~ 12.95
$PM_{10}/PM_{2.5}$	2.73	--	--	2.73
SO_2	5.60	--	--	5.60
CO_2e	47,430	~~13,857~~ 4,607	53	~~61,340~~ 52,090
Total HAPs	~~0.97~~ 1.49	~~1.27~~ 0.27	0.08	~~2.32~~ 1.84

The following table identifies and cross-references the updates in the application to requested updates to the draft Plan Approval, along with a summary explanation for the update. A markup of the March 30, 2017 draft Plan Approval is enclosed as Attachment H to the updated application.

Description of Plan Approval Update	Location in Draft Plan Approval	Location in Updated Application (clean, highlighted version)	Explanation of Update
Update to the turbine monthly and annual hour limits on transient events.	Section 1.B. (p. 3)	p. 3-7, Section 3.1.4	Updated vendor guidance for turbine transient event emissions.
Update to the shutdown duration of the turbine from 3.5 minutes to 8.5 minutes.	Section 1.B. (p. 3)	p. 3-6, Section 3.1.3.2 & Table B-1Ag in Attachment G	Updated vendor guidance for turbine shutdown duration.
Recommended language change for consistency in LDAR Program Requirements.	Section 1.B. (p. 4)	-	Subpart OOOOa provides comprehensive monitoring, recordkeeping, reporting, and repair requirements for fugitive components at a natural gas transmission compressor station. Subpart OOOOa allows for use of

[1] The reduction in the annual potential to emit estimate for VOC from fugitive sources reflects a reduction in the annual potential to emit estimate for VOC from gas releases from 18.93 tpy to 3.54 tpy, as well as a reduction in the annual potential to emit estimate for VOC from piping components from 2.38 tpy to 2.21 tpy.

			either Method 21 or optical gas imaging. This language change provides consistency with the requirement in Section 8, Table 12, Condition 4.
Update description of venting associated with routine operations	Section 1.B. (p. 4)	p. 3-19, Section 3.8.2	Algonquin will implement best management practices, including pressurized holds, to minimize case venting.
Update to predicted pollutant impact concentrations	Section 1.C., Table 4 & Table 5 (pp. 9-10)	Updated modeling report	Dispersion modeling was updated with latest version of AERMOD, meteorological data, and background monitoring data; updated maximum potential to emit calculations; and the Fore River Energy black-start engines.
Update to emission limits for EU1 under Standard Operating Conditions.	Section 3.A., Table 8A (p. 13)	p. 3-20, Table 3-13 & Table B-1Aj in Attachment G	Updated vendor guidance for turbine potential startup/shutdown emissions - monthly and annual.
Update to emission limits for EU2 under Standard Operating Conditions.	Section 3.A., Table 8A (p. 13)	p. 3-19, Section 3.8.2, p. 3-21, Table 3-14, & Table H-1Ba in Attachment G	Algonquin reduced the estimates of gas release volumes based on engineering design for the proposed Weymouth Compressor Station and electively implementing best management practices, including pressurized holds, to reduce gas releases from operation and maintenance activities; and Algonquin updated natural gas quality data based on an analysis of natural gas quality across the entire Enbridge gas transmission system.
Update to EU1 emission limits, and monthly and annual hour limits, for Transient Events.	Section 3.A., Table 8C (p. 14)	p. 3-7, Section 3.1.4, p. 3-9, Section 3.1.6, p. 3-10, Table 3-7, & Table B-1Aj in Attachment G	Updated vendor guidance for turbine transient event emissions.
Update to EU1 emission limits for Startup/Shutdown.	Section 3.A., Table 8D (p. 15)	p. 3-6 to 3-7, Table 3-4 and Table 3-5, p. 3-10, Table 3-8, & Table B 1Af, Table B-1Ag, and Table B-1Aj in Attachment G	Updated vendor guidance for turbine startup/shutdown emissions.

Recommended language change to clarify the limits in the referenced tables apply only to the turbine.	Section 3.A., Table 8A, 8B, 8C, and 8D Notes (p. 16 and 17)	-	The emission limits in the referenced tables are for the turbine.
Clarify that transient events exclude startup, shutdown, and low temperature events.	Section 3.A., Table 8A, 8B, 8C, and 8D Note 8. (p. 17)	p. 3-7, Section 3.1.4, Footnote 6	Vendor guidance for turbine transient events.
Correct reference to LDAR monitoring requirements.	Section 3.B., Table 9, Condition No. 9. (p. 18)	-	The monitoring requirements for the LDAR program refer to Special Condition, Provision 5. Algonquin believes the correct reference should be to Special Terms and Conditions, Table 12, Conditions 4 through 6.
Remove redundant monitoring requirement for transient events.	Section 3.B.,Table 10, Condition No. 7. (p. 19)	-	This monitoring requirement appears to be the same as that required by Section 3.B., Table 10, Condition No. 4. (p. 19)
Request additional 15 days to compile actual emission calculations.	Section 3.B., Table 10, Condition No. 10. (p. 19)	-	Algonquin requests the timeline for compiling monthly records of actual emissions for each calendar month and for each consecutive 12-month period be increased from 15 days to 30 days.
Reduce the threshold for notification to MassDEP of planned blowdowns.	Section 3.B., Table 11, Condition No. 2. (p. 20)	-	Algonquin requests that the threshold for notification to MassDEP of planned blowdowns be reduced from 1 MMScf to 100,000 scf.
Correct the reference to “No stack” for EU2 to “Various”.	Section 4.C., Table 13 (p. 23)	-	EU2 is a grouping of various gas release points throughout the compressor station.

Should you have any questions regarding this application, please do not hesitate to contact me at

207-274-2607.

Sincerely,
ENBRIDGE

Kathryn A. Brown

Kathryn A. Brown
Consulting Scientist

cc: Reagan Mayces, Enbridge
Barry Goodrich, Enbridge
George McLachlan, Enbridge
Ralph Child, Mintz, Levin, Cohn, Ferris, Glovsky and Popeo, P.C.
Wendy Merz, Trinity Consultants

Enclosures

NON-MAJOR COMPREHENSIVE PLAN APPROVAL
UPDATED PERMIT APPLICATION
TRANSMITTAL NO. X266786
(REVISED MAY 2018)

Algonquin Gas Transmission, LLC > Weymouth Compressor Station
Atlantic Bridge Project

Prepared For:

Algonquin Gas Transmission, LLC
Weymouth Compressor Station
50 Bridge Street
Weymouth, MA 02191

Prepared By:

TRINITY CONSULTANTS
153 Cordaville Rd, Suite 120
Southborough, MA 01772
(508) 273-8600

Project 142201.0010

Trinity Consultants

Environmental solutions delivered uncommonly well

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

Algonquin Gas Transmission, LLC (Algonquin) is proposing to increase the pipeline size and compressor station horsepower between a receipt point on Algonquin's system at Mahwah in Bergen County, New Jersey and various delivery points on the Algonquin and Maritimes & Northeast Pipeline, LLC (Maritimes) system, including at Beverly, Massachusetts, for further transportation and deliveries on the Maritimes system. Collectively, this project is referred to as the Atlantic Bridge (AB) Project.

The AB Project will require the addition of horsepower at two existing compressor stations in Connecticut and one new compressor station in Massachusetts. The new compressor station will be located in Weymouth, Norfolk County, Massachusetts (the Weymouth Compressor Station), on a parcel Algonquin has agreed to acquire from Calpine Fore River Energy Center, LLC. The Weymouth Compressor Station will be located adjacent to an existing metering and regulating station (the Weymouth M&R Station). This application accordingly seeks a non-major comprehensive air plan (Non-Major CPA) approval for the combination of the proposed Weymouth Compressor Station and the existing Weymouth M&R Station (hereinafter referred to as the "Site").

On October 22, 2015, Algonquin and Maritimes filed an Abbreviated Application for Certificates of Public Convenience and Necessity and for Related Authorizations with the Federal Energy Regulatory Commission (FERC) for the AB Project. On May 2, 2016, the FERC issued its Environmental Assessment (EA) of the project. The FERC issued an Order Issuing Certificate for the AB Project, including the Weymouth Compressor Station, on January 25, 2017.

Algonquin is proposing to install the following emission sources at the Weymouth Compressor Station:

- A new Solar Taurus 60-7802 natural gas-fired turbine-driven compressor unit;
- A new Waukesha VGF24GL natural gas-fired emergency generator;
- A new natural gas-fired turbine compressor fuel gas heater;
- Five new natural gas-fired catalytic space heaters;
- A new remote reservoir parts washer;
- New separator vessels and storage tanks; and
- Sources of fugitive emission (piping components, gas releases and truck loading).

The Weymouth Compressor Station will be constructed approximately 100 meters from the existing Weymouth M&R Station.

The emission units at the existing Weymouth M&R Station include the following:

- One Hanover natural gas-fired heater;
- One NATCO natural gas-fired heater;
- Three Lochinvar natural gas-fired boilers; and
- Sources of fugitive emissions (piping components and gas releases).

Algonquin proposes that the Massachusetts Department of Environmental Protection (MassDEP) regard the combined operations at the Site as a single facility for air plan approval permitting purposes.

The combined potential emissions from the proposed Weymouth Compressor Station and the Weymouth M&R Station are below the MassDEP Title V permitting thresholds.

1.2. BENEFITS OF THE AB PROJECT

The AB Project will provide New England with a unique opportunity to secure a cost-effective, domestically produced, environmentally friendly source of energy to support its current demand, as well as its future growth, for clean burning natural gas. The AB Project is an infrastructure investment that expands the pipeline capacity of the existing Algonquin system, which will allow abundant regional natural gas supplies to flow reliably into New England. The AB Project will provide up to 132,705 decatherms per day (Dth/d), designed to meet the requirements of customers throughout New England.

In addition to reliability and cost benefits, the increased availability of natural gas to the region provides environmental benefits by increasing the supply of a cleaner burning fuel alternative to other traditional fuels such as biomass, coal, and fuel oils. Further, Algonquin has minimized the environmental impacts of the AB Project by proposing to install an efficient, low-emitting Solar Taurus 60-7802 natural gas turbine-driven compressor unit at the Weymouth Compressor Station. The Taurus 60-7802 turbine is designed to minimize combustion emissions through the use of state-of-the-art SoLoNO$_X$™ dry low emissions technology and an oxidation catalyst on the turbine. For this project, Solar has guaranteed nitrogen oxide (NO_X) emissions for the new unit at 9 parts per million volumetric dry (ppmvd) at 15 percent oxygen (O_2) during steady-state operation at 50-100 percent engine load for all ambient temperatures above zero degrees Fahrenheit (^oF).

1.3. AIR PERMITTING SUMMARY

The new Solar Taurus 60-7802 natural gas-fired turbine and fugitive emissions from gas releases and piping components will require a Non-Major CPA per 310 CMR 7.02(5)(a)(1) and 310 CMR 7.02(5)(a)(2). The new turbine will be subject to 40 CFR 60 Subpart KKKK, New Source Performance Standards for Stationary Gas Turbines as well as the applicable state regulations as outlined in Section 4.5 of this report. The new emergency generator will be subject to 40 CFR 60, Subpart JJJJ, New Source Performance Standards for Stationary Spark-Ignition Internal Combustion Engines and 40 CFR 63, Subpart ZZZZ, and National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. In addition, the Weymouth Compressor Station will be subject to the leak detection and repair (LDAR) requirements of 40 CFR 60, Subpart OOOOa. A review of New Source Review (NSR) requirements for the Site indicates that it will not trigger Prevention of Significant Deterioration (PSD) permitting per 40 CFR 52.21,[1] nor will it trigger permitting requirements for nonattainment areas per 310 CMR Appendix A. Details of this NSR applicability review are provided in Section 4.2 of this report.

Algonquin's Non-Major CPA application for the new turbine also covers fugitive emissions from gas releases and piping components, as well as emissions from the Weymouth M&R station. The new emergency generator at the compressor station will be operated under the Environmental Results Program (ERP) Certification requirements of 310 CMR 7.26(42) and 310 CMR 70.00; the required certification will be submitted within 60 days of commencement of operation of the emergency engine.

The new and existing natural gas-fired heaters and existing boilers are exempt from permitting per 310 CMR 7.02(2)(b)(15), since they will fire natural gas and the rated heat input of each heater is less than 10 MMBtu/hr.

---

[1] The Massachusetts Department of Environmental Protection (MassDEP) is delegated authority to implement the federal PSD program at 40 CFR 52.21.

The new parts washer, new separator vessels and storage tanks, and fugitive emissions from truck loading are exempt from permitting per 310 CMR 7.02(2)(b)(7) because potential emissions from these individual sources are less than one ton per year (tpy) for any air pollutant. These sources are therefore not identified as emission units in the application. The emissions from their operation, however, are included as part of the overall limits set for the Site.

1.4. SUMMARY OF UPDATES TO THE APPLICATION

Algonquin submits this updated Non-Major CPA application for the Weymouth Compressor Station to incorporate refinements in turbine vendor emissions estimates, compressor station design, and gas quality data, which have occurred since the previous submittal. More information regarding these refinements is provided below.

Refinements to Turbine Potential Emissions Estimates

Subsequent to the last application submittal, Algonquin received revised emissions guarantees and guidance from Solar Turbines Inc., (Solar), the manufacturer of the proposed Taurus 60-7802 natural gas-fired turbine at the Weymouth Compressor Station. The new information from the vendor:

- Revised volatile organic compounds (VOC) emissions during startup and shutdown periods;
- Revised the shutdown duration for the Taurus 60 turbine, which in turn affects the estimated pound per event (lb/event) emissions estimate; and
- Revised guidance related to estimating turbine emissions during transient events.[2]

These updates result in slight increases in annual potential to emit estimates for NO_X, CO and VOC from the turbine.

Refinements to Gas Release Potential Emissions Estimates

As described in Section 3.8.2 of this application, emissions from gas releases are estimated based on the equipment design, which dictates the volume of gas released, and the gas quality, which indicates the amount of individual pollutants (VOCs, hazardous air pollutants (HAPs), carbon dioxide equivalent (CO_2e)) in the gas. Refinements in the station design and electively implementing best management practices, including pressurized holds, have resulted in revised potential gas release volumes. With respect to gas quality, Enbridge (Algonquin's parent company) has compiled available extended gas analyses on samples of tariff-conforming pipeline quality natural gas (421 samples total) taken over the past six years across its pipeline systems. Based on statistical analyses of these data, a speciation profile of the natural gas transported through Enbridge's gas pipelines has been developed. Previous calculations submitted for the Weymouth Compressor Station were based on a smaller dataset (62 samples). The updates to potential gas release volumes and gas quality data result in a reduction in the annual potential to emit estimate for VOC from gas releases from 18.93 tpy to 3.54 tpy.

[2] Current manufacturer guidance indicates that transient events result in emissions levels between those guaranteed for $SoLoNO_X$ ™ mode and the worst-case emission rates provided for full load operation at ambient conditions less than or equal to -20 °F. Therefore, for permitting purposes, it is assumed that transient event emission rates are equivalent to the worst-case emission rates provided by the vendor for full load operation at ambient temperatures less than or equal to -20 °F.

Refinements to Potential Fugitive Emissions Estimates for Piping Components
The revised speciation profile for natural gas described above also impacts the estimate for potential fugitive emissions from piping components at the Weymouth Compressor Station. These updates result in a reduction in the annual potential to emit estimate for VOC from piping components from 2.38 tpy to 2.21 tpy.

The application forms in Attachment B have been revised to reflect these changes. Updated emissions calculations are provided in Attachment G and resulting revisions to proposed emissions limits are shown in the redline version of the draft Non-Major CPA for Weymouth Compressor Station provided in Attachment H. Additionally, the air dispersion modeling analysis for the Weymouth Compressor Station has been updated to reflect these changes and will be submitted under separate cover to the MassDEP.

1.5. APPLICATION OVERVIEW

As requested by the MassDEP, Algonquin is providing the entire Non-Major CPA application package, complete with all the sections and attachments, in this updated submittal. The following information is included:

- Section 2 – Project Overview
- Section 3 – Project Emissions Quantification
- Section 4 – Regulatory Applicability
- Section 5 – Best Available Control Technology Analysis
- Section 6 – Dispersion Modeling Analysis
- Section 7 – Noise Analysis
- Attachment A – Transmittal Form
- Attachment B – BWP AQ 02 Non-Major CPA Forms - CPA-FUEL, CPA-PROCESS
- Attachment C – Supplemental Forms - BWP AQ BACT Forms, BWP AQ Sound
- Attachment D – Figures - Site Plan, Process Flow Diagram
- Attachment E – Best Available Control Technology Analysis
- Attachment F – Noise Survey Report
- Attachment G – Detailed Emission Calculations and Manufacturer Specifications
- Attachment H – Redlined Draft Non-Major CPA for Weymouth Compressor Station

The application transmittal form (transmittal number X266786) and plan approval application fee of $2,370.00 made payable to “Massachusetts Department of Environmental Protection” was submitted in October 2015.

2.1. SITE DESCRIPTION

The existing Algonquin pipeline transports residential quality natural gas. The gas must be compressed along the pipeline to ensure efficient transportation and delivery to customers at serviceable pressures. The proposed location of the Weymouth Compressor Station is located approximately 100 meters northeast of the existing Weymouth M&R Station.

2.2. PROPOSED PROJECT DESCRIPTION

As part of the AB Project, Algonquin is proposing to install the following equipment at the Weymouth Compressor Station:

- A new Solar Taurus 60-7802 7,700 horsepower (HP) natural gas-fired turbine-driven compressor unit;[3]
- A new Waukesha VGF24GL 585 brake horsepower (bhp) natural gas-fired emergency generator;
- A new 0.23 MMBtu/hr heat input natural gas-fired turbine compressor fuel gas heater;
- Five new 0.076 MMBtu/hr heat input natural gas-fired catalytic space heaters;
- A new remote reservoir parts washer; and
- Three new separator vessels, one condensate storage tank, one lubricating oil storage tank, and one oily water storage tank.

In addition to the installed equipment, the Project will generate emissions from fugitive emission sources such as piping components, storage tank working and breathing losses, gas releases, and truck loading.

The new Solar Taurus 60-7802 turbine-driven compressor unit will be used for pipeline natural gas compression. The proposed new turbine will have a simple cycle design and will utilize an oxidation catalyst to control carbon monoxide (CO), volatile organic compounds (VOC), and organic hazardous air pollutant (HAP) emissions and will utilize dry low-NO_X (DLN) combustion technology to reduce NO_X emissions. The new turbine is subject to air permitting per 310 CMR 7.02(5)(a)(1) and 310 CMR 7.02(5)(a)(2).

The emission sources at the existing Weymouth M&R Station include the following:

- One Hanover 9.5 MMBtu/hr heat input natural gas-fired heater;
- One NATCO 6.8 MMBtu/hr heat input natural gas-fired heater;
- Three Lochinvar 1.8 MMBtu/hr heat input natural gas-fired boilers;
- Miscellaneous support equipment; and
- Sources of fugitive emissions (piping components and gas releases).

[3] All turbine horsepower ratings are provided at ISO (International Organization of Standardization) conditions, all engine horsepower ratings are manufacturers' rated output per National Electric Manufacturers Association (NEMA) standards, and all heat inputs are provided at higher heating value (HHV).

2.3. PLAN APPROVAL EXEMPT EMISSION SOURCES

The following emission sources at the Site do not require air plan approvals and, therefore, are not identified as proposed emission units in the application. The potential emissions from their operation are however included as part of the proposed potential emissions for the Site and in the modeling.

The new Waukesha emergency generator set has a four-stroke, lean-burn, natural gas-fired stationary reciprocating internal combustion engine. The proposed emergency generator will be installed to meet site-wide emergency electrical demands as a result of the AB Project and will be operated only during normal testing and maintenance, and emergency situations. The engine will meet the definition of "emergency engine" per 310 CMR 7.00 Definitions and will be operated under the ERP Certification requirements of 310 CMR 7.26(42) and 310 CMR 70.00. Further, the engine will meet the definition of "emergency stationary internal combustion engine" per 40 CFR 60.4248, will comply with the requirements for operating emergency engines in 40 CFR 60.4243(d), and meet the requirements of 40 CFR 63 Subpart ZZZZ by complying with the requirements of 40 CFR 60 Subpart JJJJ.

The new natural gas-fired fuel gas heater and five new natural gas-fired catalytic space heaters are exempt from permitting per 310 CMR 7.02(2)(b)(15), since the rated heat input of each heater is less than 10 MMBtu/hr. The heaters will comply with applicable state requirements. The existing natural gas-fired heaters and boilers at the Weymouth M&R Station have a rated heat input of less than 10 MMBtu/hr and are therefore exempt from permitting per 310 CMR 7.02(2)(b)(15).

The new parts washer will be a remote reservoir cold solvent cleaner for cleaning equipment parts used at the Site. Potential emissions from the parts washer are conservatively estimated based on a make-up solvent rate of 120 gallons per year and a VOC content of 100 percent by weight. Based on these conservative estimates, potential emissions from operation of the parts washer are less than one tpy for any pollutant. The parts washer is exempt from permitting per 310 CMR 7.03(8) and will be operated in accordance with the requirements of 310 CMR 7.18(8)(a).

The new separator vessels and storage tanks proposed to be installed at the Weymouth Compressor Station are exempt from permitting per 310 CMR 7.02(2)(b)(7) since individually the potential emissions from each of these units are less than one tpy for any pollutant.

The fugitive emissions from truck loading are exempt from permitting since potential emissions from this activity are less than one tpy for any air pollutant.

2.4. ANALYSIS OF THE USE OF ELECTRIC-MOTOR DRIVEN COMPRESSORS

Algonquin is including this additional information on the use of electric motors to drive the compressors as an alternative to using natural-gas turbines to drive the compressor units. There are a number of compelling process and business reasons why Algonquin selected natural gas-fired combustion turbines for the Project. As detailed in Resource Report 10 (RR10) that was submitted to the FERC in connection with the AB Project (Docket No. CP16-9-000), and evaluated in the EA that was issued by the FERC staff on May 2, 2016, Algonquin considered the feasibility of installing electric-driven compressor units for the AB Project at the Weymouth Compressor Station. In this consideration, Algonquin evaluated a broad scope of factors including proximity to existing electric power sources and whether to upgrade existing electric power sources and/or construct new transmission or service lines and ancillary substation facilities. Algonquin also evaluated the installed and operational costs, including a power company's ability to obtain necessary approvals for the electric transmission facilities prior to the planned in-service date, along with the noise and emission standards applicable to turbine driven compressor units.

The EA noted that the installation of an electric-driven compressor unit would require additional facilities to be constructed such as electric transmission lines and substations, as currently there is not enough electric transmission infrastructure in place to accommodate the additional power supply. The EA further noted that for each station, the construction and operation of electric-driven units would increase the environmental impacts of the Project including an increase in the amount of land disturbed and creating new permanent visual impacts.

The EA also noted the following about the unavailability of backup power for electric-driven compressor units:

> *Back-up generators at gas-fired compressor stations provide the lighting, small motor loads, and the ability to power the 125 hp electric motor to start a gas turbine in the event the turbine is off line when utility power is lost. In contrast, electric-driven compressors are solely dependent on the electric grid for their power source. Emergency generators are not sized to be a primary back-up electrical source for large electric drive motors like the 7,700 hp units that would be installed at the Weymouth and Oxford Compressor Station sites.*

After evaluating these factors in relation to the proposed Weymouth Compressor Station, the EA concluded that use of electric-driven compressor units would not be preferable to or offer a significant environmental advantage over the proposed project facilities (See Section 3.3.2 of the EA). Consequently, electric-driven compressors were not selected in the alternatives analysis provided in RR10 of the Atlantic Bridge Project Certificate Application, has not been included in the BACT analysis included in this application, and is not considered further in this application.

This section provides detailed emission calculations for the new Weymouth Compressor Station (new turbine, emergency generator, heaters, parts washer, separator vessels, storage tanks and fugitive components) to be installed at the Site (heaters, boilers, and fugitive components). Attachment G provides the detailed emission calculations for the Site.

3.1. TURBINE EMISSIONS

Potential emissions from the new compressor turbine unit at the proposed Weymouth Compressor Station are estimated for operation during normal steady-state operating conditions, operation during low temperature events, and operation during startup and shutdown events as described in the following sections.

3.1.1. Turbine Normal Steady-State Operation Hourly Emissions

Table 3-1 provides a summary of the uncontrolled emission factors used for each pollutant during normal steady-state operation.

Table 3-1. New Turbine Pre-Control Emission Factors – Normal Operations

Pollutant	Emission Factor [1]	Source
NO_X	9 ppmvd at 15% O_2	Vendor guaranteed emission rate
CO	25 ppmvd at 15% O_2	Vendor guaranteed emission rate
VOC	25 ppmvd TOC at 15% O_2 0.0021 lb/MMBtu (HHV) VOC	TOC: vendor guaranteed emission rate VOC: Table 3.1-2a of AP-42
CH_4	25 ppmvd TOC at 15% O_2 0.0086 lb/MMBtu (HHV) CH_4	TOC: vendor guaranteed emission rate CH_4: Table 3.1-2a of AP-42
$PM_{10}/PM_{2.5}$	0.0066 lb/MMBtu (HHV)	Table 3.1-2a of AP-42
SO_2	14.29 lb/MMscf (HHV)	Table 3.1-2a of AP-42 scaled to 5 gr/100 scf fuel sulfur content
CO_2	53.06 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-1
N_2O	0.0001 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-2
Total HAPs	25 ppmvd TOC at 15% O_2 Multiple HAP factors	TOC: vendor guaranteed emission rate HAPs: Table 3.1-3 of AP-42

[1] The emission factors provided in this table represent uncontrolled emissions at temperatures above 0 °F.

The Taurus 60-7802 turbine is designed to minimize combustion emissions through the use of state-of-the-art SoLoNO$_X$™ dry low emissions technology. For this project, Solar has guaranteed NO_X emissions for the new unit at 9 ppmvd at 15 percent O_2 during steady-state operation at 50-100 percent engine load for all ambient temperatures above 0 °F. The oxidation catalyst vendor has guaranteed a destruction and removal efficiency (DRE) of 95 percent for CO and 50 percent for VOC, resulting in the emission rate provided in this section and Attachment G.

In order to calculate hourly emissions during normal operation, the emission factors provided in the table above are converted to factors in pounds per million standard cubic feet (lb/MMscf) as described in subsequent sections.

3.1.1.1. *Turbine Emission Factors – NO_X, CO and TOC*

NO_X, CO, and Total Organic Compounds (TOC) emitted by the combustion turbine during normal operation are calculated based on the vendor-guaranteed emission rates provided in Table 3-1. Although TOC is not a criteria pollutant, it is used to derive the emission factors for VOC, methane (CH_4 – a greenhouse gas), and HAPs. The turbine vendor provides the emissions and operating data listed below at ambient temperatures of 0 °F, 20 °F, 40 °F, 60 °F, 80 °F and 100 °F:

- Fuel: Lower Heating Value (BTU/scf)
- Turbine Performance: Net Output Power (hp), Heat Input at LHV (MMBtu/hr), Heat Rate at LHV (BTU/hp-hr)
- Exhaust Parameters: Exhaust Temperature (°F), Water Fraction (percent), O_2 Content (percent, dry), Molecular Weight (lb/lb-mol), Flowrate (lb/hr and acfm)
- Guaranteed Emission Rates for NO_X, CO and TOC (ppmvd at 15 percent O_2)

Operating and emissions data at other ambient temperatures are estimated by fitting the vendor-provided data to a curve that best represents the data and interpolating/extrapolating to the desired temperatures. Since the effectiveness of the emissions control inherent in the turbine's combustor design (i.e. SoLoNO$_X$) is only guaranteed at temperatures above 0 °F, the concentration values (parts per million) provided in Table 3-1 do not apply to sub-zero operating conditions. Further, the mass emission rates of NO_X, CO, and TOC at a given load decrease with increasing ambient temperature conditions (i.e., fuel consumption at 100 percent load is highest at lower ambient temperatures). As such, short-term, maximum hourly emission rates are estimated based on operating and emissions data at 0.01 °F to provide the most conservative estimate. Annual emissions estimates are based on the annual average ambient conditions at the proposed site of the Weymouth Compressor Station. As such, for annual emissions estimates, the operating data (turbine performance and exhaust gas parameters) are interpolated to estimate emissions at the average annual ambient temperature at the Site.[4] The emission factor at a given ambient temperature is calculated as illustrated in Equation 3-1 through Equation 3-3:

Equation 3-1: $$\boldsymbol{NO_x, CO, TOC\ EF\ (ppmw) = ppmvd, 15\%\ O_2 \times nonwater\% \times \frac{20.9-(\ vol\%\ O_2,dry \times 100)}{5.9} = ppmw}$$

Equation 3-2: $$NO_x, CO, TOC\ hourly\ emissions\ \left(\frac{lb}{hr}\right) @T = \frac{ppmw}{1{,}000{,}000} \times \left(\frac{lb\ exhaust}{hr}\right)_T \times \frac{\frac{lb\ pollutant}{lb\ mol}}{\left(\frac{lb\ exhaust}{lb\ mol}\right)_T} = \left(\frac{lb\ pollutant}{hr}\right)_T$$

Equation 3-3: $$NO_x, CO, TOC\ EF\ @\ T = \left(\frac{lb}{hr}\right)_T \times \frac{1{,}000{,}000\frac{scf}{MMscf}}{\left[\frac{scf\ fuel}{hr}\right]_T} = \left(\frac{lb}{MMscf}\right)_T$$

Where: *T = ambient temperature*[5]

---

[4] A weighted daily average ambient temperature is used in estimating emissions for the Weymouth Compressor Station and is based on meteorological information in U.S. EPA's TANKS 4.09d database. To determine ambient temperatures, the three meteorological stations in closest proximity to the station were reviewed, and the station with the lowest ambient temperatures was conservatively selected.

[5] Maximum hourly emissions are estimated at T = 0.01°F.

3.1.1.2. Turbine Emission Factors – VOC, CH_4, and HAPs

VOC, CH_4, and HAPs emitted by the combustion turbine are calculated using the vendor-guaranteed TOC emission rate and AP-42 emission factors, as VOC, CH_4, and HAPs are constituents of TOC. The TOC emission factor in terms of lb/MMscf at a given ambient temperature is calculated as outlined above in Section 3.1.1.1.

Standard emission factors for VOC, CH_4, HAPs, and TOC from stationary gas turbines are provided in Chapter 3.1 of EPA's Compilation of Air Pollutant Emission Factors (AP-42). Table 3.1-2a of AP-42 (version dated April 2000) provides emission factors of 0.0023 lb VOC per MMBtu, 0.0086 lb CH_4 per MMBtu, and 0.011 lb TOC per MMBtu from natural gas-fired turbines. Table 3.1-3 of AP-42 (version dated April 2000) provides emission factors for HAPs emitted from natural gas-fired turbines. These HAPs include:

- 1,3-Butadiene
- Acetaldehyde
- Acrolein
- Benzene
- Ethylbenzene
- Formaldehyde
- Naphthalene
- Polycyclic aromatic hydrocarbons (PAH)
- Propylene oxide
- Toluene
- Xylenes

A total HAP emission factor is calculated as the sum of all individual HAP emission factors.

Ratios of VOC, CH_4, and HAPs to TOC from the AP-42 factors are applied to the TOC factor derived from vendor information to obtain emission factors for VOC, CH_4, and HAPs. For normal operation, the uncontrolled VOC, CH_4, and HAP factors are derived as follows:

Equation 3-4: $$VOC, CH_4, HAP\ EF = \frac{lb\ TOC}{MMscf} \times \frac{\left(\frac{lb\ pollutant}{MMBtu} \times 1{,}020\ \frac{MMBtu}{MMscf}\right)}{\left(0.011 \frac{lb\ TOC}{MMBtu} \times 1{,}020\ \frac{MMBtu}{MMscf}\right)} = \frac{lb}{MMscf}$$

3.1.1.3. Turbine Emission Factors – PM_{10}, $PM_{2.5}$, and SO_2

As indicated in Equation 3-5, particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), and sulfur dioxide (SO_2) emitted by the combustion turbine during normal operation are calculated based on the emission factors listed in Table 3.1-2a of AP-42 (version dated April 2000) for stationary gas turbines. The SO_2 emission factor is calculated using AP-42 based on a fuel sulfur content of 5 grains per 100 scf. It is conservatively assumed that all particulate emitted from natural gas combustion is less than 2.5 microns in diameter, so the emission rates for PM_{10} and $PM_{2.5}$ are assumed equal to the total PM emission rate. The AP-42 emission factors are converted to lb/MMscf as follows:

Equation 3-5: $$PM_{10}, PM_{2.5}\ or\ SO_2\ EF = \frac{lb}{MMBtu} \times 1{,}020\ \frac{MMBtu}{MMscf} = \frac{lb}{MMscf}$$

3.1.1.4. Turbine Emission Factors – CO_2, N_2O and CO_2e

Emission factors for carbon dioxide (CO_2) and nitrous oxides (N_2O) emitted by the combustion of natural gas are calculated based on the HHV and the emission factors provided for pipeline natural gas combustion in 40 CFR 98, Subpart C, Tables C-1 and C-2, as follows:

Equation 3-6: $$CO_2\ EF = 53.06 \frac{kg}{MMBtu} \times 2.2046 \frac{lb}{kg} \times 1{,}028 \frac{Btu}{scf} = 120{,}161 \frac{lb\ CO_2}{MMscf}$$

Equation 3-7: $$N_2O\ EF = 0.0001 \frac{kg}{MMBtu} \times 2.2046 \frac{lb}{kg} \times 1{,}028 \frac{Btu}{scf} = 0.23 \frac{lb\ N_2O}{MMscf}$$

Total greenhouse gas (GHG) emissions in terms of CO_2 equivalents (CO_2e) are equal to the sum of all individual GHGs emitted by the turbine, accounting for the respective global warming potential of each GHG. The global warming potentials (GWPs) used to calculate CO_2e emissions for each pollutant emitted by the Project are contained in Table 3-2.

Table 3-2. Applicable Global Warming Potentials

Pollutant [1]	GWP [2]
CO_2	1
CH_4	25
N_2O	298

[1] Only those GHGs for which quantifiable emissions increases are expected due to this project are listed.

[2] GWPs are based on a 100-year time horizon, as identified in Table A-1 to 40 CFR Part 98, Subpart A as amended on November 29, 2013 to incorporate revised GWPs as published in the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report (AR4).

As such, the CO_2e factor is derived as follows:

Equation 3-8: $$CO_2e\ EF = \left(\frac{lb\ CO_2}{MMscf} \times 1\ GWP\right) + \left(\frac{lb\ CH_4}{MMscf} \times 25\ GWP\right) + \left(\frac{lb\ N_2O}{MMscf} \times 298\ GWP\right) = \frac{lb\ CO_2}{MMscf}$$

3.1.2. Turbine Low Temperature Operation Hourly Emissions

At low ambient temperatures (i.e., temperatures below 0 °F), lb/hr emissions of NO_X, CO, and VOC increase. Low temperature hourly emissions were estimated using the vendor estimated emission rates at sub-zero temperatures (provided in Table 3-3), and following the calculation methodology outlined in the previous section for normal steady-state operation.

Table 3-3. New Turbine Emission Factors – Low Temperature Operation

Pollutant	Emission Factor (0 °F ≥ Temp ≥ - 20 °F)	Emission Factor (Temp ≤ - 20 °F)	Source
NO_X	42 ppmvd at 15% O_2	120 ppmvd at 15% O_2	Vendor provided emission rate
CO	100 ppmvd at 15% O_2	150 ppmvd at 15% O_2	Vendor provided emission rate
TOC	50 ppmvd at 15% O_2	75 ppmvd at 15% O_2	Vendor provided emission rate

The same emission rates that are used for normal operation for PM_{10}, $PM_{2.5}$, SO_2, CO_2, and N_2O are used for low temperature operation. However, it should be noted that the maximum hourly fuel consumption increases during low temperature operation, so hourly emissions during low temperature operation are higher than hourly emissions during normal operation, even for those pollutants for which the emissions on a lb/MMscf basis are not impacted by low temperature operation.

3.1.3. Turbine Startup and Shutdown Operation Hourly Emissions

Emissions during startups and shutdowns are calculated based on vendor-specified transient operation profiles which are used to determine the maximum pound of pollutant per startup or shutdown event as described in further detail in the following sections.

3.1.3.1. Turbine Startup Operation

The startup process for the turbine is estimated to take approximately nine minutes from the initiation of startup to normal operation (startup sequence ends at approximately 50 percent load for most Solar turbines). This includes three minutes of ignition-idle operation and six minutes of loading/thermal stabilization operation.

Table 3-4 provides a summary of the emission factors used for each pollutant during the ignition-idle and loading/thermal stabilization phases of each startup event. It is assumed that the oxidation catalyst will not yet have a measurable destruction or removal efficiency (DRE) during startup, as it is designed to meet control specifications only during normal operation.

Table 3-4. New Turbine Emission Factors – Startup Operation

Pollutant	Ignition-Idle Phase Emission Factor from Source [1]	Loading/Thermal Stabilization Phase Emission Factor from Source [1]	Source
NO_X	50 ppmvd at 15% O_2	60 ppmvd at 15% O_2	Vendor specified emission rate
CO	10,000 ppmvd at 15% O_2	9,000 ppmvd at 15% O_2	Vendor specified emission rate
VOC	7,700 ppmvd TOC at 15% O_2 0.0021 lb/MMBtu (HHV) VOC	4,460 ppmvd TOC at 15% O_2 0.0021 lb/MMBtu (HHV) VOC	TOC: vendor specified emission rate VOC: Table 3.1-2a of AP-42
CH_4	7,700 ppmvd TOC at 15% O_2 0.0086 lb/MMBtu (HHV) CH_4	4,460 ppmvd TOC at 15% O_2 0.0086 lb/MMBtu (HHV) CH_4	TOC: vendor specified emission rate CH_4: Table 3.1-2a of AP-42
$PM_{10}/PM_{2.5}$	Same as normal operation		
SO_2	Same as normal operation		
CO_2	Same as normal operation		
N_2O	Same as normal operation		
Total HAPs	7,700 ppmvd TOC at 15% O_2 Multiple HAP factors	4,460 ppmvd TOC at 15% O_2 Multiple HAP factors	TOC: vendor specified emission rate HAPs: Table 3.1-3 of AP-42

[1] The emission factors provided in this table represent uncontrolled emissions. The new turbine will be equipped with an oxidation catalyst, however it is assumed that the catalyst is not fully operational during startups.

All pollutants emitted by the combustion turbine during startup events are calculated based on the same methodology that is used to calculate emissions during normal operation. However, rather than calculate lb/MMscf emission factors, pounds per startup event (lb/event) are calculated for each pollutant based on the fuel consumed during the three-minute ignition-idle phase and during the six-minute loading/thermal stabilization phase as follows:

Equation 3-9: $$EF_x \ during \ SU \ event = \frac{lb \ Pollutant \ x}{MMBtu} \times 1{,}020 \ \frac{MMBtu}{MMscf} \times \frac{scf \ fuel}{event} \times \frac{MMscf}{1{,}000{,}000 \ scf} = \frac{lb \ Pollutant \ x}{event}$$

3.1.3.2. Turbine Shutdown Operation

The shutdown process for the turbine is estimated to take approximately 8.5 minutes from normal operation to shut down for a Taurus 60-7802. The shutdown event consists of loading/thermal stabilization operation.

Table 3-5 provides a summary of the pre-control emission factors used for each pollutant during each shutdown event. It is assumed that the oxidation catalyst will be operational during shutdown. The calculation for shutdowns is identical to that for startups as shown in Equation 3-9 above, except that the oxidation catalyst DRE is accounted for in calculating potential emissions.

Table 3-5. New Turbine Pre-Control Emission Factors – Shutdown Operation

Pollutant	Loading/Thermal Stabilization Phase Emission Factor from Source [1]	Source
NO_X	60 ppmvd at 15% O_2	Vendor specified emission rate
CO	9,000 ppmvd at 15% O_2	Vendor specified emission rate
VOC	4,460 ppmvd TOC at 15% O_2 0.0021 lb/MMBtu (HHV) VOC	TOC: vendor specified emission rate VOC: Table 3.1-2a of AP-42
CH_4	4,460 ppmvd TOC at 15% O_2 0.0086 lb/MMBtu (HHV) CH_4	TOC: vendor specified emission rate CH_4: Table 3.1-2a of AP-42
$PM_{10}/PM_{2.5}$	Same as normal operation	
SO_2	Same as normal operation	
CO_2	Same as normal operation	
N_2O	Same as normal operation	
Total HAPs	4,460 ppmvd TOC at 15% O_2 Multiple HAP factors	TOC: vendor specified emission rate HAPs: Table 3.1-3 of AP-42

[1] The emission factors provided in this table represent uncontrolled emissions. The new turbine will be equipped with an oxidation catalyst, but the control from the catalyst is not accounted for in the factors above.

3.1.4. Turbine Transient Operation Hourly Emissions

There are times when the turbine could operate outside the conditions upon which Solar has based its SoLoNO$_X$™ combustor emissions guarantee: during startup; during shutdown; during low ambient temperature operation (i.e., below 0 °F); and during transient events[6]. Solar programs the turbine monitoring system to measure numerous operating parameters in order to verify the turbine is achieving the conditions upon which the emissions guarantee is established. If the turbine monitoring system detects that these conditions are not achieved, the mode of the SoLoNO$_X$™ combustor will indicate "inactive".

Transient events are infrequent periods of short duration when the turbine is not achieving the emissions guarantee provided by the vendor. These periods occur as a result of the turbine losing combustion stability in the lean premix mode. In order to stabilize combustion, the turbine control system increases the pilot fuel rate to the combustion chamber. This results in higher emissions until stable lean premix mode is achieved again. Manufacturer guidance is that transient events result in emissions somewhere between those guaranteed for SoLoNO$_X$™ mode and the worst-case emission rates provided for full load operation at ambient conditions less than or equal to -20 °F. It should be noted that while the SoLoNO$_X$™ combustor technology may not be fully effective during transient events, it is assumed the oxidation catalyst is operational and controls CO (95%) and VOC (50%).

It is also important to note that the proposed emission limits are reported on a pound per hour (lb/hr) basis per the request of the MassDEP. However, actual conditions would likely not result in transient events occurring for more than a few minutes. Transient events will be limited to 25 hours per month and 50 hours per consecutive 12-month period. This limit does not include startup, shutdown, or low temperature events, which are permitted separately.

[6] Transient events are periods of time when the turbine is operating outside of steady state or at less than 50% load, excluding startup, shutdown, or low temperature events.

3.1.5. Turbine Annual Potential Emissions

The emission factors described in the previous sections are multiplied by the following activity data to estimate annual potential emissions:

- **Normal Steady State Operation:** Annual fuel consumption as estimated from vendor-provided turbine parameters at the annual average ambient temperature for the proposed site of the Weymouth Compressor Station. Annual potential to emit (PTE) estimates assume 100 percent utilization (8,760 hours per year). CO, VOC, and HAP PTE estimates take the control efficiency of the proposed oxidation catalyst into account. Further, since an oxidation catalyst provides more complete conversion of CO to CO_2 (also a regulated pollutant), the controlled portion of the CO emissions is added back to the CO_2 emissions rate.
- **Low Temperature Operation:** Fuel consumption during low temperature operation as estimated by extrapolating vendor-provided turbine parameters to an ambient temperature of -20 ^oF. It is conservatively assumed that low temperature operation between -20 ^oF and 0 ^oF will account for a total of 12 hours per year. Due to the fact that the meteorological data indicates that there are expected to be no hours at -20 ^oF or below, it is assumed that low temperature operation less than or equal to -20 ^oF will account for a total of zero hours per year.[7]
- **Startup/Shutdown Operations:** The number of startup and shutdown events is conservatively estimated at 416 startup events and 416 shutdown events per year for the turbine. No credit for control by the oxidation catalyst is accounted for in the estimation of startup emissions. However, it is assumed that the oxidation catalyst will be operational during shutdown.
- **Transient Operations:** Transient emissions will count against total annual emissions as presented in Table 3-13.

For some pollutants, emission rates from the combustion turbine are higher during normal steady-state operation than they are during low temperature operation or startup and shutdown. However, for other pollutants, emission rates may be higher during low temperature operation or startup and shutdown than during normal operation. As such, maximum annual emissions for the turbine are the maximum of potential combinations of normal, startup, shutdown, and low temperature operation as summarized in Equations 3-10 through 3-13 below.

Equation 3-10: $$Normal\,\frac{ton}{yr} = Average\,\frac{lb}{hr} \times \frac{8{,}760\ hr}{yr} \times \frac{ton}{2{,}000\ lb}$$

Equation 3-11: $$Normal\ with\ Startup\ (SU)\ and\ Shutdown(SD)\left(\frac{ton}{yr}\right) = startup\,\frac{ton}{yr} + \ shutdown\,\frac{ton}{yr} + \left(normal\,\frac{ton}{yr} \times (1 - \frac{startup\ hrs+shutdown\ hrs}{8760})\right)$$

Equation 3-12: $$Normal\ with\ Low\ Temp\ (LT)\left(\frac{ton}{yr}\right) = low\ temp\,\frac{ton}{yr} + \left(normal\ \frac{ton}{yr} \times (1 - \frac{low\ temp\ hrs}{8760})\right)$$

[7] The 12 hours per year of low temperature operation is conservatively determined based on data extracted from USDOE-NREL's National Solar Radiation Database 1991-2010. The number of low temperature hours is determined based on data from the three stations in closest proximity to the station. Low temperature hours as well as distance to station are considered in determining the number of low temperature hours at the station for emission calculation purposes.

Equation 3-13: $Normal\ with\ SU, SD, and\ Low\ Temp\ (LT) \left(\frac{ton}{yr}\right) = startup\ \frac{ton}{yr} + shutdown\ \frac{ton}{yr} + low\ temp \frac{ton}{yr} + \left(normal\ \frac{ton}{yr} \times (1 - \frac{startup\ hrs + shutdown\ hrs + low\ temp\ hrs}{8760})\right)$

Equation 3-14: $Annual\ PTE\ \left(\frac{ton}{yr}\right)_{Pollutant\ i} = \text{MAX}\left[Normal \left(\frac{ton}{yr}\right), Normal\ with\ SU, SD\ \left(\frac{ton}{yr}\right)\ , Normal\ with\ LT\ \left(\frac{ton}{yr}\right), Normal\ with\ SU, SD, LT\ \left(\frac{ton}{yr}\right)\right]_i$

3.1.6. Short-Term Emission Limits

Algonquin requests short-term emission limits for the new Solar Taurus 60-7802 natural gas-fired turbine operation for the following alternate operating scenarios: (1) startup and shutdown; (2) low temperature conditions between 0 °F and -20 °F; (3) low temperature conditions below -20 °F; and (4) transient events. As such, the short term emission rates for the new turbine operation for alternate operating scenarios (1) through (3) are provided below in Tables 3-6 through 3-8. Proposed short-term emissions limits for NO_X, CO and VOC during a transient event are conservatively assumed to be equivalent to the emission rates provided in Table 3-7 for full load operation at ambient temperatures less than or equal to -20 °F, which are the worst-case estimate provided by the vendor for transient operation. Please note that the emission rates for the new turbine operating under normal conditions are provided in the CPA-FUEL Form.

- Pollutant emissions for the turbine operating at ambient temperatures between -20°F and 0°F are presented in Table 3-6 below. The emission rates are based on vendor full load operating data at an ambient temperature of -20˚F; vendor guarantee for NO_X, CO, and TOC emissions; AP-42; and use of an oxidation catalyst as described in Section 3.1.2.

Table 3-6. Turbine Operating Emission Rates for Ambient Temperatures between -20°F and 0°F [8]

Pollutant	Low Ambient Temperature Emissions (lb/hr)
PM	0.49
PM_{10}	0.49
$PM_{2.5}$	0.49
SO_2	1.05
NO_X	11.36
VOC [9]	0.52
CO	0.82

- Pollutant emissions for the turbine operating at temperatures below -20°F are presented in Table 3-7. The emission rates are based on vendor full load operating data at an ambient temperature of -20˚F; vendor

[8] The emission rates can also be found in Table B-1Aj in Attachment G to this report.
[9] VOC emission rate is based on vendor guaranteed TOC emissions, and AP-42 emission factors. Ratios of VOC to TOC from the AP-42 factors are applied to the TOC factor derived from vendor information to obtain emission factors for VOC as described in Section 3.1.1.

guarantee for NO_X, CO, and TOC emissions; AP-42; and use of an oxidation catalyst as described in Section 3.1.2.

Table 3-7. Turbine Operating Emission Rates for Ambient Temperatures below -20°F [8]

Pollutant	Extreme Low Ambient Temperature Emissions (lb/hr)
PM	0.49
PM_{10}	0.49
$PM_{2.5}$	0.49
SO_2	1.05
NO_X	32.46
VOC[9]	0.77
CO	1.24

- Pollutant emissions for turbine operation during startup and shutdown scenarios are presented in Table 3-8. The emission rates are based on vendor guarantee for NO_X, CO, and TOC at an ambient temperature of 0.01˚F; AP-42; and use of an oxidation catalyst only for shutdown emissions as described in Section 3.1.3. No control is assumed for the oxidation catalyst during startup as the catalyst will not reach its effective operating temperature until the end of the startup period.

Table 3-8. Turbine Emission Rates for Startup and Shutdown [10]

Pollutant	Startup Emissions (lb/event)	Shutdown Emissions (lb/event)
NO_X	0.80	0.93
CO	77.24	4.23 [11]
VOC [9]	5.40	2.62 [11]

3.1.7. Proposed Compliance Demonstration

As indicated in Table 3-1, the maximum emission rate for the new turbine during normal operation will be 9 ppmvd of NO_X at 15 percent O_2 on a 3-hour average. Since this is a new technology and the resulting NO_X emissions are dependent on site-specific factors, Algonquin and Solar are requesting an extended shakedown period to fully evaluate and tune the new turbine installation to achieve the very low NO_X BACT emission rate. Based on information from the vendor, Algonquin expects a 6-month shakedown period before the 9 ppmvd technology will be installed and fully operational on the turbine.

[10] Please note that the estimated potential hourly emission rates for startup and shutdown are included in the detailed emissions calculations for the Site in Attachment G to this report. The pounds per event (lb/event) emission rates for startup and shutdown (without the use of oxidation catalyst) are provided in Table B-1Af and Table B-1Ag respectively in Attachment G to this report.

[11] The shutdown emission limit takes into account an oxidation catalyst control efficiency of 95 percent for CO and 50 percent for VOC.

Algonquin proposes to demonstrate compliance with the 9 ppmvd NO_X limit for the new turbine via initial and subsequent emissions testing according to the requirements of 40 CFR Part 60 Subpart KKKK, as detailed in Section 4.3.1 below. Algonquin also proposes to continuously monitor natural gas flow to the new turbine to ensure compliance with the annual potential NO_X emission rate shown in Table 3-13 on a rolling 12-month basis. Prior to the initial compliance demonstration (i.e., during the shakedown period), Algonquin will conservatively estimate emissions from the new turbine based on an emission factor of 15 ppmvd NO_X.

3.2. EMERGENCY GENERATOR EMISSIONS

Algonquin is proposing to install a new Waukesha 585 bhp, four stroke lean burn natural gas-fired emergency generator. The emergency generator will be limited to 300 hours/year by the ERP Certification requirements of 310 CMR 7.26(42) and 310 CMR 70.00. Table 3-9 provides information on the emission factors used to calculate emissions from the emergency generator.

Table 3-9. Waukesha Emergency Generator Emission Factors

Pollutant	Emission Factor from Source	Source
NO_X	2.0 g/bhp-hr	Vendor data.
CO	1.3 g/bhp-hr	Vendor data.
Formaldehyde	0.19 g/bhp-hr	Vendor data.
VOC	Formaldehyde: 0.19 g/bhp-hr VOC: 0.119 lb/MMBtu (HHV)	Formaldehyde: Vendor Data VOC: Table 3.2-2 of AP-42
CH_4	Formaldehyde: 0.19 g/bhp-hr CH_4: 1.25 lb/MMBtu (HHV)	Formaldehyde: Vendor Data CH_4: Table 3.2-2 of AP-42
$PM_{10}/PM_{2.5}$	0.00999 lb/MMBtu (HHV)	Table 3.2-2 of AP-42
SO_2	14.29 lb/MMscf	Table 3.2-2 of AP-42 scaled to 5 gr/100 scf fuel sulfur content
CO_2	53.06 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-1
N_2O	0.0001 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-2
Total HAPs	Formaldehyde: 0.19 g/bhp-hr Multiple HAP factors	Formaldehyde: Vendor Data Multiple HAPs: Table 3.2-2 of AP-42

In order to calculate hourly emissions, the emission factors provided in Table 3-9 are converted to factors in lb/MMscf. These converted factors are multiplied by the generator's hourly fuel consumption in scf/hr to obtain hourly emissions. The following sections summarize the methods used to obtain lb/MMscf emission factors for each pollutant emitted from the new emergency generator.

3.2.1. Emergency Generator Emission Factors - NO_X, CO, and Formaldehyde

NO_X, CO, and Formaldehyde emitted by the emergency generator are calculated based on vendor guaranteed emission factors. Vendor-specified power output and fuel consumption for the engine are used to convert the g/bhp-hr factors. NO_X, CO, and Formaldehyde factors are derived as follows:

Equation 3-15:
$$NO_x, CO, Formaldehyde\ EF = \frac{g}{bhp-hr} \times \frac{lb}{453.6\ g} \times bhp \times \frac{hr}{scf\ fuel} \times \frac{1{,}000{,}000\ scf}{MMscf} = \frac{lb}{MMscf}$$

3.2.2. Emergency Generator Emission Factors - VOC, CH_4 and HAPs

VOC, CH_4 and HAP emissions are calculated using the Formaldehyde emission rate and AP-42 emission factors. Standard emission factors for CH_4, Formaldehyde, and HAPs from natural gas-fired engines are provided in Chapter 3.2 of AP-42. Table 3.2-2 (version dated July 2000) provides emission factors for CH_4, Formaldehyde, and HAPs from four-stroke, lean-burn, natural gas-fired engines. A VOC factor is calculated based as the sum of the factors for all trace organic compounds listed in Table 3.2-2 which are VOCs.

Using the similar ratio method used to calculate CH_4 and HAPs emitted from the turbine (detailed in Section 3.1.1.2), VOC, CH_4 and HAPs emitted from engines are scaled based on the Formaldehyde emission rate from vendor data.

Equation 3-16: $$VOC, CH_4, HAP\ EF = \left[\frac{EF_{Formaldehyde\ Vendor}}{EF_{FormaldehydeAP42}}\right] \times (EF_{VOCAP42}) = lb/mmcf$$

3.2.3. Emergency Generator Emission Factors - PM_{10}, $PM_{2.5}$, and SO_2

PM_{10} and $PM_{2.5}$ emitted by the emergency generator are calculated based on the emission factors listed in Table 3.2-2 of AP-42 (version dated July 2000) for natural gas-fired engines. PM_{10} and $PM_{2.5}$ emission factors are calculated as the sum of the filterable and condensable PM emission factors. The SO_2 emission factor from Table 3.2-2 of AP-42 is scaled from a fuel sulfur content of 2,000 grains per MMscf to a fuel sulfur content of 5 grains per 100 scf.

3.2.4. Emergency Generator Emission Factors - CO_2, N_2O, and CO_2e

CO_2 and N_2O emitted by the emergency generator are calculated based on the emission factors listed in 40 CFR 98, Subpart C, Tables C-1 and C-2. Equation 3-6 and Equation 3-7 show how factors in lb/MMscf are derived for these pollutants. GHGs emitted from the engine include CO_2, CH_4, and N_2O. CO_2e emissions are calculated using the GWPs provided in Table 3-2.

3.3. NATURAL GAS HEATER EMISSIONS

Algonquin is proposing to install a new natural gas-fired fuel gas heater with a heat input of 0.23 MMBtu/hr at the Weymouth Compressor Station. In addition, there are two existing natural gas-fired heaters at the Weymouth M&R Station. Table 3-10 provides information on the emission factors used to calculate emissions from the new and existing heaters.

Table 3-10. Process Heater Emission Factors [1]

Pollutant	Emission Factor from Source	Source
NO_X	80 ppmvd at 3% O_2	Vendor specified emission rate
CO	200 ppmvd at 3% O_2	Vendor specified emission rate
TOC	140 ppmvd at 3% O_2	Vendor specified emission rate
VOC	140 ppmvd TOC at 3% O_2 8.18 lb/MMscf VOC	TOC: vendor specified emission rate Table 1.4-3 of AP-42
CH_4	140 ppmvd TOC at 3% O_2 2.30 lb/MMscf CH_4	TOC: vendor specified emission rate Table 1.4-2 of AP-42
$PM_{10}/PM_{2.5}$	7.60 lb/MMscf	Table 1.4-2 of AP-42
SO_2	14.29 lb/MMscf	Table 1.4-2 of AP-42 scaled to 5 gr/100 scf fuel sulfur content
CO_2	53.06kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-1
N_2O	0.0001 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-2
Total HAPs	Multiple HAP factors	Table 1.4-3 of AP-42

[1] New heaters at compressor station and existing heaters at M&R station.

In order to calculate hourly emissions, the emission factors provided in Table3-7 are converted to factors in lb/MMscf. These converted factors are multiplied by the heater's hourly fuel consumption in scf/hr to obtain hourly emissions. Fuel consumption is calculated from the heat output of the heaters assuming a thermal efficiency of 65 percent for the new proposed heater and 75 percent for the existing heaters and a natural gas heating value of 1,020 Btu/scf. Annual potential emissions are calculated based on average hourly fuel consumption. Maximum hourly potential emissions are calculated based on maximum hourly fuel consumption, assuming an overload capability of 105 percent. The following sections summarize the methods used to obtain lb/MMscf emission factors for each pollutant emitted from the new and existing heaters.

3.3.1. Process Heater Emission Factors – NO_X, CO, and TOC

NO_X, CO, and TOC emitted by the heaters are calculated based on vendor-specified emission rates and vendor-specified fuel consumption for the heaters. NO_X, CO, and TOC factors are derived as follows:

Equation 3-17:

$$NO_x, CO, TOC\ EF = ppmvd, 3\%\ O_2 \times \frac{lb/MMBtu}{ppmvd, 3\%\ O_2} \times 1{,}020 \frac{MMBtu}{MMscf} = \frac{lb}{MMscf}$$

Where: 1 ppmvd, 3% O_2 = 829 NO_2 lb/MMbtu,
= 1,360 CO lb/MMbtu and
= 2380 TOC (as CH_4) lb/MMbtu

3.3.2. Heater Emission Factors – VOC, CH_4, and HAPs

VOC, CH_4, and HAP emissions are calculated using the vendor-specified TOC emission rate and AP-42 emission factors. Standard emission factors for TOC, VOC, CH_4, and HAPs from natural gas-fired heaters are provided in Chapter 1.4 of AP-42. Table 1.4-2 (version dated July 1998) provides a CH_4 emission factor for natural gas-fired external combustion sources. The TOC and VOC factors used in the calculations differ slightly from the factors provided in Table 1.4-2. TOC and VOC factors are calculated as the sum of the factors for all speciated organic compounds listed in Table 1.4-3 which are TOCs and VOCs, respectively. Table 1.4-3 of AP-42 (version dated July 2000) provides emission factors for the HAPs emitted from natural gas-fired external combustion units.

VOC, CH_4, and HAP emissions from the heaters are calculated using the same ratio method used to calculate VOC, CH_4, and HAPs emitted from the turbine (detailed in Section 3.1.1.2) based on the vendor-specified TOC emission rate.

3.3.3. Heater Emission Factors - PM_{10}, $PM_{2.5}$, and SO_2

PM_{10} and $PM_{2.5}$ emitted by the heaters are calculated based on the emission factors listed in Table 1.4-2 of AP-42 (version dated July 1998) for natural gas-fired external combustion sources. The total PM emission factor of 7.6 lb/MMscf, which includes filterable and condensable particulate, is used. It is assumed that all particulate emitted from natural gas combustion is less than 2.5 microns in diameters, so that PM equals PM10 and PM2.5. The SO_2 emission factor of 0.6 lb/MMscf from Table 1.4-2 of AP-42 is scaled from a fuel sulfur content of 2,000 grains per MMscf to a fuel sulfur content of 5 grains per 100 scf.

3.3.4. Heater Emission Factors - CO_2, N_2O, and CO_2e

CO_2 and N_2O emitted by the heater are calculated based on the emission factors listed in 40 CFR 98, Subpart C, Tables C-1 and C-2. Equation 3-6 and Equation 3-6 show how factors in lb/MMscf are derived for these pollutants. GHGs emitted from the heater include CO_2, CH_4, and N_2O. CO_2e emissions are calculated using the GWPs provided in Table 3-2.

3.4. CATALYTIC SPACE HEATER EMISSIONS

Algonquin is proposing to install five new natural gas-fired catalytic space heaters with a heat input of 0.072 MMBtu/hr each at the Weymouth Compressor Station. Table 3-11 provides information on the emission factors used to calculate emissions from the five catalytic space heaters.

Table 3-11. Catalytic Space Heater Emission Factors

Pollutant	Emission Factor from Source	Source
NO_X	94 lb/MMscf	Table 1.4-1 of AP-42
CO	40 lb/MMscf	Table 1.4-1 of AP-42
TOC	Multiple factors for speciated TOC compounds	Table 1.4-3 of AP-42
VOC	Multiple factors for speciated VOC compounds	Table 1.4-3 of AP-42
CH_4	2.30 lb/MMscf	Table 1.4-2 of AP-42
$PM_{10}/PM_{2.5}$	7.60 lb/MMscf	Table 1.4-2 of AP-42
SO_2	14.29 lb/MMscf	Table 1.4-2 of AP-42 scaled to 5 gr/100 scf fuel sulfur content
CO_2	53.06 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-1
N_2O	0.0001 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-2
Total HAPs	Multiple HAP factors	Table 1.4-3 of AP-42

The emission factors provided in Table 3-11 are first converted to factors in lb/MMscf and then multiplied by the space heater's hourly fuel consumption in standard cubic feet per hour (scf/hr) to obtain hourly emissions. Fuel consumption is calculated from the heat output of the space heater assuming a thermal efficiency of 80 percent and a natural gas heating value of 1,020 Btu/scf. Annual potential emissions are calculated based on the average hourly fuel consumption rate and 8,760 hours per year. Maximum hourly potential emissions are calculated based on maximum hourly fuel consumption, assuming an overload capability of 105 percent. The following sections summarize the methods used to obtain lb/MMscf emission factors for each pollutant emitted from the new space heaters.

3.4.1. Space Heater Emission Factors – NO_X and CO

NO_X and CO emitted by the space heaters are calculated based on emission factors provided directly in Table 1.4-1 of AP-42 (version dated July 1998) for residential furnaces with heat input ratings of less than 0.3 MMBtu/hr with no control.

3.4.2. Space Heater Emission Factors – TOC, VOC, and HAPs

TOC, VOC, and HAP emissions are calculated using the AP-42 emission factors. Standard emission factors for TOC and VOC from natural gas-fired external combustion sources are provided in Chapter 1.4 of AP-42. The TOC and VOC factors used in the calculations differ slightly from the factors provided in Table 1.4-2. TOC and VOC factors are calculated as the sum of the factors for all speciated organic compounds listed in Table 1.4-3 which are TOCs and VOCs, respectively.[12] Table 1.4-3 of AP-42 (version dated July 1998) provides emission factors for the HAPs emitted from natural gas-fired external combustion units.

3.4.3. Space Heater Emission Factors – PM_{10}, $PM_{2.5}$, SO_2, and CH_4

PM_{10} and $PM_{2.5}$ emitted by the space heaters are calculated based on the emission factors listed in Table 1.4-2 of AP-42 (version dated July 1998) for natural gas-fired external combustion sources. The total PM emission factor of 7.6 lb/MMscf, which includes filterable and condensable particulate, is used. It is assumed that all particulate emitted from natural gas combustion is less than 2.5 microns in diameters, so the emission rates for PM_{10} and $PM_{2.5}$ are assumed equal to the total PM emission rate. The SO_2 emission factor of 0.6 lb/MMscf from Table 1.4-2 of AP-42 is scaled from a fuel sulfur content of 2,000 grains per MMscf to a fuel sulfur content of 5 grains per 100 scf. The CH_4 emission factor of 2.3 lb/MMscf is used directly from Table 1.4-2 of AP-42.

3.4.4. Space Heater Emission Factors – CO_2, N_2O, and CO_2e

CO_2 and N_2O emitted by the space heaters are calculated based on the emission factors listed in 40 CFR 98, Subpart C, Tables C-1 and C-2. Equation 3-6 and Equation 3-7 show how factors in lb/MMscf are derived for these pollutants. GHGs emitted from the heater include CO_2, CH_4, and N_2O. CO_2e emissions are calculated using the GWPs provided in Table 3-2.

[12] For TOC, VOC, CH_4, and CO_2, the most conservative approach in either AP-42 or 40 CFR Part 98 (if applicable) was used to calculate potential emissions.

3.5. NATURAL GAS-FIRED BOILERS

There are three Lochinvar boilers rated at 1.8 MMBtu/hr heat input capacity at the Weymouth M&R Station. Table 3-12 provides information on the emission factors used to calculate emissions from the three existing boilers.

Table 3-12. Boiler Emission Factors

Pollutant	Emission Factor from Source	Source
NO_X	30 ppmvd at 3% O_2	Vendor specified emission rate
CO	84 lb/MMscf	Table 1.4-1 of AP-42
TOC	Multiple factors for speciated TOC compounds	Table 1.4-3 of AP-42
VOC	Multiple factors for speciated VOC compounds	Table 1.4-3 of AP-42
CH_4	2.30 lb/MMscf	Table 1.4-2 of AP-42
PM_{10}/$PM_{2.5}$	7.60 lb/MMscf	Table 1.4-2 of AP-42
SO_2	14.29 lb/MMscf	Table 1.4-2 of AP-42 scaled to 5 gr/100 scf fuel sulfur content
CO_2	53.06 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-1
N_2O	0.0001 kg/MMBtu (HHV)	40 CFR 98, Subpart C, Table C-2
Total HAPs	Multiple HAP factors	Table 1.4-3 of AP-42

The emission factors provided in Table 3-12 are first converted to factors in lb/MMscf and then multiplied by the boiler's hourly fuel consumption in standard cubic feet per hour (scf/hr) to obtain hourly emissions. Fuel consumption is calculated from the heat output of the boiler assuming a thermal efficiency of 84 percent and a natural gas heating value of 1,020 Btu/scf. Annual potential emissions are calculated based on the average hourly fuel consumption rate and 8,760 hours per year. Maximum hourly potential emissions are calculated based on maximum hourly fuel consumption, assuming an overload capability of 105 percent. The following sections summarize the methods used to obtain lb/MMscf emission factors for each pollutant emitted from the existing boilers at the M&R Station.

3.5.1. Boiler Emission Factors – NO_X and CO

NO_X emissions from the boilers are based on vendor-specified emission rates and vendor-specified fuel consumption for the heaters as calculated in Equation 3-17 above. The CO emitted by the boilers is calculated based on emission factors provided directly in Table 1.4-1 of AP-42 (version dated July 1998) for small boilers with heat input ratings of less than 100 MMBtu/hr.

3.5.2. Boiler Emission Factors – Other Pollutants

Emissions for rest of the pollutants, including TOC, VOC, HAPs, PM_{10} and $PM_{2.5}$, SO_2, CH_4, CO_2, N_2O, and CO_2e, are calculated as specified in Section in 3.4 for space heaters.

3.6. PARTS WASHER EMISSIONS

Algonquin is proposing to install a new remote reservoir parts washer. Potential emissions from the parts washer are calculated based on the physical and chemical properties of a worst-case representative solvent used in the parts washer and the maximum throughput of the parts washer. In order to conservatively calculate potential emissions, it is assumed that all volatile organic compounds in the solvent are emitted to the atmosphere and that the VOC content is 100 percent. The maximum throughput of the parts washer will be 120 gallons of solvent per year, based on past experience and the addition of a safety factor. A worst-case specific gravity is assumed based on typical solvents used at other Algonquin sites.

Potential VOC emissions from the parts washer are calculated as follows:

Equation 3-18: $$VOC = 120\frac{gal\ solvent}{year} \times (0.82\ \times 8.34\frac{lb}{gal})\ \times 1\frac{lb\ VOC}{lb\ solvent} = 0.4103\frac{tons\ VOC}{yr}$$

3.7. STORAGE TANKS

Although natural gas in pipelines is considered a dry gas, it is not uncommon for a certain amount of water and hydrocarbons to condense out of the gas stream while in transit. Removing the condensate is a necessary activity to ensure that the natural gas in the pipeline is as pure as possible. Compressor stations typically have equipment to remove liquids from the natural gas in order to protect equipment (e.g., scrubbers, separators, filters, traps, drains, and drip pots). Separator vessels are designed with baffles and demister pads to ensure removal of any liquid entrained in the natural gas prior to atmospheric release. Any liquid that is separated in the vessels is stabilized and then transferred to the condensate storage tank via the pipeline liquids system. Stabilization of condensate is a process utilizing controlled flashing (the partial vapor that occurs when a saturated liquid stream undergoes a reduction in pressure by passing through a throttling valve or other throttling device) to allow it to be stored in atmospheric vessels. At the Weymouth Compressor Station, flashing losses will occur at the separator vessels and include VOCs, GHGs, and HAPs. Total flashing losses are calculated based on a flash gas rate and a representative flash gas density. The flash gas rate is calculated based on a liquids input rate and a flash factor.[13] Emissions of individual VOCs, GHGs, and HAPs are calculated from total flashing losses using a representative pipeline liquids composition. Stabilized condensate has no flashing losses, but has negligible emissions due to breathing and working losses.

Working and breathing losses occur at all tanks at the Weymouth Compressor Station, including separator vessels, the condensate storage tank, the lubricating oil storage tank, and the oily water storage tank. Working and breathing losses include VOCs, GHGs, and HAPs and are calculated with the U.S. EPA's TANKS 4.09d program using maximum potential throughputs for each tank.

3.8. FUGITIVE EMISSIONS

Fugitive emissions from piping components, gas releases, and truck loading occur or will occur at the Site. The methodologies used to calculate potential fugitive emissions are described in the following sections.

[13] The liquids input rate is determined based on operator experience with the incorporation of a safety factor, and the flash factor in standard cubic foot per barrel (scf/bbl) was determined in a laboratory analysis of a gas sample taken from Atlanta, Texas.

3.8.1. Fugitive Emissions from Piping Components

As part of the AB Project, Algonquin is implementing an enhanced LDAR program for pipeline liquids at the Site. This enhanced LDAR program will be in addition to the LDAR program required under 40 CFR Part 60, Subpart OOOOa that is discussed in Section 4.3.3 below. In estimating fugitive emissions for the Site, the enhanced LDAR program to be implemented is taken into consideration when calculating emissions for the piping components in pipeline liquids service (i.e., potential emissions for these components take into account an aspect of control due to the enhanced LDAR monitoring).

More specifically, potential emissions from piping components are calculated as follows:

- Piping components in natural gas service, pipeline liquids service, and in light or heavy liquid service (based on liquid vapor pressure) use emission factors from EPA's *Protocol for Equipment Leak Emission Estimates* (EPA 453/R-95-017), Table 2-4.
- Piping components in pipeline liquids service use emission factors from EPA 453/R-95-017 with the appropriate Texas Commission on Environmental Quality (TCEQ) 28RCT LDAR control efficiencies (CE) applied.[14]
- Since an emission factor is not provided for leaks from pump seals in heavy liquid service in Table 2-4, the average SOCMI without ethylene emission factor for pumps in heavy liquid service from Table 2-1 is used to estimate emissions.

The uncontrolled annual emissions are conservatively calculated assuming that the components are in continuous gas, pipeline liquids, or light or heavy liquid service as follows:

Equation 3-19:

$$\text{Total Emissions from Components in Gas, Pipeline Liquids, or Light or Heavy Liquid Service} = \#\ of\ components \times \frac{\frac{kg}{hr}}{component} \times \frac{8{,}760\ hrs}{yr} \times \frac{1{,}000\ g}{kg} \times \frac{lb}{453.6\ g} \times \frac{1\ ton}{2{,}000\ lb} = \frac{tons}{yr}$$

The controlled annual emissions are also conservatively calculated assuming that the components are in continuous pipeline liquids service as follows:

Equation 3-20:

$$\text{Total Emissions from Components in Pipeline Liquids Service} = \#\ of\ components \times \frac{\frac{kg}{hr}}{component} \times (1 - CE) \times \frac{8{,}760\ hrs}{yr} \times \frac{1{,}000\ g}{kg} \times \frac{lb}{453.6\ g} \times \frac{1\ ton}{2{,}000\ lb} = \frac{tons}{yr}$$

[14] TCEQ – Control Efficiencies for TCEQ Leak Detection and Repair Programs, Revised 07/11, https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/control_eff.doc

The emission factors utilized include emissions reductions associated with an LDAR monitoring program. Emissions of individual VOCs, GHGs, and HAPs are calculated by multiplying the total fugitive gas emissions from piping components in gas, pipeline liquids, and light or heavy liquid service by the weight percent of each pollutant in gas, pipeline liquids, and oil. Gas, pipeline liquids, and oil compositions are engineering estimates based on available worst case data to be conservative.[15]

3.8.2. Fugitive Emissions from Gas Releases

Gas releases occur with both pipeline operation and station operation. Gas releases refer to the intentional and unintentional venting of gas for maintenance, routine operations such as startup and shutdown, or during emergency conditions. The proposed Project will result in fugitive emissions from gas releases. The potential volume of gas emitted was estimated in standard cubic feet per year based on the engineering design for the proposed Weymouth Compressor Station[16] and electively implementing best management practices, including pressurized holds, to reduce gas releases from operation and maintenance activities. Additional details on gas release volume estimation are provided in Attachment G to this application. Emissions of individual VOCs, GHGs, and HAPs are calculated by multiplying the total fugitive gas emissions from gas releases by the weight percent of each pollutant in the natural gas compressed at the Site.[15]

3.8.3. Fugitive Emissions from Truck Loading

Emissions occur during the loading of volatile organic liquids into tanker trucks and include VOCs, GHGs, and HAPs. Total loading losses are calculated based on calculation methods for submerged filling provided in AP-42 Section 5.2 (version dated January 1995). Emissions of individual VOCs, GHGs, and HAPs are calculated from total loading losses using representative pipeline liquids and lubricating oil compositions.

3.9. TOTAL PROJECT EMISSIONS

Tables 3-13 through 3-16 present total potential emissions from all emission sources to be installed as a part of the AB Project at the Weymouth Compressor Station and the existing emission sources at the Weymouth M&R Station. Detailed emission calculations can be found in Attachment G of this application report.

[15] Natural gas speciation profile is based on a statistical analysis of extended gas analyses on samples of tariff-conforming pipeline quality natural gas (421 samples total) taken across Enbridge natural gas pipeline systems over the past six years (between 2011 and 2016).
[16] Since filing the last update to the application in September 2016, Algonquin has continued the design and engineering process of the Weymouth Compressor Station. Algonquin refined the estimates of gas release volumes to accord with the current design of the facility, rather than the previously used model facilities.

Table 3-13. Potential Emissions from Combustion Units at the Site

Pollutant	Taurus 60-7802 (tpy)	Waukesha Emergency Generator (tpy)	Sivalls Fuel Gas Process Heater (tpy)	Five Bruest Catalytic Space Heaters (tpy per unit)[1]	Existing Hanover Heater (tpy)	Existing NATCO Heater (tpy)	Existing Three Lochinvar Boilers (tpy per unit)[1]	Project Combustion Emissions (tpy)
	Attachment G Table							
	B-1Aj	C-1A	D-1D	D-1E	D-1A	D-1B	D-1C	
NO_X	10.03	0.39	0.10	0.03	4.03	2.88	0.29	18.45
CO	17.28	0.25	0.15	0.012	6.13	4.38	0.65	30.20
VOC	2.64	0.08	0.04	0.0025	1.48	1.06	0.06	5.49
$PM_{10}/PM_{2.5}$	1.99	0.007	0.01	0.002	0.31	0.22	0.06	2.73
SO_2	4.23	0.01	0.014	0.004	0.58	0.42	0.11	5.60
CO_2e	35,800	103	119	37	4,921	3,515	929	47,430
Total HAPs	0.80	0.05	0.008	0.0006	0.34	0.24	0.015	1.49

[1] To obtain total emissions multiply indicated value by total number of units.

Table 3-14. Potential Fugitive Emissions from the Site

Pollutant	Truck Loading Fugitive Emissions (tpy)	Piping Component Fugitive Emissions (tpy) [3]	Gas Release Fugitive Emissions (tpy) [3]	Total Project Fugitive Emissions (tpy)
	Attachment G Table			
	F-1H, F-1I, F-1J	H-1Ba	G-1B	
NO_X	--	--	--	--
CO	--	--	--	--
VOC	0.01	2.21	3.54	5.76
$PM_{10}/PM_{2.5}$	--	--	--	--
SO_2	--	--	--	--
CO_2e	1	770	3,836	4,607
Total HAPs	0.0007	0.16	0.11	0.27

Table 3-15. Potential Emissions from Parts Washer, Separator Vessels, and Storage Tanks at the Site

Pollutant	Parts Washer (tpy)	Separator Vessel SV-V01S (tpy)	Separator Vessel SV-V01C (tpy)	Separator Vessel SV-V02 (tpy)	Separator Vessel V4SD (tpy)	Condensate Storage Tank V5 (tpy)	Lubricating Oil Storage Tank OIL1 (tpy)	Oily Water Storage Tank OW1 (tpy)	Total Emissions from Parts Washer, Separator Vessels and Storage Tanks (tpy)
	Attachment G Table								
	I-1	F-1A	F-1B	F-1C, E-1A	F-1D	F-1E	F-1F	F-1G	
NO_X	--	--	--	--	--	--	--	--	--
CO	--	--	--	--	--	--	--	--	--
VOC	0.41	0.131	0.131	0.705	0.013	0.291	0.002	0.001	1.68
$PM_{10}/PM_{2.5}$	--	--	--	--	--	--	--	--	--
SO_2	--	--	--	--	--	--	--	--	--
CO_2e	--	7	7	22	1	16	--	--	53
Total HAPs	--	0.008	0.008	0.043	0.001	0.018	--	--	0.08

Table 3-16. Total Potential Emissions from the Site

Pollutant (tpy)	Combustion Sources (tpy)	Fugitive Sources (tpy)	Parts Washer, Separator Vessels, and Tanks (tpy)	Total Project Emissions (tpy)
NO_X	18.45	--	--	18.45
CO	30.20	--	--	30.20
VOC	5.49	5.76	1.70	12.95
$PM_{10}/PM_{2.5}$	2.73	--	--	2.73
SO_2	5.60	--	--	5.60
CO_2e	47,430	4,607	53	52,090
Total HAPs	1.49	0.27	0.08	1.84

This section of the application report addresses the conformity of the Site to the applicable permitting programs and air quality regulations.

4.1. TITLE V AND STATE PERMITTING REQUIREMENTS

310 CMR 7.02 provides the applicability criteria for MassDEP's state air permitting program. New or modified emission units meeting these criteria must obtain a plan approval prior to construction or operation of a new source. The new Solar Taurus 60-7802 natural gas-fired turbine will require a Non-Major CPA per 310 CMR 7.02(5)(a)2a as it is fired by natural gas and has a heat input rating greater than 40,000,000 Btu/hr. In addition, the combined fugitive emissions from the piping components and gas releases from the Site require permitting per 310 CMR 7.02(5)(a)(1) and hence are included in the Non-Major CPA application.

The new Waukesha emergency generator will meet the definition of "emergency engine" per 310 CMR 7.00 Definitions and will be operated under the ERP Certification requirements of 310 CMR 7.26(42) and 310 CMR 70.00. As such, it is not included in the attached Non-Major CPA application.

The new heaters at the Weymouth Compressor Station and the existing heaters and boilers at the Weymouth M&R Station are exempt from permitting per 310 CMR 7.02(2)(b)15, since the heat input of each heater is less than 10 MMBtu/hr. Potential emissions from the parts washer, separator vessels and storage tanks are less than one tpy for any pollutant and the units are exempt from permitting per 310 CMR 7.02(2)(b)7.

Therefore, the new emergency generator, the new fuel gas heater, the new space heaters, the new parts washer and the new separator vessels and storage tanks, and existing heaters and boilers at the Weymouth M&R Station are not addressed in the attached plan approval application forms. However, emissions from the new units are accounted for in the NSR applicability analysis provided in Section 4.2.

The following sections outline the state-specific requirements for 310 CMR 7.02(5) Non-Major CPA applications.

4.1.1. State Best Available Control Technology Applicability

Per 310 CMR 7.02(5) and MassDEP guidance,[17] a Non-Major Plan Approval application requires a Top-Down Best Available Control Technology (BACT) analysis for any new or modified emission units. Based on the MassDEP request during the initial pre-application meeting, a greenhouse gas BACT analysis is also provided with this application. The detailed BACT analysis is provided in Section 5 of this report.

4.1.2. Dispersion Modeling Requirements

Per a request from MassDEP, an ambient air quality impact analysis is provided with this application. Air dispersion modeling is relied upon to demonstrate that the Project complies with the applicable National Ambient Air Quality Standards (NAAQS). Additionally, the MassDEP requested an air dispersion modeling analysis for toxic pollutants. The detailed dispersion modeling analysis is provided as a separate report titled "Air Dispersion Modeling Report" along with application package.

[17] http://www.mass.gov/eea/docs/dep/air/approvals/aq/aqpaguid.pdf

4.2. NEW SOURCE REVIEW

The federal NSR program is comprised of two distinct pre-construction permitting programs: 1) PSD (for attainment areas/pollutants); and 2) Nonattainment New Source Review (NNSR) (for nonattainment areas/pollutants). For any new stationary source such as the Weymouth Compressor Station, these permitting programs are required to be evaluated. The applicability determination for new stationary sources involves first determining if the proposed changes/new PTE are subject to PSD and/or NNSR permitting requirements.

4.2.1. Major NSR Permitting Programs

PSD permitting may apply to facilities located in areas designated as in attainment with the National Ambient Air Quality Standards (NAAQS). Projects that are either new major stationary sources or modifications to existing major sources resulting in a significant emissions increase AND a significant net emissions increase of an attainment pollutant are subject to the PSD permitting program. The MassDEP is delegated authority to implement the federal PSD program at 40 CFR 52.21.

NNSR permitting may apply to facilities located in areas that are designated as not in attainment with the NAAQS for a specific criteria pollutant. Projects that are either new major stationary sources or modifications to existing major sources resulting in a significant net emissions increase of a nonattainment pollutant are regulated under the NNSR program in Massachusetts. MassDEP's NNSR permitting program is established in 310 CMR Appendix A.

4.2.2. NAAQS Attainment Status

The Weymouth Compressor Station will be a new compressor station located in Norfolk County, Massachusetts which is in serious nonattainment for ozone and in attainment for all other pollutants per 310 CMR 7.00 Definitions and 40 CFR 81.322, Subpart C – Section 107.

4.2.3. Major Source Status under NSR and Title V

In accordance with 40 CFR 52.21 and 310 CMR Appendix A, determination of whether NNSR/PSD applies to a project is a two-step process. The first step in completing a PSD/NNSR applicability analysis is to determine if a project is currently considered a major stationary source. The second step requires the determination of whether the proposed changes/project causes a significant emissions increase AND a significant net emissions increase, which involves the quantification of the change in emissions resulting from the project itself plus any other contemporaneous changes in emissions (i.e. increases or decreases in actual emissions) that have occurred at the facility. Projects that do not trigger NSR major source status (i.e. the first step of the process) do not trigger NNSR/PSD and are exempt from the second step of the process.

According to 40 CFR 52.21(b)(1)(i)(b), the major source threshold for PSD review is 250 tpy for any regulated NSR pollutant.

For nonattainment pollutants, MassDEP defines a major stationary source in 310 CMR Appendix A which establishes the major source threshold at 100 tpy for any regulated NSR pollutant except for VOC and NO_X, which have a lower threshold of 50 tpy each in a serious ozone nonattainment area.

Per 310 CMR Appendix C, the Title V source threshold is 100 tpy for any air pollutant. Additionally, the Title V source threshold for greenhouse gases is 100,000 tpy CO_2e and 100 tons per year of greenhouse gases on a mass basis. The PTE from the Weymouth Compressor Station for greenhouse gases is below 100,000 tpy CO_{2e} and hence it is not subject to the Title V program. Note that per 40 CFR 52.21(b)(1)(i)(c) and 310 CMR Attachment C, fugitive emissions from a stationary source shall not be included in determining a facility's PSD and Title V major stationary source status unless the facility type is listed in the 28 defined source categories. Natural gas transmission facilities are not included in the list of 28 source categories. As such, fugitive emissions are not included in the PSD and Title V major source evaluation for the Site.

In summary, the NSR major stationary source thresholds for the Site are the following:

- For ozone precursors: NO_X – 50 tpy and VOC – 50 tpy (NNSR/Title V)
- For greenhouse gases: carbon dioxide equivalent (CO_2e) – 100,000 tpy (Title V) [18]
- All other NSR regulated pollutants: 250 tpy (PSD)
- All other NSR regulated pollutants: 100 tpy (Title V)

Since the Weymouth Compressor Station is a new compressor station, the PTE from the Project (excluding fugitive emissions) will be compared to the above mentioned NSR major stationary source thresholds. The PTE (excluding fugitive emissions) from the Site as provided in Table 3-16 is well below the PSD/NNSR as well as the Title V thresholds, as such the facility does not trigger NSR major source status and is only required to prepare a Non-Major CPA application.

4.3. NEW SOURCE PERFORMANCE STANDARDS (NSPS)

This section summarizes the applicability of NSPS regulations codified in 40 CFR Part 60 to the new turbine.

4.3.1. 40 CFR Part 60, Subpart KKKK - Standards of Performance for Stationary Gas Turbines (After February 18, 2005)

Applicability

Pursuant to 40 CFR 60. 4305(a), the Solar Taurus 60-7802 gas turbine is subject to requirements of 40 CFR 60 Subpart KKKK, because its heat input at peak load will be greater than or equal to 10 MMBtu/hr (HHV) and Algonquin will have commenced the construction of the turbine after February 18, 2005.

Emission Limits

Pursuant to 40 CFR 60.4320(a) and Table 1 to Subpart KKKK of Part 60 – Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines, the Solar Taurus 60-7802 gas turbine, which will have an HHV heat input of between 50 and 850 MMBtu/hr, will comply with a NO_X emission standard of 25 ppmvd at 15 percent O_2 as indicated by the vendor guarantee listed in Table 3-1. Subpart KKKK also includes a NO_X limit of 150 ppmvd at 15 percent O_2 or 8.7 pounds per megawatt-hour (lb/MWh) for turbine operation at temperatures less than 0 °F and turbine operation at loads less than 75 percent of peak load which the new turbine will meet.

The new Solar Taurus 60-7802 turbine will comply with an SO_2 emission standard of 0.9 lb/MW-hr gross output and will not burn any fuel that has the potential to emit in excess of 0.060 lb/MMBtu SO_2 heat input, pursuant to 40 CFR 60.4330(a)(1) and (2), respectively.

[18] In accordance with the June 13, 2014 ruling of the United States Supreme Court, the EPA no longer requires stationary sources to obtain PSD and Title V permits solely due to GHG/ CO_2e emissions.

General Compliance Requirements

Pursuant to 40 CFR 60.4333(a), the new Taurus 60-7802, its air pollution control equipment, and its monitoring equipment will be maintained in a manner that is consistent with good air pollution control practices for minimizing emissions. This requirement applies at all times including during startup, shutdown, and malfunction.

NO_X Monitoring

Pursuant to 40 CFR 60.4340(a), since the new Taurus 60-7802 will not use water or steam injection to control NO_X emissions, Algonquin will perform annual performance tests in accordance with 40 CFR 60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine (≤ 18.75 ppmvd at 15 percent O_2 or ≤ 0.9 lb/MW-hr), Algonquin may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test).[19] If the results of any subsequent performance test exceed 75percent of the NO_X emission limit, Algonquin will be required to resume annual performance testing.

Per 40 CFR 60.8(a), the initial NO_X performance test for the new Taurus 60-7802 is required to be conducted within 60 days after achieving the maximum production rate (i.e. the turbine's maximum rated heat output) , but no later than 180 days after initial startup.

SO_2 Monitoring

Pursuant to 40 CFR 60.4365(a), in order to demonstrate continuous compliance with the applicable 0.0060 lb/MMBtu potential SO_2 emissions limit, Algonquin will utilize a current, valid purchase contract, tariff sheet or transportation contract for natural gas that will specify that the maximum total sulfur content of the natural gas used at the facility is less than 20 grains per 100 standard cubic feet (gr/scf).

Reporting

Pursuant to 40 CFR 60.4375(b), since Algonquin will be conducting annual performance testing in accordance with 40 CFR 60.4340(a), a written report of the results of each performance test will be submitted to MassDEP and the U.S. EPA before the close of business on the 60th day following the completion of the performance test.

Per 40 CFR 60.7(a)(1), Algonquin will submit notification of the date construction of the new Taurus 60-7802 commenced. The submittal will be postmarked by no later than 30 days after the commencement of construction date. Per 40 CFR 60.7(a)(3), the submittal of the notification of the actual date of initial startup of the new Taurus 60-7802 will be postmarked by no later than 15 days after the initial startup date.

4.3.2. 40 CFR Part 60, Subpart GG – Standards of Performance for Stationary Gas Turbines

Pursuant to 40 CFR 60.4305(b) under 40 CFR Part 60 Subpart KKKK, since the new turbine at the Weymouth Compressor Station is subject to 40 CFR 60 Subpart KKKK, it is exempt from 40 CFR 60 Subpart GG.

---

[19] Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines, New turbine firing natural gas, >50 MMBtu/h and ≤850 MMBtu/h, 25 ppmvd at 15 percent O_2 or 150 ng/J of useful output (1.2 lb/MWh).

4.3.3. 40 CFR Part 60, Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution

On December 31, 2014, the U.S. EPA finalized amendments to the NSPS for Crude Oil and Natural Gas Production, Transmission, and Distribution (40 CFR 60, Subpart OOOO). Affected sources under Subpart OOOO include storage vessels in the oil and natural gas production segment, natural gas processing segment, or natural gas transmission and storage segment with VOC emissions exceeding six tpy as described in 40 CFR 60.5365(e) as well as equipment leaks at natural gas processing plants as described in 40 CFR 60.5365(f).

Since the potential VOC emissions from the new separator vessels and storage tanks will not exceed six tpy, the Project is not subject to the requirements of Subpart OOOO.

Per 40 CFR 60.5365(f)(2), equipment leaks from process units located at onshore natural gas processing plants are subject to the LDAR requirements established in Subpart OOOO. Because the Weymouth Compressor Station operates under North American Industry Classification System (NAICS) Code 486210 for the Pipeline Transportation of Natural Gas, the facility is not a natural gas processing plant and equipment leaks at the Weymouth Compressor Station are not subject to the requirements of Subpart OOOO pursuant to 40 CFR 60.5365(f)(2).

4.3.4. 40 CFR Part 60, Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

40 CFR Part 60, Subpart OOOOa applies to sources that are constructed/modified after September 18, 2015, including centrifugal compressors, reciprocating compressors, pneumatic controllers, pneumatic pumps, storage vessels, equipment leaks and sweetening units within the crude oil and natural gas sector. In the natural gas transmission segment, Subpart OOOOa has standards for each of these affected facilities, except for pneumatic pumps and sweetening units.

Centrifugal compressors with wet seals constructed after September 18, 2015 are subject to the control, recordkeeping, and reporting requirements of Subpart OOOOa. Algonquin will not be installing any centrifugal compressors with wet seals as a part of the AB Project at the Weymouth Compressor Station. In addition, no reciprocating compressors are being installed as part of the Project. Therefore, the Weymouth Compressor Station will not be subject to the rod packing replacement or control requirements for compressors. Any new natural gas pneumatic controller installed will have a bleed rate less than or equal to six standard cubic feet per hour (scf/hour), as required by Subpart OOOOa. While any tanks being installed have the potential to be subject, the potential emissions from each of the tanks proposed at the Weymouth Compressor Station as part of the AB Project are well below the six tpy threshold. As such, the requirements of Subpart OOOOa do not apply to the tanks.

Subpart OOOOa has added LDAR requirements for new or modified compressor stations in the transmission segment. As such, the fugitive emissions components at the Weymouth Compressor Station will be subject to the LDAR requirements of Subpart OOOOa. Please note that compressor station is defined in Subpart OOOOa as:

> "Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of § 60.5397a."

4.3.5. 40 CFR Part 60, Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

40 CFR Part 60, Subpart JJJJ applies to owners and operators of new or existing stationary spark ignition internal combustion engines (SI ICE) rated at greater than 25 hp that commence construction, modification, or reconstruction after June 12, 2006. Since the new emergency stationary SI ICE proposed at the Weymouth Compressor Station is greater than 25 hp, the requirements of Subpart JJJJ will apply to the Project.

4.4. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP)

This section summarizes the applicability of National Emission Standards for Hazardous Air Pollutants (NESHAP) codified in 40 CFR Parts 61 and 63. Sources of HAPs are defined as major sources (if potential emissions exceed major source thresholds) or area sources (i.e., they are not major).

4.4.1. 40 CFR Part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines

Subpart YYYY applies to major HAP sources. Per 40 CFR 63.6085, the new Solar Taurus 60-7802 gas turbine is not subject to requirements of 40 CFR 63 Subpart YYYY because the Site will be an area source of HAPs. An area source of HAPs is a source with potential HAP emissions are less than 10 tpy for any individual HAP and less than 25 tpy for the aggregate of all HAPs.

4.4.2. 40 CFR Part 63, Subpart HHH - National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities

Subpart HHH applies to major HAP sources. Per 40 CFR 63.1270(a), major sources of HAPs that engage in natural gas transmission and storage and that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company) are subject to requirements of 40 CFR Part 63 Subpart HHH. Since the Site will be an area source of HAPs, the requirements of Subpart HHH do not apply.

4.4.3. 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Subpart DDDDD applies to certain new and existing boilers and process heaters located at major HAP sources. Per 40 CFR 63.7485, since the Project will be an area source of HAPs, the new heaters at the Site will not be subject to the requirements of 40 CFR Part 63, Subpart DDDDD. Similarly, the existing heaters and boilers at the Weymouth M&R Station are not subject to Subpart DDDDD.

4.4.4. 40 CFR Part 63, Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Subpart ZZZZ applies to certain stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAPs. Per 40 CFR Part 63.6585, Subpart ZZZZ applies to existing, new, and reconstructed RICE depending on size, use. The AB Project includes the installation of one new emergency stationary RICE with a site rating greater than 500 hp at the Weymouth Compressor Station. New stationary RICE located at area sources of HAPs, such as the emergency engine proposed for the AB Project, must meet the requirements of Subpart ZZZZ by meeting the NSPS. As discussed above in Section 4.3.3, the new emergency engine proposed at the Weymouth Compressor Station is subject to the NSPS at 40 CFR Part 60, Subpart JJJJ, therefore the requirements of Subpart ZZZZ will be met.

4.4.5. 40 CFR Part 63, Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Area Sources: Industrial, Commercial, and Institutional Boilers

Process heaters are not covered under Subpart JJJJJ, therefore, the new gas-fired heaters to be installed as a part of the Project are not covered under this rule. Additionally, boilers which only burn gaseous fuel are not covered under the rule. The boilers at the existing Weymouth M&R Station burn natural gas exclusively, therefore Subpart JJJJJJ is not applicable to their operation.

4.5. ADDITIONAL APPLICABLE STATE REGULATIONS

4.5.1. 310 CMR 7.06 - Visible Emissions

This regulation contains opacity and smoke standards:

- Opacity – Not to exceed 20 percent opacity for a period or aggregate period of time in excess of two minutes during any one hour provided that, at no time during the said two minutes shall the opacity exceed 40 percent.
- Smoke – Not equal to or greater than No. 1 of the Chart for a period, or aggregate period of time in excess of six minutes during any one hour, provided that at no time during the said six minutes shall the shade, density, or appearance be equal to or greater than No. 2 of the Chart. [20]

The new turbine at the Weymouth Compressor Station will comply with the opacity and smoke limits in this rule by firing only natural gas. The proposed emergency generator and heaters and existing heaters and boilers at the Weymouth M&R Station will also be subject to the rule and will comply by burning only natural gas.

4.5.2. 310 CMR 7.09 - Dust, Odor, Construction, and Demolition

This regulation prohibits emissions which create or contribute to dust or odors that constitute a nuisance. Algonquin will comply with this requirement during the construction and operation of the facility.

4.5.3. 310 CMR 7.10 - Noise

This regulation prohibits sounds that cause a nuisance, could injure public health, or unreasonably interfere with the comfortable enjoyment of life, property, or the conduct of business. The Weymouth Compressor Station must demonstrate compliance to 310 CMR 7.10, which requires that there cannot be an increase over ambient sound levels of more than 10 decibels (A-weighted – db(A)) or produce a "pure tone" condition – when any octave band center frequency sound pressure level exceeds the two adjacent center frequency sound pressure levels by 3 decibels or more. Based on an acoustical analysis conducted by Algonquin, the Weymouth Compressor Station will comply with the requirements of this rule.

---

[20] Chart means the Ringelmann Scale for grading the density of smoke, as published by the United States Bureau of Mines.

4.5.4. 310 CMR 7.18 - Volatile and Halogenated Organic Compounds

The operation of cold solvent degreasing units (i.e., the proposed parts washer) are regulated under 310 CMR 7.18(8)(a). The requirements of this regulation include use of solvent that has a vapor pressure of less than 1 mm Hg at 20 °C, as well as other design and operation requirements. The new parts washer proposed at Weymouth Compressor Station will be subject to the requirements of 310 CMR 7.18(8)(a) for Cold Cleaning Degreasing.

4.5.5. 310 CMR 7.19 - RACT for Sources of Nitrogen Oxides Emissions

This regulation contains NO_X Reasonably Available Control Technology (RACT) standards for combustion sources located at major stationary sources of NO_X in the state (uncontrolled PTE greater than 50 tpy). The NO_X PTE from the Site is below 50 tpy and therefore the facility is not subject to this requirement. This was also discussed and confirmed with MassDEP during the pre-application meeting.[21]

4.5.6. 310 CMR 7.22 - Sulfur Dioxide Emissions Reductions for the Purpose of Reducing Acid Rain

This rule limits the SO_2 emission rate to no greater than an annual calendar average of 1.2 pounds of SO_2 per MMBtu of fuel input from a fuel utilization facility with a capacity to burn fuel at a rate greater than or equal to 100 MMBtu/hr fuel input per hour. The new turbine at the Weymouth Compressor Station has fuel input less than 100 MMBtu/hr and is not subject to this requirement.

4.5.7. 310 CMR 7.26 - Engines and Turbines

This regulation applies to non-emergency engines with a rated power output equal to or greater than 50 kW and to turbines with a rated power output less than or equal to 10 MW that are constructed, substantially reconstructed, or altered on or after March 23, 2006. The Solar Taurus 60-7802 turbine proposed at the Weymouth Compressor Station is a non-emergency turbine with an output rating of 7,700 hp (5.74 MW). The 9 ppmvd NO_X limit at 15 percent O_2 when converted to an equivalent emission rate equals 0.38 lb/MW-hr. The conversion is based on turbine performance values at an average ambient temperature of 46.65 °F. The emission limits set forth in the regulation are based on the use of selective catalytic reduction (SCR) as BACT. Based on the BACT review done for this project, SCR is not proposed for installation. Section 7.26(43)(a)2 allows units operated to compress natural gas at a pipeline compressor station to file a CPA application in accordance with the requirements of 310 CMR 7.02(5)(c) in lieu of complying with the requirements of 310 CMR 7.26(43). Algonquin has chosen to file this Non-Major CPA application in accordance with the requirements of 310 CMR 7.02(5)(c) in lieu of complying with the requirements of 310 CMR 7.26(43). Section 5.4, Turbine – NO_X BACT, outlines the BACT analysis conducted for the Project and the proposed BACT emission limits. Therefore the industry performance standards included in 310 CMR 7.26(43) are not discussed further in this application.

[21] Pre-application meeting with MassDEP (Tom Cushing, Pete Russell, Samrawit Dererie), Spectra (Reagan Mayces, Terry Doyle, Bill Welch, Owen McManus), TRC (Kate Brown) and Trinity Consultants (Wendy Merz) on March 10, 2015.

This section discusses the regulatory basis for BACT, the approach used in completing the BACT analyses, and the BACT analyses for the proposed turbine and fugitive emissions from piping components and gas releases. The MassDEP BACT forms and supporting documentation are included in Attachments C and E.

5.1. BACT DEFINITION

Per 310 CMR 7.02(5) and MassDEP guidance for a CPA application submittal, a Top-Down BACT or Top-Case BACT analysis is required for any new or modified emission units.[22] The MassDEP Top-Case BACT guidelines for simple cycle turbines (> 10 MW/hr) are based on electricity generation with SCR controls. This Top-Case BACT analysis is not directly applicable to the proposed natural gas combustion turbine at the Weymouth Compressor Station. Hence, a Top-Down BACT analysis is provided in this section.

BACT is defined in the MassDEP regulations [310 CMR 7.00 et seq.] 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 the Department (*MassDEP*),*[23] *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 emissions standard established under the New Source Performance Standards, National Emissions 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.*

A BACT analysis must also take into account energy, economic and environmental impacts, including secondary and cumulative impacts, and other costs.

To assist applicants and regulators with the case-by-case BACT process, in 1987 EPA issued a memorandum that implemented certain program initiatives to improve the effectiveness of the PSD program within the confines of existing regulations and state implementation plans. Among the initiatives was a "top-down" approach for determining BACT. In brief, the top-down process suggests that all available control technologies be ranked in descending order of control effectiveness. The most stringent or "top" control option is the default BACT emission limit unless the applicant demonstrates, and the permitting authority in its informed opinion agrees, that energy, environmental, and/or economic impacts justify the conclusion that the most stringent control option is not achievable in that case. Upon elimination of the most stringent control option based upon energy, environmental, and/or economic considerations, the next most stringent alternative is evaluated in the same manner. This process continues until a BACT is selected.

The five steps in a top-down BACT evaluation can be summarized as follows:

---

[22] http://www.mass.gov/eea/docs/dep/air/approvals/aq/aqpaguid.pdf

[23] The term air contaminant and pollutant are used throughout the MassDEP BACT guidance document. Air contaminant is the term used in MassDEP regulations and is more inclusive than the term "pollutant" which is used by EPA in its regulations. Noise and other air contaminants that may result in a condition of air pollution (e.g. nuisance) are not regulated under the federal Clean Air Act, but are included in the Massachusetts NSR Program.

- Step 1. Identify all possible control technologies
- Step 2. Eliminate technically infeasible options
- Step 3. Rank the technically feasible control technologies based upon emission reduction potential
- Step 4. Evaluate ranked controls based on energy, environmental, and/or economic considerations
- Step 5. Select BACT

5.2. BACT REQUIREMENT

Per 310 CMR 7.02(5) for a CPA permit application submittal,[24] MassDEP requires a Top-Down BACT or Top-Case BACT analysis for any new or modified emission units. The pollutants subject to the BACT analysis include NO_X, SO_2, CO, PM (including PM_{10} and $PM_{2.5}$), and VOC from the new turbine. Also, since fugitive emissions from gas releases and piping components will be permitted as part of the AB Project, a BACT analysis is required for VOC from these sources at the Site.

Note that Algonquin is proposing to install dry low NO_X combustion technology on the new turbine which will meet 9 ppmvd NO_X. Algonquin and Solar Turbines believe that $SoLoNO_X$ is not an add-on control device, but rather it is a type of combustion chamber design that is integral to the design of the entire turbine, and that 9 ppmvd is the appropriate NO_X BACT baseline for Solar Taurus 60-7802 turbine proposed at the Weymouth Compressor Station. In order to streamline the review of this permit, Algonquin is voluntarily providing a Top-Down BACT analysis for NO_X emissions. As such, Algonquin is submitting the BACT analysis for NO_X, CO, PM, SO_2, and VOC from the new turbine and VOC from gas releases and piping components fugitive emissions.

Per MassDEP request, a GHG BACT analysis is also provided even though the CO_2e emissions from the proposed facility do not exceed 100,000 tpy. The following GHG emission sources are part of the proposed project.

- Combustion Sources
  - Simple cycle natural gas-fired combustion turbine
  - Natural gas-fired heaters
  - Natural gas-fired Emergency Generator

- Process Sources:
  - Piping component leaks
  - Gas releases

- Ancillary Sources:
  - Separator Vessels
  - Condensate Storage Tank
  - Truck Loading
  - Parts Washer

The methodology used to estimate potential project emissions of GHG is described in Section 3 of this application report and detailed calculations are presented in Attachment G. Table 5-1 provides a summary of the project potential GHG emissions on both a mass and CO_2e basis from each of the affected emission units at the Site.

[24] http://www.mass.gov/eea/docs/dep/air/approvals/aq/aqpaguid.pdf

Table 5-1. Summary of GHG Potential Emissions from the Site

Emissions Unit Description	Project PTE				Percent of Total CO_2e
	CO_2 (tpy)	CH_4 (tpy)	N_2O (tpy)	CO_2e (tpy)	
Solar Taurus 60 - 7,700 bhp	35,568	17.20	0.07	35,800	68.7%
0.15 MMBtu/hr NG fired fuel heater	118.9	0.01	0.0002	119	0.2%
Five 0.058 MMBtu/hr NG fired space heaters	185	0.0035	0.0005	185	0.4%
585 bhp Emergency Generator	82	0.87	0.0002	103	0.2%
Separator vessels and Storage Tanks	0.125	2.10	NA	53	0.1%
Truck Loading	0.0009	0.023	NA	1	0.0%
Piping Components Fugitive Emissions [1]	1.1	30.77	NA	770	1.5%
Gas Releases Fugitive Emissions [1]	5.48	153	NA	3,836	7.4%
M&R Station heaters and boilers	11,197	1	0.021	11,223	21.5%
			Total	**52,090**	**100%**

[1] Site-wide emissions (includes proposed Weymouth Compressor Station and existing M&R Station).

As noted in Table 5-1, GHG emissions from the Project are predominantly driven by the compressor turbine. Therefore, the GHG BACT analysis included in subsequent sections is focused on GHG emissions from the new turbine.

5.3. BACT ASSESSMENT METHODOLOGY - TURBINE

The following sections provide detail on the assessment methodology utilized in preparing the BACT analysis for the proposed facility. As previously noted, the minimum emission limit to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source. The following NSPS or NESHAP emission limits will apply to proposed equipment and effectively set the minimum requirement for BACT for these units for certain pollutants:

- Simple Cycle Combustion Turbine
  - NO_X limit of 25 ppmvd at 15 percent O_2

5.3.1. Identification of Potential Control Technologies

Potentially applicable emission control technologies were identified by researching the EPA control technology databases, technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. MassDEP provides guidance and lists Top-Case BACT determinations made by the agency.[25] Connecticut Department of Energy and Environmental Protection (CTDEEP) maintains a state database which list state specific BACT and Lowest Achievable Emission Rate (LAER) determinations made by the agency. The US EPA Reasonably Available Control Technology (RACT)/BACT/LAER Clearinghouse (RBLC), a database made available to the public through the EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in permit actions. These technologies are grouped into categories by industry and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

Trinity performed searches of the RBLC database, CTDEEP BACT Database and MassDEP BACT Guidance to identify the emission control technologies and emission levels that were determined by permitting authorities

[25] http://www.mass.gov/eea/docs/dep/air/approvals/bactcmb.pdf

as BACT within the past ten years for emission sources comparable to the proposed sources. The following emission source categories were searched:

- Small Combustion Turbines (< 25 MW) – Simple Cycle (no waste heat recovery) – Natural Gas (RBLC Code 16.110)
- Large Combustion Turbines (> 25 MW) – Simple Cycle (no waste heat recovery) – Natural Gas (RBLC Code 15.110). As discussed below, per NSPS Subpart KKKK, only turbines with a heat input less than 850 MMBtu/hr were considered in the BACT analysis. Turbines larger than 850 MMBtu/hr have inherent design differences that can lead to inherently lower NO_X emission levels.

Upon completion of the RBLC search, Trinity then reviewed relevant vendor information, pending permit applications, and issued permits not included in the RBLC. Attachment E presents a summary table of relevant BACT determinations for the units mentioned above.

5.3.2. Economic Feasibility Calculation Process

Economic analyses were performed to compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, raw materials, and utilities.

Detailed cost analyses calculations are presented in Attachments C and E.

5.4. TURBINE – NO_X BACT

In combustion turbines, NO_X is typically formed by two fundamentally different mechanisms: fuel NO_X, and thermal NO_X. Because the turbine will fire natural gas exclusively, thermal NO_X is the primary NO_X generating mechanism applicable to the proposed project.

"Fuel NO_X" forms when the fuel bound nitrogen compounds are converted into nitrogen oxides. The amount of fuel bound nitrogen converted to fuel NO_X depends largely upon the fuel type, nitrogen content of the fuel, air supply, and turbine design (including combustion temperature). The reaction between elemental nitrogen and oxygen to form nitrogen oxides happens very rapidly. Therefore, the primary mechanisms for reducing fuel NO_X involve creating a minimum amount of excess oxygen available to react with the fuel bound nitrogen throughout the combustion process.[26]

NO_X formed in the high-temperature, post-flame region of the combustion equipment is "thermal NO_X." Temperature is the most important factor, and at flame temperatures above 2,200 °F, thermal NO_X formation increases exponentially.[27]

Nitrogen monoxide (NO) formation is inherent in all high temperature combustion processes. NO_2 can then be formed in a reaction between the NO and oxygen in the combustion gases. In stationary source combustion, little of the NO is converted to NO_2 before being emitted. However, the NO continues to oxidize in the atmosphere. For this reason, all NO_X emissions from combustion stacks are usually reported as NO_2.

---

[26] Kraft, D.L. Bubbling Fluid Bed Boiler Emissions Firing Bark & Sludge. Barberton, OH: Babcock & Wilcox. September 1998. http://www.babcock.com/library/pdf/BR-1661.pdf.
[27] Ibid.

Also, in general, technology and emissions performance data, as reviewed for this BACT analysis, has been limited to those turbines within the size range of typical compressor turbines, and specifically those the size of the turbine required for the Project. US EPA has, in support of federal regulations such as the NSPS for combustion turbines (NSPS KKKK), reviewed the NOx emissions performance data for combustion turbines of all sizes and found differing performance data for turbines based on the size of the unit.[28] Here is a direct quotation from EPA documentation, found in 70 FR 8318 (2/18/05);

> *We identified a distinct difference in the technologies and capabilities between small and large turbines.,,,, the smaller combustion chamber of small turbines provides inadequate space for the adequate mixing needed for very low NO_X emission levels.*

The EPA finalized NSPS KKKK with a breakpoint in consideration of turbine sizes greater than 850 MMBtu/hr, between 50 MMBtu/hr and 850 MMBtu/hr, and less than 50 MMBtu/hr. Since the Project turbine is within the 50-850 MMBtu/hr size range, units greater than 850 MMBtu/hr were not considered for this analysis, since as identified by EPA there are inherent design differences in units at that size and above that can lead to inherently lower NO_X emission levels.

Algonquin reviewed RBLC database entries for all natural gas-fired, simple cycle turbines less than 850 MMBtu/hr. The proposed turbine at Weymouth will utilize a simple cycle, which is common for turbines located at compressor stations. Compressor stations have no operational need for additional heat, steam, or electrical power output such as is provided from a combined cycle process which are more typically used in electric utility projects. Consistent with MassDEP guidance, the forms and tables provided in Attachment E focus on turbines of similar size to the proposed Taurus 60-7802. For RBLC database entries, Algonquin has provided detailed emission tables for all simple cycle turbines less than 25 MW.

5.4.1. Step 1 – Identification of Potential Control Techniques

NO_X reduction can be accomplished by two general methodologies: combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Several post-combustion NO_X control technologies are potentially applicable to the proposed turbine. These technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

Attachment E provides a list of potential control technologies with application on simple cycle turbines. Using the RBLC search, as well as a review of technical literature, potentially applicable NO_X control technologies for turbines were identified based on the principles of control technology and engineering experience for general combustion units.

[28] http://www.epa.gov/ttn/atw/nsps/turbine/turbnsps.html

Combustion control options include:[29]

- Water or Steam Injection
- Dry Low-NO_X (DLN) Combustion Technology (such as SoLoNO_X)
- Good Combustion Practices (base case)

Post-combustion control options include:

- EM_X™/SCONO_X™ Technology
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

Each control technology is described in detail below.

5.4.1.1. Water or Steam Injection

Water or steam injection operates by introducing water or steam into the flame area of the gas turbine combustor. The injected fluid provides a heat sink that absorbs some of the heat of combustion, thereby reducing the peak flame temperature and the formation of thermal NO_X. The water injected into the turbine must be of high purity such that no dissolved solids are injected into the turbine. Dissolved solids in the water may damage the turbine due to erosion and/or the formation of deposits in the hot section of the turbine. Although water/steam injection acts to reduce NO_X emissions, the lower average temperature within the combustor may produce higher levels of CO and hydrocarbons as a result of incomplete combustion. Additionally water/steam injection results in a decrease in combustion efficiency and increased maintenance requirements due to wear.

5.4.1.2. Dry Low-NO_X (DLN) Combustors

The lean premix technology, also referred to as dry low-NO_X combustion technology, is a pollution prevention technology that controls NO_X emissions by reducing the conversion of atmospheric nitrogen to NO_X in the turbine combustor. This is accomplished by reducing the combustor temperature using lean mixtures of air and/or fuel staging or by decreasing the residence time of the combustor. In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air reduces the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustor area. Since NO_X formation rates are an exponential function of temperature, a considerable reduction in NO_X can be achieved by the lean pre-mix system.

SoLoNO_X is a type of dry low NO_X combustion technology from Solar Turbines, a turbine manufacturer. Alternative turbine manufacturers could provide additional types of combustion technology that would be classified as BACT. However, as Algonquin has identified a turbine manufactured by Solar Turbines as part of this project, the available control technology from Solar Turbines was evaluated. Throughout this report, SoLoNO_X and dry low NO_X combustion technology may be used interchangeably when referring to the combustion turbine.

The dry low NO_X combustion technology typically do not require additional power or heat rate compared to that of units with conventional combustors. Depending on the manufacturer and product, different levels of

[29] An additional combustion control technology potentially identified was XONON which was offered by Catalytica Energy Systems. Catalytica merged with NZ Legacy in 2007 to form Renergy Holdings Inc. In November 2007, Renergy sold its SCR catalyst and management services business (SCR-Tech, LLC). Based on research, neither SCR-Tech LLC or for any company currently makes XONON. As such, it is not considered available for this BACT analysis.

efficiencies can be achieved. Specifically, for Solar Turbines, the manufacturer of the proposed Taurus 60-7802 combustion turbine, a dry low emission combustor (or $SoLoNO_X$), can reach approximately 9 – 15 ppmvd NO_X.

The proposed turbine will receive a 9 ppmvd NO_X vendor guarantee from Solar. This guarantee is possible due to improvements and refinements of several of the technologies implemented in 15 ppmvd NO_X capable turbines such as the Augmented Backside Cooled (ABC) combustor liner, parallel fuel valves, fuels system upgrades, closed loop pilot, and injector improvements. Specifically to reach 9 ppm, the control algorithm is changed to operate directly off calculated primary zone temperature allowing for more precise burner temperature control with varying ambient conditions across the load range which results in tighter control of emissions. Primary zone temperature control requires the addition of several different new measurements in the engine which are not standard for the 15 ppmvd configuration. These modifications allow for a lower vendor guarantee. Note, that the items listed above go beyond the simple replacement of dry low NO_X burners to a more efficient model. Instead, the improvements are inherent in the design of the turbine's combustion chamber itself.

5.4.1.3. Good Combustion Practices

Good combustion practices are those, in the absence of control technology, which allow the equipment to operate as efficiently as possible. The operating parameters most likely to affect NO_X emissions include ambient temperature, fuel characteristics, and air-to-fuel ratios.

5.4.1.4. EM_X/$SCONO_X$

EM_X (the second-generation of the $SCONO_X$ NO_X Absorber Technology) utilizes a coated oxidation catalyst to remove both NO_X and CO without a reagent, such as ammonia (NH_3). Hydrogen (H_2) is used as the basis for the proprietary catalyst regeneration process. The $SCONO_X$ system consists of a platinum-based catalyst coated with potassium carbonate to oxidize NO_X and CO (to CO_2). The catalyst is installed in the flue gas with a temperature range between 300 °F to 700 °F. The $SCONO_X$ catalyst is susceptible to fouling by sulfur if the sulfur content of the fuel is high. This then requires the $SCONO_X$ catalyst to be re-coated every six months to one year, with the frequency depending on the sulfur content of the fuel.[30]

Estimates of control efficiency for a $SCONO_X$ system vary depending on the pollutant controlled. California Energy Commission reports a control efficiency of 78 percent for NO_X reductions up to 2.0 ppm, and even higher NO_X reductions up to 1 ppmvd for some designs.[31]

5.4.1.5. Selective Catalytic Reduction

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and NO react to form diatomic nitrogen and water vapor. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range, the reaction can result in removal efficiencies between 70 and 90 percent.[32] SCR units have the ability to function effectively under fluctuating temperature conditions although fluctuation in exhaust gas temperature reduces removal efficiency slightly by disturbing the NH_3/NO_X

[30] BACT Analysis for JEA-Greenland Energy Center Units 1 and 2, Combined Cycle Combustion Turbines. Prepared by Black & Veatch (September 2008).
[31] California Energy Commission, Evaluation of Best Available Control Technology, Appendix 8.1E, Page 8.1E-7.
[32] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 2*, 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.

molar ratio. SCR can be used to reduce NO_X emissions from combustion of natural gas and light oils (e.g., distillate). Combustion of heavier oils can produce high levels of particulate, which may foul the catalyst surface, reducing the NO_X removal efficiency.

5.4.1.6. Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_X control technology based on the reaction of urea or NH_3 with NO_X. In the SNCR chemical reaction, urea [$CO(NH_2)_2$] or NH_3 is injected into the combustion gas path to reduce the NO_X to nitrogen and water. The overall reaction schemes for both urea and NH_3 systems can be expressed as follows:

$$CO(NH_2)_2 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$
$$4NH_3 + 6NO \rightarrow 5N_2 + 6H_2O$$

Typical removal efficiencies for SNCR range from 40 to 60 percent.[33] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000 °F.[34] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of NH_3, forming additional NO_X.

5.4.2. Step 2 - Elimination of Technically Infeasible Control Options

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

Each of the following identified technologies were determined to be technically infeasible for the proposed Taurus 60-7802 turbine.

5.4.2.1. EM_X™/$SCONO_X$™ Technology Feasibility

The EM_X™/$SCONO_X$™ catalyst system is designed to operate effectively at temperatures ranging from 300 to 700 °F. The Solar Taurus 60-7802 turbine proposed for installation will be a simple-cycle system, with an exhaust temperature of approximately 950 °F. EM_X™/$SCONO_X$™ applications on turbines with outlet temperatures this high have not been identified. Consequently, it is concluded that EM_X™/$SCONO_X$™ is not technically feasible for control of NO_X emissions from the proposed turbine.

5.4.2.2. SNCR Feasibility

The temperature range required for effective operation of this technology is above the peak exhaust temperature for the Solar Taurus 60-7802 turbine. In addition, a review of EPA's RBLC database and EPA's National Combustion Turbine Spreadsheet shows that SNCR has never been demonstrated on a turbine of this size. Therefore, SNCR is not technically feasible for control of NO_X emissions from the proposed turbine.

5.4.2.3. Water or Steam Injection Feasibility

Water or steam injection is a NO_X reduction technology that could be installed in the combustion turbine. It is determined to be technically feasible for the combustion turbine itself, and is included in the following BACT

---

[33] U.S. EPA, Office of Air Quality Planning and Standards. *OAQPS Control Cost Manual Section 4-2 Chapter 1*, 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. January 2002.
[34] U.S. EPA, Clean Air Technology Center. *Oxides of nitrogen (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina. p. 18, EPA-456/F-99-006R, November 1999.

steps. Note, water or steam injection is not an add-on control technology that could be installed downstream of the combustion turbine, meaning this is not a viable option for addition to the turbine stacks. However, it is important to note that reductions of NO_X in the combustion turbine due to water or steam injection would reduce NO_X emissions origination from the turbine.

5.4.2.4. Dry Low NO_X Combustion Technology

Dry low NO_X combustion technology is a NO_X control technology that would be integral to the combustion turbine. It is determined to be technically feasible for the combustion turbine itself. Note, dry low NO_X combustion technology is not an add-on control device that could be installed downstream of the combustion turbine, meaning this option is not a viable option for addition to the turbine stacks. However, it is important to note that reductions of NO_X in the combustion turbine due to the dry low NO_X combustion technology would reduce NO_X emissions origination from the turbine.

5.4.2.5. SCR Feasibility

SCR is a technically feasible, add-on control technology which can be installed on a turbine's stack. As such, it is considered technically feasible to install SCR as a post-combustion control device for the turbine.

5.4.2.6. Good Combustion Practices Feasibility

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the unit. This is considered technically feasible for the control of NO_X emissions from the turbine.

5.4.3. Step 3 – Rank of Remaining Control Technologies

The remaining control technologies are DLN combustion technology, SCR, water injection, and good combustion practices, which offer the control efficiencies identified in Table 5-2.

Table 5-2. Remaining NO_X Control Technologies

Rank	Control Technology	Potential NO_X Emissions (ppm) or Control Efficiency (%)
1	SCR	70% to 90%
2	Dry Low NO_X Combustion Technology (SoLoNO$_X$)	5 to 25 ppm
3	Water Injection	20 to 42 ppm (water)
4	Good Combustion Practices	Base Case

5.4.4. Step 4 – Evaluation of Most Stringent Controls

The fourth of the five steps in the Top-Down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology on the basis of economic, energy, and environmental considerations, and is described in the following sections. In this step, once an option is selected no further (i.e., lower ranking) options are assessed.

An economic analysis was conducted to determine the cost of installing an SCR past the combustion chamber on the turbine. The analysis was conducted using procedures and guidelines in U.S. EPA OAQPS, EPA Air Pollution Control Cost Manual (6th Edition), January 2002, Section 4.2, Chapter 2. The installation of an SCR on the turbine will cost approximately $41,541 per ton of NO_X removed, which is considerably higher than the MassDEP range of $11,000-$13,000.[35] As such, SCR technology is considered economically infeasible for the proposed simple-cycled combustion turbine. Attachment E contains the detailed cost analysis for the SCR. Attachment E also includes copies of the cost calculations and SCR vendor quote.

The proposed combustion turbine will be subject to NSPS Subpart KKKK, as previously discussed. NSPS Subpart KKKK provides a NO_X limit of 25 ppmvd at 15 percent O_2 for combustion turbines burning natural gas. Therefore, NSPS Subpart KKKK sets the floor of allowable NO_X BACT limits. Possible control technologies with NO_X capabilities higher than the BACT floor are no longer viable for this project, and are not evaluated further.

Therefore, DLN combustion technology, water/steam injection, and good combustion practices are the remaining control technologies for the Solar Taurus 60-7802 turbine. DLN combustion technology is the next ranked available control technology.

5.4.5. Step 5 – Selection of BACT

The next ranked NO_X control technology available for the combustion turbine is dry low NO_X combustion technology, such as SoLoNO$_X$. As a pollution prevention control method, operating SoLoNO$_X$ in the turbine would decrease NO_X emissions downstream of the turbine(s), including from the turbine exhaust stack.

Research within available literature, EPA rulemaking, recently issued permits, and BACT determinations was conducted in order to determine an acceptable NO_X BACT limitation for the compressor turbine at the Weymouth Compressor Station. The majority of units reported in the various EPA resources including the RBLC database for gas-fired simple cycle combustion turbines pertain to electrical generating turbines. Electric generating turbines, without SCR have reported significantly lower emission limits than those for compressor turbines. These sources with lower emission limits (i.e., 9 ppmvd NO_X) were found to be primarily electrical generating units, with significantly larger turbines and overall power output. These units were found to be primarily those units with a heat input capacity above 850 MMBtu/hr. As noted above, those units should not be considered based on EPA's review of the emissions performance capabilities of combustion turbines through development of NSPS KKKK.

In the review of BACT determinations, NO_X emission limits below 9 ppmvd were found to be generally associated with SCR control technology. As discussed in the previous section, SCR was found to not be cost effective for the Project at the Weymouth Compressor Station. Since this control technology has been eliminated from feasibility, the low values that are achieved via control using an SCR are not addressed further in this BACT analysis. Further scrutiny was given to those simple cycle combustion units which research found to be achieving less than 9 ppmvd NO_X at 15percent O_2, without the use of SCR. Based on BACT determinations, only one candidate site was found;

- MGM Mirage, with a permitted NO_X value of 5 ppmvd NO_X at 15 percent O_2

The unit listed above is Solar Mercury series natural gas turbine. Solar Mercury Turbines are smaller sized units than the Solar Taurus 60-7802 turbine proposed to be installed for the AB Project. Solar's Mercury turbines can achieve lower NO_X emissions by using a recuperator in the combustion turbine. This allows the turbine to provide more power at lower combustion temperatures (reducing thermal NO_x formation). Larger sized turbines such as the Solar Taurus 60-7802 generate a greater amount of waste heat and are not capable of

[35] The annual NO_X PTE has been revised from 9.96 tpy to 10.03 tpy due to the change in estimated emissions for SU/SD. This slight increase is inconsequential to the results of the economic analysis. Therefore, these numbers have not been revised.

achieving the low combustion temperatures which result in NO_X emissions in the 5 ppmvd range. In addition, the Mercury unit was permitted in warmer climates (i.e., Nevada). Solar's NO_X emission guarantee ends at a minimum temperature of 0 °F. At ambient temperatures lower than 0 °F, NO_X emissions are calculated based on the low temperature operating scenario outlined in Section 3.1.2. Because the Mercury unit has a smaller size and different design basis, this unit is not considered to be a valid point of comparison for this BACT analysis.

Completing an economic feasibility review of SoLoNO$_X$ technology is not needed as it has been determined to be BACT for other natural gas combustion turbines. Therefore, Algonquin proposes that SoLoNO$_X$ is BACT for the combustion turbine. Algonquin is proposing a two-stage limit for NO_X from the new turbine. The final BACT emission rate for the turbine will be 9 ppmvd at 15percent O_2 of NO_X. Algonquin will be the first customer of Solar's to receive a 9 ppmvd NO_X vendor guarantee for a Solar Taurus 60-7802 turbine. Other Taurus 60-7802 units have been guaranteed at 15 ppmvd NO_X (at 15 percent O_2). Because this is a new design and the resulting NO_X emissions are dependent on site-specific factors, Algonquin and Solar are requesting an extended shakedown period to fully evaluate and tune the new turbine installation to achieve the very low NO_X BACT emission rate. Based on information from the vendor, Algonquin expects a 6-month shakedown period before the 9 ppmvd technology will be installed and fully operational on the turbine. In this interim time period, Algonquin will meet a NO_X BACT emission limit of 15 ppmv at 15 percent O_2 during normal operation. The 15 ppmv NO_X limit is consistent with the BACT limits for many existing simple cycle turbines using Solar DLN technology.

Compliance with the 9 ppmvd limit will be performed through stack testing with EPA Method 7/7E. This limit corresponds to an annual NO_X limit of 10.03 tpy from the turbine.

5.5. TURBINE – CO AND VOC BACT

5.5.1. Step 1 – Identification of Potential Control Techniques

In combustion turbines, CO and VOCs are generated as a result of incomplete combustion. Attachment C provides a list of potential CO and VOC control technologies with application on simple cycle turbines. Detailed tables of BACT determinations from the MassDEP Guidelines, CTDEEP BACT Database and RBLC database are also provided in Attachment E. Candidate control options identified from the BACT database searches, permit review, and the literature review include those classified as pollution reduction techniques. CO and VOC reduction options include:

- Oxidation Catalyst
- Good Combustion Practices

5.5.1.1. Oxidation Catalyst

The rate of formation of CO and VOC during natural gas combustion depends primarily on the efficiency of combustion. The formation of CO occurs in small, localized areas around the burner where oxygen levels cannot support the complete oxidation of hydrocarbons to CO_2. VOC is emitted when some of the fuel remains unburned or is only partially burned during the combustion process. With natural gas, some organics are carried over as unreacted, trace constituents of the gas, while others may be pyrolysis products of the heavier hydrocarbon constituents. Good combustion practices include providing sufficient excess air (i.e. O_2) for complete combustion and/or staged combustion to complete combustion of CO and VOC, thereby ensuring proper air-to fuel ratios.

CO emissions resulting from natural gas combustion can be decreased via an oxidation catalyst control system. The oxidation is carried out by the following overall reaction:

$$CO + \frac{1}{2}O_2 \rightarrow CO_2$$

This reaction is promoted by several noble metal-enriched catalysts at high temperatures. Under optimum operating temperatures, this technology can generally achieve between 70 and 95 percent reduction efficiency for CO emissions.[36] An oxidation catalyst designed to control CO would provide a side benefit of also controlling VOC emissions.

Oxidation efficiency also depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.

Catalyst fouling occurs slowly under normal operating conditions and is accelerated by even moderate sulfur concentrations in the exhaust gas. The catalyst may be chemically washed to restore its effectiveness, but eventually irreversible degradation occurs. The catalyst replacement timeframe varies depending on type and operating conditions.

5.5.1.2. Good Combustion Practices

Ensuring that the temperature and oxygen availability are adequate for complete combustion minimizes CO and VOC formation. This technique includes continued operation of the turbine at the appropriate oxygen range and temperature.

5.5.2. Step 2 – Elimination of Technically Infeasible Control Options

The oxidation catalyst and good combustion controls are both technically feasible options for the control of CO and VOC emissions from the Solar Taurus 60-7802 turbine.

5.5.3. Step 3 – Rank of Remaining Control Technologies

The third of the five steps in the top-down BACT assessment procedure is to rank technically feasible control technologies by control effectiveness. The remaining control technologies are presented in Table 4-3.

Table 5-3. Remaining CO and VOC Control Technologies

Rank	Control Technology	Potential CO Control Efficiency (%)	Potential VOC Control Efficiency (%)
1	Oxidation Catalyst	70-95	50
2	Good Combustion Controls	Base Case	Base Case

5.5.4. Step 4 – Evaluation of Most Stringent Controls

The potentially feasible technologies are discussed further in this section.

5.5.4.1. Oxidation Catalyst

Environmental impacts and costs associated with the operation of an oxidation catalyst to remove CO and VOC emissions include increased downtime required for catalyst washing and hazardous material handling concerns

[36] Control efficiency range is based on data provided by gas turbine manufacturers.

during catalyst disposal. Masking or poisoning of the catalyst occurs when materials deposit on the catalyst surface and either cover the active areas (mask) or chemically react with the active areas and reduce the catalyst's reduction capacity (poison). Masking agents include sulfur, calcium, fine silica particles, and hydrocarbons. Poisoning agents include phosphorus, lead, and chlorides. These masking and poisoning agents are found in the fuel and/or lubricating oils. The effects of masking can be reversed by cleaning the catalyst (except for fine silica particles that cannot be dislodged from the porous catalyst surface). The effects of poisoning are permanent and cannot be reversed. There is also potential energy penalties associated with the use of an oxidation catalyst. Installation of a catalyst system will increase the pressure drop experienced by the turbine exhaust flow. The increased pressure drop in the exhaust of a gas turbine will impact both the heat rate and power output. There will be a fuel penalty cost to compensate for the increased heat rate as a result of the increased exhaust backpressure. In addition, implementing oxidation catalyst control may result in a reduction in turbine power output caused by the increased backpressure on the turbine.

5.5.5. Step 5 – Selection of BACT

Completing an economic feasibility review of this technology is not needed as oxidation catalyst is the first ranked control option and has been determined to be BACT for other natural gas combustion turbines. Therefore, an oxidation catalyst is proposed as BACT for CO and VOC emissions from the combustion turbine. Algonquin proposes an annual CO emission limit of 17.28 tpy and an annual VOC emission limit of 2.64 tpy for the Solar Taurus 60-7802 turbine. The annual limits are based on an oxidation catalyst control efficiency of 95% for CO and 50% for VOC. A comparison of the proposed BACT to the determinations from the MassDEP Guidelines (Top-Case BACT), the CTDEEP BACT database, and the RBLC database is included in Attachment E. The annual CO and VOC limits include startup, shutdown and low temperature operation. Note that the oxidation catalyst is not expected to be operational during the turbine's startup periods.

5.6. TURBINE - PM AND SO_2 BACT

Natural gas-fired turbines, such as the Solar Taurus proposed at the Weymouth Compressor Station, emit a relatively small amount of PM, of which the formation depends on sulfur, nitrogen and ash amounts in fuel. The emission of sulfur compounds, mainly SO_2, is very low too and is directly related to the sulfur content of the fuel.

5.6.1. Step 1 – Identification of Potential Control Techniques

Based on the BACT determinations from the MassDEP Guidelines, the CTDEEP BACT database, the RBLC database and recent permit applications for natural gas compressor stations, the following two control technologies has been identified as BACT for the control of PM and SO_2 emissions from simple cycle turbines. The detailed tables of BACT determinations are provided in Attachment E.

- Clean fuel selection
- Good combustion and operating practices

5.6.1.1. Clean Fuel Selection

Combustion of natural gas generates low PM and SO_2 emissions in comparison to other fuels due to the low ash and sulfur contents. Pipeline quality natural gas will be used for firing the combustion turbine at the Weymouth Compressor Station.

5.6.1.2. Good Combustion and Operating Practices

As previously discussed in Section 5.4.1, good combustion/operating practices imply that the unit is operated within parameters that, without significant control technology, allow the equipment to operate as efficiently as possible. A properly operated combustion unit will minimize the formation of PM and SO_2 emissions. Proper design of the combustion units concerns features such as the fuel and combustion air delivery system and the shape and size of the combustion chamber. Good operating practices typically consist of controlling parameters such as fuel feed rates and air/fuel ratios. Natural gas-fired turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. The proposed Solar Taurus 60-7802 turbine is sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

5.6.2. Step 2 – Elimination of Technically Infeasible Control Options

The use of clean fuel (i.e. natural gas) and good combustion and operating practices are both technically feasible options for the control of PM and SO_2 emissions from the proposed Solar Taurus 60-7802 turbine at the Weymouth Compressor Station.

5.6.3. Step 3 – Rank of Remaining Control Technologies

Both of the technically feasible options, use of natural gas and good combustion practices, represent the base case for the operation of Weymouth Compressor Station.

5.6.4. Step 4 – Evaluation of Most Stringent Controls

There are no associated environmental impacts with the use of natural gas as fuel and good combustion practices. An economic analysis is not required since the top ranking control technologies are selected as BACT for the control of PM and SO_2 emissions from the proposed project.

5.6.5. Step 5 – Selection of BACT

The use of pipeline quality natural gas and good combustion and operating practices are the proposed BACT for the new Solar Taurus 60-7802 turbine at the Weymouth Compressor Station. Algonquin proposes an annual $PM_{10}/PM_{2.5}$ emission limit of 1.99 tpy and an annual SO_2 emission limit of 4.23 tpy for the new Solar Taurus 60-7802 turbine. A comparison of the proposed BACT to the determinations from the RBLC database, the MassDEP Guidelines and the CTDEEP BACT database is included in Attachment E. The proposed SO_2 BACT is based on using pipeline quality natural gas with a sulfur content of 5 grains/100 scf. The annual PM and SO_2 limits include startup, shutdown and low temperature operation.

5.7. TURBINE – GHG BACT

As previously discussed, Algonquin is proposing to install a new Solar Taurus 60-7802 gas turbine as the compressor driver at the proposed Weymouth Compressor Station as part of the AB Project. The combustion of natural gas in this turbine produces GHG emissions consisting of CO_2, CH_4, and N_2O. More than 99 percent of these combustion-related GHG emissions are in the form of CO_2 on a mass basis, since each carbon atom combusted in the fuel stream essentially results in one molecule of CO_2 emissions.[37] CH_4 and N_2O emissions are byproducts of the combustion reactions and are formed in much lower quantities. Even when scaling CH_4 and N_2O by their relative GWPs, these constituents combined contribute less than one percent of the total GHG emissions (on a CO_2e basis) resulting from the combustion of natural gas and process gas. The proposed project design requires the use of natural gas as fuel for the new turbine-driven compressor as it can be locally sourced

[37] Although small fractions of fuel carbon convert to combustion byproducts such as CO, or are unreacted CH_4, the majority of carbon combusted in the fuel stream is converted to CO_2. Consequently, standard emission factors for CO_2 are developed by assuming that the fuel carbon completely oxidizes to CO_2 (i.e., oxidation factor = 1.00).

and other fuels are not readily available at the location and/or are more carbon intensive than natural gas. The proposed project does not rely on alternative or backup fuels.

A simple cycle turbine was selected as it is the most energy efficient mode of compressing natural gas that is feasible at the proposed site location. The use of a combined cycle process is infeasible for the following reasons:

- Combined cycle processes recover heat from the exhaust of the combustion turbines to produce steam as a product, and/or to drive a steam turbine generator to produce electricity. The Weymouth Compressor Station does not have any process needs or capacity for the amount of additional steam or power that would be generated in a combined cycle process.
- The compression demand at a transmission compressor station such as the proposed Weymouth Compressor Station is not stable and may fluctuate significantly. Combined cycle combustion turbines are most effective at steady, predictable loads. Further, they take time to bring on-line as the heat recovery loop must be heat saturated before power can be derived. As such, simple cycle combustion turbine is necessary for the design of this project to accommodate the rapid deployment and frequent load changes inherent in transmission compressor station operations.

In comparison to other similar compressor turbines, the Solar Taurus 60-7802 is a state-of-the-art industrial turbine that offers equivalent or better energy efficiency than other models of similar size operated in a simple cycle. With a heat rate of 7,841 Btu/hp-hr for a Taurus 60-7802 (vendor-specified performance based on the lower heating value of natural gas and 0 °F ambient temperature), the selected turbine is a highly efficient model. GHG control technologies available specifically for this type of source are reviewed further under the five step, top-down BACT analysis that follows.

5.7.1. Step 1 – Identify All Control Technologies

GHG BACT is a relatively new requirement, therefore along with typical BACT resources, the following guidance documents were also utilized for identifying and understanding potential control technologies.

- PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance);[38]
- Air Permitting Streamlining Techniques and Approaches for Greenhouse Gases: A Report to the U.S. Environmental Protection Agency from the Clean Air Act Advisory Committee; Permits, New Source Reviews and Toxics Subcommittee GHG Permit Streamlining Workgroup; Final Report;[39] and
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers.[40]

A search of the MassDEP BACT Guidance document, CTDEEP BACT database and RBLC database was performed in August 2015 to identify the emission control technologies and emission levels that were determined to be BACT by permitting authorities for emission sources comparable to the proposed facility. The following categories were searched:

- Commercial/Institutional-Size Boilers/Furnaces (< 100 MMBtu/hr) – Gaseous Fuels & Gaseous Fuel Mixtures (RBLC Code 13.000)

[38] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: March 2011). http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf
[39] http://www.epa.gov/nsr/ghgdocs/20120914CAAACPermitStreamlining.pdf (September 2012).
[40] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC: October 2010). http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf.

- Commercial/Institutional-Size Boilers/Furnaces (< 100 MMBtu/hr) – Natural Gas (includes propane and liquefied petroleum gas) (RBLC Code 13.310)
- Large Combustion Turbines (> 25 MW) – Simple Cycle (no waste heat recovery) (RBLC Code 15.100)
- Large Combustion Turbines (> 25 MW) – Simple Cycle (no waste heat recovery) – Natural Gas (includes propane & liquefied petroleum gas) (RBLC Code 15.110)
- Large Internal Combustion Engines (> 500 hp) – Natural Gas (includes propane & liquefied petroleum gas) (RBLC Code 17.130)

Upon completion of this search, Trinity then reviewed relevant vendor information, pending permit applications, and issued permits not included in the RBLC.

The U.S. EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1. For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. As a natural gas pipeline compressor station, Algonquin proposes the use of pipeline quality natural gas only for the new turbine. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (lb/MMBtu) for a wide variety of industrial fuel types. Only landfill and other biomass gases (captured methane) and coke oven gas are shown as having lower CO_2 emissions per unit heat input than natural gas. Neither biogas nor coke oven gas is available commercially for the Weymouth Compressor Station. These fuels are commonly produced for consumption at the source where they are manufactured. Thus, it is not feasible to use these fuels at the station and they are not considered further in this analysis. In addition, Table C-2 of 40 CFR Part 98 shows that natural gas has one of the lowest emission factors for other important GHGs including CH_4 and N_2O. For this reason, Algonquin is proposing to use the available fuel type (i.e. natural gas with the lowest carbon intensity) in the new turbine at the Weymouth Compressor Station.

It should be noted that the U.S. EPA's GHG BACT requirements suggests that carbon capture and sequestration (CCS) be evaluated as an available control for projects with large amounts of potential CO_2e emissions (i.e., where CO_2e emissions levels are in the order of 1,000,000 tpy CO_2e), or for industrial facilities with high-purity CO_2 streams. The proposed project's emissions are well below the recommended threshold, and the turbine exhaust cannot be considered a high-purity CO_2 stream (turbine exhaust has a high flowrate and relatively low CO_2 concentration). Per U.S. EPA's guidance, CCS is not feasible for projects of smaller profiles such as the proposed Project.[41] Further, Algonquin was unable to identify a facility similar to the Weymouth Compressor Station where CCS technology has been successfully installed and implemented. However, as technology is currently evolving with respect to CCS, it has been included as a potentially technically feasible control technology in this analysis.

The following potential GHG emission control strategies for the proposed Taurus 60-7802 gas turbine were considered as part of this BACT analysis (Table 5-3):

- CCS
- Optimum Turbine Efficiency;
- Fuel Selection; and
- Good Combustion/Operating Practices.

---

[41] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, pages 32-33. Also, see Report of the Interagency Task Force on Carbon Capture and Storage, page 50.

Table 5-4. Potential CO_2 Control Strategies for Combustion Turbines

Control Strategy	Description
Carbon Capture and Storage (CCS)	System that captures CO_2 in the turbine exhaust and transfers it to permanent storage
Optimum Turbine Efficiency	Selection of turbine with high efficiency ratings
Fuel Selection	Combustion of low carbon intensity fuel
Good Combustion/Operating Practices	Adherence to good combustion practices

5.7.2. Step 2 – Eliminate Technically Infeasible Options

5.7.2.1. Carbon Capture and Sequestration

An effective CCS system would require three elements:

- Separation technology for the CO_2 exhaust stream (i.e., "carbon capture" technology),
- Transportation of CO_2 to a storage site, and
- A viable location for long-term storage of CO_2.

These three elements work in series. To execute a CCS program as BACT, all three elements must be 'available'.

<u>CO_2 Capture</u>

CCS would involve post-combustion capture of the CO_2 from the combustion turbine and sequestration of the CO_2 in some fashion. Carbon capture is an established process in some industry sectors, although not in the natural gas transmission sector (i.e., for compressor stations). In theory, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with either solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (slip stream) scale, and solid sorbents and membranes are only in the R&D phase.

In terms of post combustion CCS for power plants, the following projects have taken place on slip streams at coal-fired power plants:[42, 43]

1. *First Energy R.E. Burger* (Dec. 2008-Dec. 2010): First Energy conducted a CO_2 capture pilot test using Powerspan's ECO_2® technology on a 1 MWe slipstream from the outlet of the R.E. Burger Station (near Shadyside, Ohio) demonstration-scale 50 MW ECO unit (Powerspan's multipollutant control system). The ECO_2® CO_2 capture system uses a proprietary ammonia-based solvent in a thermal swing absorption (TSA) process to remove CO_2 from the flue gas. An independent review of the pilot test indicated that "technology is ready for scale-up for use in commercial scale (200 MW or larger) generating plants." To date, this technology has not been scaled up to any known commercial scale operations.[44]
2. *AES Warrior Run* (2000-Present) and *Shady Point* (1991-Present)*:* AES captures 66,000 - 110,000 tpy CO_2 using the ABB/Lummus monoethanolamine (MEA) solvent-based system from a small slipstream of the 180-320 MWe coal-fired circulating fluidized bed (CFB) power plantsat its stations in Cumberland, Maryland

[42] CCS Task Force Report, http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf , p. 31
[43] International Energy Agency GHG Research & Development Program, RD&D Database: CO_2 Capture Commercial Projects, http://www.ieaghg.org/index.php?/RDD-Database.html
[44] Powerspan, FirstEnergy ECO2® Pilot Facility, http://powerspan.com/projects/firstenergy-eco2-pilot-facility/; http://powerspan.com/technology/eco2-co2-capture/independent-review-of-eco2/.

and Panama, Oklahoma. The CO_2 is not stored, but rather is used in the food processing industry and related processes.

3. *IMC Chemicals (formerly Searles Valley Minerals)* (1978-Present)*:* IMC Chemicals captures 270,000 tpy CO_2 from the flue gas of two 52-56 MW industrial coal boilers using amine scrubbing technology at its soda ash production plant in Trona, California. The captured CO_2 is used for the carbonation of brine from Searles Lake, and the brine is subsequently used in the soda ash production process.[45]
4. *WE Energy Pleasant Prairie* (June 2008-Oct. 2009): WE Energy captured 15,000 tpy CO_2 using Alstom's chilled ammonia process from a 5 MWe slipstream of the 1,210 MW coal-fired power plant at its Pleasant Prairie station in Pleasant Prairie, Wisconsin. The literature does not suggest the CO_2 was permanently sequestered in any geologic formation or by any other means.[46]

These projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a coal fired power plant's emissions using various solvent based scrubbing processes. In addition to the coal fired power projects deploying CO_2 capture at a small scale, Florida Power & Light (FP&L) conducted CO_2 capture to produce 320-350 tpd CO_2 using the Fluor Econamine FG℠ scrubber system on 15 percent of the flue gas from its 320 MWe 2 × 1 natural gas cycle unit in Bellingham, Massachusetts from 1991 to 2005. Due to increases in natural gas prices in 2004-2005, FP&L changed from a base/intermediate load plant to a peaking plant, which made the continued operation of the capture plant uneconomical. The captured CO_2 was compressed and stored on site for sale to two nearby major food processing plants.[47, 48] Although this project indicates small-scale CO_2 capture is technically feasible for natural gas combined cycle combustion turbine flue gas, it does not support the availability of full-scale CO_2 capture from simple-cycle combustion turbines.

The projects identified do not propose post combustion capture of CO_2 from a simple cycle turbine to be used in a peaking role. Although the compressor station turbine will not function in a "peaking role" as units would for a power facility, the potential fluctuation in their operation would make implementation of post combustion capture difficult. Moreover, the projects identified are for post combustion capture on pulverized coal (PC) plants or a natural gas combined cycle combustion turbine (in one case) using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas (approximately 13-15 percent for a coal fired system versus 3-4 percent for a natural gas-fired system).[49]

In addition, prior to sending the CO_2 stream to the appropriate sequestration site, it is necessary to compress the CO_2 from near atmospheric pressure to pipeline pressure (around 2,000 psia). The compression of the CO_2 would require a large auxiliary power load, resulting in additional fuel (and CO_2 emissions) to generate the same amount of power.[50]

While carbon capture technology may be technologically available on a small-scale, it has not been demonstrated in practice for full-scale natural gas compressor stations. CCS is, therefore, not commercially

---

[45] Electrical Power Research Institute, CO2 Capture and Storage Newsletter, "Visit to the Trona plant MEA CO2 Removal System in Trona, California, in September 2006", Issue #2 December 2006, http://mydocs.epri.com/docs/public/000000000001014698.pdf.
[46] MIT Carbon Capture & Sequestration Technologies, AEP Alstom Mountaineer Fact Sheet: Carbon Dioxide Capture and Storage Project, November 23, 2011, http://sequestration.mit.edu/tools/projects/pleasant_prairie.html.
[47] International Energy Agency GHG Research & Development Program, RD&D Database: Florida Light and Power Bellingham CO_2 Capture Commercial Project, http://www.ieaghg.org/index.php?/RDD-Database.html.
[48] Reddy, Satish, et. al., Fluor's Econamine FG PlusSM Technology for CO_2 Capture at Coal-fired Power Plants, Power Plant Air Pollutant Control "Mega" Symposium, August 25-28, 2008, Baltimore, Maryland, http://web.mit.edu/mitei/docs/reports/reddy-johnson-gilmartin.pdf.
[49] CCS Task Force Report, August 2010, p. 29.
[50] CCS Task Force Report, August 2010, p. 30.

available as BACT at present for the turbine given the limited deployment of only slipstream/demonstration applications of CCS.

CO_2 Transport

In addition to the challenges presented for CO_2 capture, Since the Weymouth Compressor Station is not located near a geologic formation that would be appropriate for carbon sequestration, transportation of the CO_2 would be required. Accordingly, Algonquin is including a discussion on the feasibility of transporting the CO_2 captured from the exhaust of the turbine to an appropriate sequestration site. Algonquin would need to either transport the captured CO_2 to an existing CO_2 pipeline or transport the CO_2 to a site with recognized potential for storage (e.g., an enhanced oil recovery [EOR] site).

In its effort to identify best approaches to safely and permanently store CO_2, the U.S. Department of Energy (DOE) tasked seven Regional Carbon Sequestration Partnerships (RCSPs) for locating such areas in their respective regions.[51] The state of Massachusetts does not lie within the geographical extent of any of these RCSPs. However, the Midwest Regional Carbon Sequestration Partnership (MRCSP) is the closest RCSP covering the states of New York and New Jersey. For the analysis of available CO_2 transport options for the AB Project at the Weymouth Compressor Station, locations in MRCSP region were considered.

The Worldwide Carbon Capture and Storage Database (WCCUS) provides a map of potential storage locations. [52] All of the potential sites within the surrounding area (MRCSP region) are still in the development phase, which is likely to continue until after 2018 or did not pass validation and, as such, future phases were cancelled.[53] In reality, the closest active injection sites, which are still in development phase, are located in the Upper Peninsula of Michigan (Otsego County) and in Central Illinois, both of which are over 1,000 miles from the station. Of these two sites, the Michigan site appears to be further along in the development process and possibly open to receiving CO_2 from outside sources in the future.

Another potential site is the Triassic Newark Basin of New York and New Jersey. Currently field studies are in process to characterize the Newark Basin for its's CO_2 storage potential.[54] In addition, the New York State Geological Survey (NYSGS) has identified three potential sequestration sites in the state's oil and gas fields.[55] Projects are underway to assess evaluate the feasibility of using these site for sequestration. While the locations in New York are not active injection sites, for the purposes of this analysis, the closest potential location in New York was selected to use in the analysis.

Refer to Figure 5-1 below for a map illustrating the location of the closest potential CO_2 sequestration site.[56]

---

[51] Regional Carbon Sequestration Partnership (RCSP) Initiative. Accessed on Aug 14, 2015. http://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-infrastructure/rcsp.
[52] http://www.natcarbviewer.com/
[53] Information on the wetlands reclamation projects being considered for soil carbon sequestration is located at: http://216.109.210.162/TerrestrialDemonstrationWetlandAndMarshland.aspx.
[54] Information on the results of the Triassic Newark Basin field project is located at: http://www.netl.doe.gov/publications/factsheets/project/FE0002352.pdf
[55] http://www.nysm.nysed.gov/nysgs/research/carbon/ny.html
[56] This map is taken directly from: http://www.natcarbviewer.com/

Figure 5-1. CO_2 Potential Injection Location

The green marker indicates the location of the Triassic Newark Basin Study.

There are no known CO_2 pipelines near the station or within the region.[57,58] It is considered technically feasible to construct a CO_2 pipeline to either of these sequestration sites for the purposes of this analysis.

CO_2 Storage

The process of injecting CO_2 into subsurface formations for long-term sequestration is referred to as geologic CO_2 storage. CO_2 can be stored underground in oil/gas fields, unmineable coal seams, and saline formation. In practice, CO_2 is currently injected into the ground for enhanced oil and gas recovery. Per the CCS Task Force Report, approximately 50 million metric tons (tonnes) of CO_2 per year are injected during enhanced oil and gas recovery operations.

Within the MRCSP region, alternatives to subsurface injection have been considered but have yet to prove feasible.[59] Examples include marshlands reclamation projects in New Jersey and Maryland.

Internationally, there are three large scale projects that are currently in operation worldwide as follows:[60]

1. The Sleipner Project (1996 – current): One million tonnes of CO_2 per year is separated from produced natural gas in Norway and is injected into Utsira Sand (high permeability, high porosity sandstone) 1,100 meters below the sea surface.

---

57 http://www.majorpipe.com/?page_id=1057
58 http://www.globalccsinstitute.com/publications/global-status-ccs-2012/online/48641
59 Midwest Regional Carbon Sequestration Partnership (MRCSP) maintains a website at http://216.109.210.162/
60 CCS Task Force Report, Pages C-1 and C-2.

2. The Weyburn Project (2000 – 2011): 1.8 million tonnes of CO_2 per year is injected into 29 horizontal and vertical wells into two adjacent carbonate layers in Saskatchewan, Canada near the North Dakota border. The CO_2 originates from a nearby synfuel plant.[61]
3. The Snohvit Project (2010 – current): The Project is expected to inject 0.7 million tonnes CO_2 per year from natural gas production operations near the Barents Sea. The injection well reaches 2,600 meters beneath the seabed in the Tubasen sandstone formation.
4. The In Salah Project (2004 – current): The Project injects 1.2 million tonnes of CO_2 annually produced from natural gas into 1,800 meter deep muddy sandstone (low porosity, low permeability).

For the purposes of this analysis, it is assumed that CO_2 storage is a technically feasible option for Algonquin to employ for CO_2 emissions from the new combustion turbine at the Weymouth Compressor Station.

Based on the assumptions previously stated that CCS is technically feasible, Algonquin has provided a cost effectiveness assessment for simple cycle turbine in Section 5.7.4.

5.7.2.2. Optimum Turbine Efficiency

The affected unit for this project is as follows, with information per the specifications provided by Solar.

- A new 7,700 hp Solar Taurus 60-7802 natural gas-fired turbine-driven compressor unit.

As previously stated, the Solar Taurus 60-7802 is a state-of-the-art industrial turbine that offers equivalent or better energy efficiency than other models of similar size, operated in a simple cycle. With a heat rate of 7,841 Btu/hp-hr (vendor-specified performance based on the lower heating value of natural gas and 0 °F ambient temperature), the selected turbine is a highly efficient model. The Solar Taurus 60-7802 is a simple cycle design. As previously discussed, a combined cycle turbine is not appropriate for the proposed project.

5.7.2.3. Fuel Selection

The fuel for firing the combustion turbine is natural gas only. As discussed in Section 5.7.1, natural gas has the lowest carbon intensity of any available fuel for such unit and its use is technically feasible for this project.

5.7.2.4. Good Combustion/Operating Practices

Good combustion/operating practices are a potential control option for optimizing the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure an effective staging of air/fuel ratios in the turbine to maximize fuel efficiency and minimize incomplete combustion. Furthermore, the proposed turbine is sufficiently automated to ensure optimal fuel combustion and efficient operation leaving virtually no need for operator tuning of these aspects of operation.

5.7.3. Step 3 – Rank Remaining Control Options by Effectiveness

The following control options remain and are ranked by their effectiveness in reducing CO_2 emissions from the turbine. Details of these technologies are provided in Step 1.

- CCS, 90 percent[62]

[61] Petroleum Technology Research Centre, http://www.ptrc.ca/weyburn_overview.php
[62] Capture efficiency of 90% is assumed by NETL in its costing document, *Estimating Carbon Dioxide Transport and Storage Costs*, Page 9. http://netldev.netl.doe.gov/research/energy-analysis/publications/details?pub=d9585d27-1433-463a-87d1-9d791b62cf72.

- Use of high efficiency turbines, fueled by natural gas and employing good combustion/operating practices (Base Case).

In terms of comparing relative heat rates and efficiencies, similar models and sizes of industrial simple cycle gas turbines suitable for use in natural gas compression from leading manufacturers are ranked by efficiency in Table 5-4 below.

Table 5-5. Comparison of Turbine Heat Rates and Efficiencies

Manufacturer	Model	Output (hp)	Heat Rate (Btu/hp-hr)[63]	Efficiency
Solar[64]	Taurus 60	7,700	7,840	32.4%
General Electric[65]	NovaLT5-2	7,509	8,304	31.5%
Siemens[66]	SGT-100	7,640	7,738	32.9%

As shown, the Solar Taurus 60-7802 turbine is one of the most efficient models of generally available mechanical drive turbines in the needed HP range presented. The Solar model also has the advantage of a lower vendor-guaranteed NO_X emission rate than the other models shown.

5.7.4. Step 4 – Evaluation of Most Stringent Controls

The energy, environmental, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2).

As the most stringent control option available, CCS would be considered BACT, barring the consideration of its energy, environmental, and/or economic impacts. However, for the reasons outlined in this section, this option should not be relied upon as BACT and the next most stringent alternative evaluated.

Notwithstanding the information above, Algonquin has opted to include a cost feasibility assessment for use of CCS to support the argument that while CCS could be considered to be technically feasible, it is not a viable option for this project. The costs associated with CCS can be broken down into the same three categories that the CCS process is divided: CO_2 capture, CO_2 transport, and CO_2 storage.

5.7.4.1. Carbon Capture Costs

Carbon capture costs have been estimated using published articles and government resources in the absence of cost data or specific technology details for the capture of CO_2 from commercial applications. Capture and compression costs vary widely depending on what type of combustion equipment and process is used at the

[63] As reported by the manufacturers at ISO conditions, for shaft output, and based on LHV of natural gas.
[64] Solar Turbines, Taurus 60 Gas Turbine Compressor Set, General Specifications, https://mysolar.cat.com/cda/layout?m=41425&x=7
[65] GE Energy Gas Turbine Data Sheet – Mechanical Drive, https://www.geoilandgas.com/sites/geog.dev.local/files/ge_novalt5_brochure.pdf
[66] SGT-100 Industrial Gas Turbine – Mechanical Drive, Specifications Sheet, http://www.energy.siemens.com/hq/pool/hq/power-generation/gas-turbines/downloads/Industrial%20Gas%20Turbines/Industrial_Gas_Turbines_EN_new.pdf

facility. Of the plant configurations for which cost factors are provided in the CCS Task Force Report, the factor for a new natural gas combined cycle facility, while not the same process, is taken to be the most pertinent with respect to the Weymouth Compressor Station. Capture and compression costs typically use either a "CO_2-captured" or a "CO_2-avoided" basis. The CO_2-captured basis accounts for all CO_2 that is removed from the process as a result of the installation and use of a control technology, without including any losses during transport and storage or emissions from the control technology itself. A CO_2-avoided basis takes into account the CO_2 losses during transport and storage as well as CO_2 emissions from equipment associated with the implementation of the CCS system. It is more appropriate to use the CO_2-captured monetary estimates because the BACT analysis is based on emissions from a single source (e.g., the direct emissions from the simple cycle combustion turbine) and does not account for secondary emissions (e.g., the GHG emissions generated from the act of compressing the CO_2 to pipeline pressures). As such, the cost factor which uses a CO_2-captured basis is selected for use in this analysis. It should also be noted that for this analysis, the factors which appear in the CCS Task Force Report have been converted from a metric tons basis to a short tons basis and scaled from December 2009 dollars to August 2015 (current) dollars using appropriate price indices.[67] A ten year lifespan is used for the capital calculations because the acidic nature of CO_2 will deteriorate the equipment at a more aggressive rate.

5.7.4.2. Carbon Transport Costs

The cost of pipeline installation and operation are obtained from the National Energy Technology Laboratory (NETL)'s Document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447.* Per this document, the pipeline costs include pipeline installation costs, other related capital costs, and operation and maintenance (O&M) costs.

As noted in Section 5.7.2, the closest carbon sequestration site, which is still in the experimental phase, is the Newark Basin. It is located approximately 180 miles from the Weymouth Compressor Station. For cost estimation purposes, a pipeline length of 180 miles is assumed for a CO_2 transfer pipeline straight from the Project site location to the carbon sequestration site. The required diameter for the pipeline was estimated using the publication by MIT titled "Carbon Management GIS: CO2 Pipeline Transport Cost Estimation". [68] It was estimated that a four-inch diameter pipeline would be appropriate for this transport need.

5.7.4.3. Geological Storage Costs

The NETL's *Estimating Carbon Dioxide Transport and Storage Costs* document contains the average saline formation depths and capacities. As previously indicated in the transportation section, the storage location included in this analysis is a gas or oil reservoir, which may have different dimensions than a saline formation. However, due to the small impact on overall calculations and the small amount of CO_2 being sequestered, this is considered to be a reasonable estimate. Based on the published information, the average storage site depth is 1,236 meters and each injection well is able to accommodate an average of 10,320 tpd. The Weymouth Compressor Station would be sequestering 97 tpd, and therefore would only require one injection well. It should be noted that differences in formation properties could have a significant effect on the project design, such as limiting the throughput to a well, thereby increasing the number of wells needed and increasing storage costs. However, due to the uncertainty of the effect of the differences in the storage formations, the storage costs estimated in the NETL guidance are used in this analysis in order to not overestimate costs.

---

[67] Price indices are obtained from the Producer Price Index published by the U.S. Bureau of Labor Statistics. PPI values obtained from historic tables. Accessed online 08/18/2015 at http://www.bls.gov/

[68] Carbon Capture and Sequestration Technologies Program Massachusetts Institute of Technology. Carbon Management GIS: CO2 Pipeline Transport Cost Estimation. October 2006, Updated in June 2009.

5.7.4.4. Overall Cost of Carbon Capture and Sequestration

The estimated total cost for the capture of CO_2 emissions from the turbine, the cost to transport the CO_2 from the turbine to an appropriate storage facility, and the cost to sequester the resulting supercritical fluid is estimated to be $709 per ton of CO_2 captured. Considering the quantity of CO_2 generated, this figure represents an unreasonable cost for GHG control that Algonquin believes is not cost effective.[69]

In addition to the direct costs included in the previous section, the energy and environmental impacts would not be insignificant. The flue gas stream from the turbine stacks is significantly lower in CO_2 concentration than exhaust streams from the projects discussed above that have been used for demonstrating capture of CO_2 for sequestration. As such, additional processing of the exhaust gas would be required in order to implement CCS for the AB Project. These steps include separation (removal of other pollutants from the waste gases), capture, and compression of CO_2 at both the Weymouth Compressor Station and at the wellhead, transfer of the CO_2 stream and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipeline. These units would require additional electricity and generate additional air emissions, of both criteria pollutants and GHG pollutants.

Algonquin also anticipates significant additional costs to inquire about and secure a carbon storage site that is within a reasonable distance and that will accept the CO_2 stream. Based on the research conducted for this analysis, it will likely be difficult to find an available storage location. Algonquin would also incur significant cost to obtain rights and permitting for an additional pipeline to handle the CO_2 transport to the wellhead.

For multiple reasons, including the uncertainty of locating a carbon storage site, the undue burden of applying a technology that has yet to be proven for gas turbines, and the excessive cost to implement this technology, CCS is eliminated from further review.

Use of high efficiency turbine, fueled by natural gas and employing good combustion/operating practices are the remaining control technologies and represent the base case.

5.7.5. Step 5 – Selection of BACT

Establishing an appropriate averaging period for the BACT limit is a key consideration under the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Since localized short-term health and environmental effects from GHG emissions are not recognized, Algonquin proposes only annual GHG BACT limits. The resulting BACT standard is a proposed annual emissions limitation of 35,800 tons CO_2e/year/turbine for the new turbine. The annual CO_2e limit includes startup, shutdown and low temperature operation. Because the tpy CO_2e emission rate from the turbine is lower during startup and shutdown than during normal operation, Algonquin proposes that the requested BACT limit applies at all times. Because cold weather operation of the turbine may result in instantaneous lb

[69] For comparison, U.S. EPA evaluated a PSD application from ETC Texas Pipeline, Ltd, submitted March 15, 2012, for a gas processing plant in Ganado, TX. In its application, ETC Texas Pipeline evaluated the cost of an 8-inch diameter, 120-mile CO_2 pipeline using the same document from NETL. ETC found the control cost per ton associated with CO_2 transport to be $80.80 per ton of CO_2. On May 24, 2012, U.S. EPA issued a final permit that did not require CCS for this facility. Calpine Corporation also submitted a GHG PSD application to U.S. EPA for a gas-fired power station at the Deer Park Energy Center on September 1, 2011. Calpine estimated the costs of post-combustion CCS at the facility to be between $44.11 and $103.42 per ton of CO_2, using scalable cost estimation methods for gas-fired power stations. In its statement of basis for its draft permit issued August 2, 2012, U.S. EPA stated that CCS at this facility would be "financially prohibitive due to the overall cost of GHG control strategies."

CO_2e/hr emission rates higher than the proposed annual average limit and conversely lower in warm weather operation, the requested BACT limit is only appropriate on a 12-month rolling average basis. For compliance purposes, CO_2e emissions are calculated using the global warming potentials listed under 40 CFR part 98, Table A-1, as Algonquin will be required to use these global warming potentials in calculating annual GHG emissions for submittal under 40 CFR Part 98(a)(2).

Through the proposed BACT limit, Algonquin limits the maximum fuel consumption and CO_2 emissions, effectively requiring efficient operation at the design heat rate, when operating at 100 percent load (as inefficient turbine operation would require additional fuel consumption which is undesirable from an operator's perspective). Algonquin will operate turbine under an Operations and Maintenance (O&M) Plan to ensure that the units are operated in accordance with recommended good combustion practices such that optimum efficiency is maintained. Furthermore, the proposed unit contains modern process control technology that continually seeks optimum efficiency from the turbine.

5.8. FUGITIVE EMISSIONS FROM PIPING COMPONENTS - VOC BACT

The following section presents the Top-Down BACT analysis for VOC emissions from new piping components that will be installed at the Site. Piping components that produce fugitive emissions include: valves, pressure relief valves, pump seals, compressor seals, and sampling connections.

5.8.1. Step 1 – Identification of Potential Control Technologies

In determining whether a technology is available for controlling VOC fugitive emissions from piping components, available permits, permit applications, industry guidance, MassDEP BACT guidelines and EPA's RBLC database were consulted. Based on these resources, the following available control technologies were identified:[70]

- "Leakless technology" piping components instead of traditional components;
- Leak detection and repair (LDAR) program; and
- Audio/visual/olfactory (AVO) monitoring program.

It should be noted that the only fugitive VOC control technology identified by the RBLC database is the use of an LDAR program. However, there are no natural gas transmission compressor stations listed in the RBLC at the time of submittal of this application.

5.8.2. Step 2 – Elimination of Infeasible Options

5.8.2.1. Leakless Technology

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellow valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions. Further, it is not accurate to assume that "leakless" components do not leak over the lifetime of the component or that their use would result in zero emissions. In the September 27, 2013 response to Sierra Club's comment letter on draft permit PSD-TX-102982-GHG, ExxonMobil stated that, "For example, the valve packing configurations noted by the BAAQMD permits for refineries noted by the Sierra Club, such as bellow sealed valves and live loaded packed valves do leak. Bellow

---

[70] https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/exxonmobil-baytown-response092713.pdf

seals can fail, live load packing wears and leaks, etc."[66] In addition, high process temperatures can cause degradation of leakless components, such as bellow valves, which can reduce the useful life of the component. Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of the low levels of VOC emissions generated from piping components at the Site and will not be considered further in this analysis.

5.8.2.2. LDAR

LDAR programs using instrument or imaging-based detection of leaks are well-established for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these programs. As such, LDAR technology based on EPA Method 21 or optical gas imaging (OGI) is considered technically feasible for this project.

5.8.2.3. AVO Methods

Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods. The natural gas that passes through the Site is odorized and therefore natural gas leaks from components are expected to have discernible odor to some extent, making them detectable by olfactory means. A large leak can be also detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. As such, AVO methods (including audio or visual) are considered technically feasible for this project.

5.8.3. Step 3 – Rank of Remaining Control Technologies

The following list provides a ranking of the remaining control technologies based on their approximate control efficiencies:

- LDAR Programs – 40 – 97 percent efficient depending on the component type[71,72]
- AVO Methods – control efficiency unknown for natural gas service

Audio/visual/olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. The Weymouth Compressor Station is classified as an unmanned site. While someone may be present at the site during the daytime work shift, there are periods during which no one will be at the site. Further, AVO is typically used for inorganic/odorous and low vapor pressure compounds such as chlorine, ammonia, hydrogen sulfide, and hydrogen cyanide. This method cannot generally identify leaks at as low a leak rate as instrumented readings or imaging can identify and therefore it is generally used to

---

[71] Per Technical Support Document for NSPS OOOO, this is based on emission reductions at refineries that were obtained for various components from EPA's recently collected data for the Uniform Standards. In the Technical Support Document, EPA states that this data represents the most up-to-date information that is available for equipment leaks from the oil and gas sector. The reductions do not include uncontrolled piping components less than two inches in diameter. The NSPS OOOO technical support document references a Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, EPA-HQ-OAR-2002-0037-0180 as the basis for these reductions.

[72] Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Background Technical Support Document for the Final New Source Performance Standards 40 CFR Part 60, Subpart OOOOa, EPA-HQ-OAR-2010-0505-7631, May 2016, p. 41 estimates the overall reduction efficiency from Subpart OOOOa to be 80 percent based on quarterly monitoring.

supplement an LDAR monitoring program. As such, its effectiveness as a stand-alone control technology is relatively low for the Site and therefore is ranked below LDAR programs.

5.8.4. Step 4 – Evaluation of Most Stringent Controls

Environmental impacts associated with the implementation of LDAR are minimal. Completing an economic feasibility of this technology is not needed as this is the first ranked control options and Algonquin proposes to implement it at the Site.

5.8.5. Step 5 – Selection of BACT

Algonquin proposes to comply with the Subpart OOOOa requirements for components in natural gas service, as applicable, at the Site. In addition, as detailed in Section 3.8.1 Algonquin will utilize an enhanced LDAR program for the piping components in pipeline liquids service at the Site. Algonquin proposes an annual VOC emission limit of 2.21 tpy for the piping components fugitive emissions. The VOC emission limit is based on the use of control efficiencies for Texas Commission on Environmental Quality (TCEQ) LDAR program 28 RCT for the piping components in pipeline liquids service at the Site.

5.9. EMISSIONS FROM GAS RELEASES – VOC BACT

Gas releases refers to the intentional and unintentional venting of gas for maintenance, routine operations such as startup and shutdown, or during emergency conditions. Algonquin estimates that the natural gas that is released during these events contains less than 10 percent VOC by weight. Potential emissions from gas releases at the Site are based on conservative assumptions that over-predict emissions from these sources. Actual emissions from gas releases are expected to be significantly lower.

5.9.1. Step 1. Identification of Control Technologies

Based on RBLC search results and recent permit applications for natural gas compressor stations, there are no documented available technologies to reduce emissions of VOC from gas release events at natural gas compression stations.

A possible measure to reduce blowdown gases is to inject the gases into a low pressure main or a fuel gas system (i.e., drawing the pressure down). In-line and/or portable compressors may also be used to lower gas line pressure before maintenance in order to reduce emissions. This measure is known as “pipeline pump-down”.

5.9.2. Step 2. Eliminate Technically Infeasible Controls

Drawing the pressure down using a . . fuel gas system is considered infeasible for the proposed compressor station. Pressure draw-downs are not achievable without the use of equipment such as low pressure laterals or microturbines, such as those that might be present at an electric utility. Any addition of the types of equipment that would need to be present in order to draw down the pressure to reduce gas releases would change the fundamental design of the AB Project at the Site.

5.9.3. Step 3. Ranking of Technically Feasible Controls

At this single-turbine compressor station, good operating practices, along with ESD preventative measures are the only feasible control options for reducing emissions from gas release events.

5.9.4. Step 4. Evaluation of Most Stringent Controls

The environmental impacts related with the implementation of good engineering practices, along with ESD preventative measures, are minimal. Completing an economic feasibility of this technology is not needed as this is the only technically feasible control option and Algonquin proposes to implement it at the Site.

5.9.5. Step 5. Selection of BACT

Algonquin will maintain good operating practices, along with ESD preventative measures, as BACT for gas release events.

6. DISPERSION MODELING ANALYSIS

The detailed dispersion modeling analysis is submitted as a separate report, titled "Air Dispersion Modeling Report" along with this application package.

7. NOISE SURVEY

The noise survey report is included as Attachment F to this application package.

Massachusetts Department of Environmental Protection

Supplemental Transmittal Form

(to accompany supplemental material or payment to previously submitted DEP permit applications)

1. Transmittal Number	Obtain from the upper right hand corner of the original application's Transmittal Form:
	X266786

2. Facility Information	(a) Facility Name:	(b) Facility Address:
	Weymouth Compressor Station	50 Bridge Street
	(c) Facility Town/City	(d) Telephone Number:
	Weymouth, MA 02191	713-627-5400

3. Permit Information	(a) Permit Name:	(b) Permit Code: (from original application)
	Non-Major CPA Fuel and Non-Major CPA Process	BWP AQ 02

4. Reason For Supplemental Submission	☐	(a) Response to Request for Additional information	☐	(b) Response to Statement of Deficiency
	☐	(c) Supplemental Fee Payment	☐	(d) Withdrawal of Application
	☒	(e) Other (please specify below): Algonquin is submitting a revised Non-Major CPA application for the Weymouth Compressor Station to reflect refinements in turbine vendor emissions estimates, compressor station design, and gas quality data, which have occurred since the previous submittal.		
		Change in project scope		

5. Form Prepared by	(a) Name of individual or firm preparing this submission:	(b) Affiliation with application, i.e. applicant, consultant to applicant:
	Trinity Consultants	Consultant
	(c) Contact Name:	(d) Contact Telephone #:
	Wendy Merz	610-280-3902 x 301

ATTACHMENT B: BWP AQ 02 NON-MAJOR CPA FORMS

BWP AQ 02 Non-Major CPA-FUEL
BWP AQ 02 Non-Major CPA-PROCESS

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)

X266786
Transmittal Number

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

Weymouth Compressor Station
1. Facility Name

50 Bridge Street
2. Street Address

Weymouth
3. City

MA
4. State

02191
5. ZIP Code

6. MassDEP Account # / FMF Facility # (if Known)

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

4922
8. Standard Industrial Classification (SIC) Code

486210
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)
N/A			

*CO = carbon monoxide, CO_2 = carbon dioxide, NOx = nitrogen oxides, SO_2 = sulfur dioxide, VOC = volatile organic compoun
HAP = hazardous air pollutant, PM = particulate matter, specify if “Other”

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:

   The proposed project includes the installation of one (1) Solar Taurus 60 natural gas turbine compressor unit (7,700 hp), a Waukesha VGF24GL natural gas fired emergency generator (585 hp), a fuel gas process heater (0.23 MMBtu/hr heat input), five fuel gas space heaters (0.072 MMBtu/hr heat input) a parts washer, new separator vessels and storage tanks and a gas cooler for the station.The new compressor turbine will be equipped with Solar's SoLoNOx technology to control emissions of NOx, CO and other air pollutants. Additionally, this application is including the operation of the existing metering and regulation (M&R) station as part of the facility.

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

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)
N/A					

[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)
EU1 ☒ New ☐ Modified	Solar Taurus 60-7802 natural gas turbine*	74,910,000*	Natural Gas	N/A
☐ New ☐ Modified				
☐ New ☐ Modified				
☐ New ☐ Modified				

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)
EU1	73,444 scfh*	**6.46 MW***

* Maximum heat input rating, maximum firing rate, and maximum output rating for EU1 is for low temperature conditions. See Table B-1Ah in Attachment G

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

Table 6a

Air Pollution Control Devices (PCDs), you must also submit the applicable Supplemental Form(s). See Page 6 for additional information.

Description of Proposed PCD	Emission Unit No(s). Served by PCD	Air Contaminant(s) Controlled	Overall Control (Percent by Weight)
The proposed turbine is equipped with SoLoNOx to control emissions ☒ New ☐ Existing	EU1	VOC	
		CO	
		PM[1]	
		NO_x	N/A[1]
		NH_3	
		Other:	

[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	EU1	VOC	50%
		CO	95%
		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.

[1] Algonquin and Solar Turbines believe that SoLoNOx is not an add-on control device, but rather it is a type of combustion chamber design that is integral to the design of the entire turbine, and that 9 ppm is the appropriate NO_x BACT baseline for Solar Taurus 60-7802 turbine proposed at the Weymouth Compressor Station.

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

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.

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).

Table 7			
Emission Unit No.	**Type of Noise Suppression Equipment** (e.g. Mufflers, Acoustical Enclosures)	**Equipment Manufacturer**	**Equipment Model No.**
EU1	Acoustical Enclosure (Building)	N/A	N/A
EU1	Turbine Exhaust Silencer	TBD	TBD
EU1	Air Intake Silencer	TBD	TBD

Note: TBD = To Be Determined

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:

No visible emissions from the proposed project will be expected due to the nature of operations and use of natural gas as fuel.

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

No odor impacts from the proposed project will be expected due to the nature of operations and use of natural gas as fuel.

C. Stack Description

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.

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

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**
EU1	60	15	9.027	865-999	25-28	Steel

D. Best Available Control Technology (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.

1. Complete the table(s) below to summarize the proposed project's BACT emissions.

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])[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][3]	**Proposed Monthly Time Period Emissions Restrictions** [4] (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. EU1 Fuel Used Natural Gas	PM[1]	0.48 lbs/hr	0.0066 lb/MMBtu	1.99	0.18	N/A
	$PM_{2.5}$	0.48 lbs/hr	0.0066 lb/MMBtu	1.99	0.18	N/A
	PM_{10}	0.48 lbs/hr	0.0066 lb/MMBtu	1.99	0.18	N/A
	NO_x[2]	2.38 lbs/hr	9 ppmvd at 15% O_2	10.03	0.94	N/A
	CO	4.02 lbs/hr	1.25 ppmvd at 15% O_2 or 0.20 lbs/hr[5]	17.28	2.18	N/A
	VOC	0.50 lbs/hr	0.25 lbs/hr	2.64	0.30	N/A
	SO_2	1.03 lbs/hr	5 grains per 100 scf NG	4.23	0.37	N/A
	HAP[3][6]	0.17 lbs/hr	N/A	0.42	5.26E-02	N/A
	Total HAPs[3]	0.25 lbs/hr	N/A	0.80	0.1	N/A
	CO_2[4]	8,631 lbs/hr	N/A	35,568	3,148	N/A

[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.

[2] The uncontrolled emission rates are based on maximum hourly emission rates for normal operations after SoLoNOx but before oxidation catalyst. Algonquin and Solar Turbines believe that SoLoNO$_X$ is not an add-on control device, but rather it is a type of combustion chamber design that is integral to the design of the entire turbine. For emission rates during startup, shut down and low temperature operations, please refer to Attachment G.
[3] Values represent the proposed emissions (tpy) after the implementation of an oxidation catalyst on the turbine.
[4] Proposed tons per month (tpm) emissions are the worst case emissions calculated for a month with 31 days of operation, including 12 hours of low temperature operation between -20 °F and 0 °F and 52 events of startup and shutdown.
[5] Equivalent to 1.25 ppmvd CO at 15% O_2 based on use of an oxidation catalyst with a 95% control efficiency for CO.
[6] Formaldehyde emissions are presented for worst-case Individual HAP.

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. Fuel Used	PM					
	$PM_{2.5}$					
	PM_{10}					
	NO_x					
	CO					
	VOC					
	SO_2					
	HAP					
	Total HAPs					
	CO_2					

X266786
Transmittal Number

Facility ID (if known)

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.	PM					
	$PM_{2.5}$					
	PM_{10}					
	NO_x					
	CO					
	VOC					
	SO_2					
	HAP					
	Total HAPs					
	CO_2					

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..

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
EU1	Performance Test	NOx emission rate	Initial and Annual
EU1	Performance Test	CO emission rate	Initial
EU1	Purchase Contract	Sulfur Content of the natural gas used at the facility	N/A

[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)
EU1	NOx and CO Emissions	Copy of compliance test reports	As conducted
EU1	Emissions	Calculation of emissions	Monthly and 12-month rolling

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
- ☐ Combustion Equipment Standard Maintenance Procedures, Including Cleaning Method & Frequency
- ☒ Calculations to Support This Plan Application
- ☒ Air pollution control device manufacturer specifications, if applicable
- ☐ Air pollution control device standard operating procedures, if applicable
- ☐ Air pollution control device standard maintenance procedures, if applicable
- ☒ 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.

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? **JJJJ, KKKK** Applicable emission limitation(s): **NOx - 25 ppm @ 15% O2**

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAPS) ☐ Yes ☒ No

If Yes: Which subpart? Applicable emission limitation(s):

Continue to Next Page ►

40 CFR 63: NESHAPS for Source Categories – Maximum Achievable (MACT) or Generally Available (GACT) Control Technology ☒ Yes ☐ No

If Yes: Which subpart? Applicable emission limitation(s):

301 CMR 11.00: Massachusetts Environmental Policy Act (MEPA)? ☐ Yes ☒ No

If Yes: EOEA No.:

Other Applicable Requirements? ☐ Yes ☒ No

If Yes: Specify:

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.

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.

Lynne P. Santos
P.E. Name (Type or Print)

Lynne P. Santos
P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Thomas V. Wooden
Responsible Official Signature

VP- Field Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/17/2018
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 (this is a new facility)

   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

[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

Massachusetts Department of Environmental Protection

Bureau of Waste Prevention – Air Quality

CPA-PROCESS (BWP AQ 02 Non-Major, BWP AQ 03 Majo

Comprehensive Plan Application for Process Emission Unit(s)

For Process Equipment Emitting 10 Tons or More of an Air Contaminant per Consecutive 12-Month Time Period.

X266786
Transmittal Number

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.

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

A. Facility Information

Weymouth Compressor Station
1. Facility Name

50 Bridge Street
2. Street Address

Weymouth
3. City

MA
4. State

02191
5. ZIP Code

6. MassDEP Account # / FMF Facility # (if Known)

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

4922
8. Standard Industrial Classification (SIC) Code

486210
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, CO_2, NOx, SO_2, VOC, HAP, PM or Other [Specify])*	**Existing Facility-Wide Emission Cap(s) Per Consecutive 12-Month Time Period** (Tons)
N/A			

*CO = carbon monoxide, CO_2 = carbom dioxide, NOx = nitrogen oxides, SO_2 = sulfur dioxide, VOC = volatile organic compounds, HAP = hazardous air pollutant, PM = particulate matter, specify if "Other"

12. Will this proposed process 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. See the instructions for a link.

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:

   The proposed project includes the installation of one (1) Solar Taurus 60 natural gas turbine compressor unit (7,700 hp), a Waukesha VGF24GL natural gas fired emergency generator (585 hp), a fuel gas process heater (0.23 MMBtu/hr heat input), five fuel gas space heaters (0.072 MMBtu/hr heat input) a parts washer, new separator vessels and storage tanks and a gas cooler for the station.The new compressor turbine will be equipped with Solar's SoLoNOx technology to control emissions of NOx, CO and other air pollutants. Additionally, this application is including the operation of the existing metering and regulation (M&R) station as part of the facility.

Netting & Offsets

4. Is netting being used to avoid 310 CMR 7.00: Appendix A? ☐ Yes* ☒ No – Skip to 5

   *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.

Continue to Next Page ►

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 Emissions 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)

[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: Emission Offsets and Nonattainment Review).
[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: Emission Offsets and Nonattainment Review).
[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(s) below to summarize the details of each Emission Unit being proposed.

Table 3A

Facility-Assigned Identifying Number for Equipment (Emission Unit No.)	**Description of Equipment Including Manufacturer & Model Number or Equivalent** (e.g. Acme Coating Line, Model No. AB12)	**Air Contaminant(s) Emitted**	**Potential Emissions,**[1] **Uncontrolled** (Tons per Consecutive 12-Month Time Period)
EU2 ☒ New ☐ Modified	Gas Releases	PM[2]	N/A
		VOC	3.54
		CO_2	5.48
		Total HAPs	0.11
		Worst Case Individual HAP[1]	0.06
		Other: CO2 equivalent	3,836

[1] Potential emissions based on worst case raw material (e.g. coating) using maximum application rate and no air pollution control equipment. (See Section F. Record-Keeping Procedures.)
[2] 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 ($PM_{2.5}$).
[3] Calculate Worst Case Individual Hazardous Air Pollutant (HAP) potential emissions based on use of the raw material with the highest individual HAP content.

[1] Hexane(n-) emissions are presented for worst-case Individual HAP

B. Equipment Description (continued)

Table 3B			
Facility-Assigned Identifying Number for Equipment (Emission Unit No.)	**Description of Equipment Including Manufacturer & Model Number or Equivalent** (e.g. Acme Coating Line, Model No. AB12)	**Air Contaminant(s) Emitted**	**Potential Emissions, Uncontrolled** (Tons per Consecutive 12-Month Time Period)
EU3 ☒ New ☐ Modified	Fugitive Emissions from piping components	PM	NA
		VOC	2.21
		CO_2	1.1
		Total HAPs	0.16
		Worst Case Individual HAP[2]	0.07
		Other: CO2 equivalent	770

Note: If you are proposing more than three Emission Units, complete additional copies of these tables.

Table 3C			
Facility-Assigned Identifying Number for Equipment (Emission Unit No.)	**Description of Equipment Including Manufacturer & Model Number or Equivalent** (e.g. Acme Coating Line, Model No. AB12)	**Air Contaminant(s) Emitted**	**Potential Emissions, Uncontrolled** (Tons per Consecutive 12-Month Time Period)
☐ New ☐ Modified		PM	
		VOC	
		CO_2	
		Total HAPs	
		Worst Case Individual HAP	
		Other:	

7. Does your proposed project involve coating and/or printing operation(s)? ☐ Yes* ☒ No

*If Yes, complete and attach to this application Form BWP AQ Coatings & Inks.

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

*If Yes, complete Table 4 on the next page to summarize the details of each PCD being proposed.

[2] Xylene emissions are presented for worst-case Individual HAP

B. Equipment Description (continued)

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 4A

Facility-Assigned Identifying Number & Description of Air Pollution Control Device (PCD)	**Emission Unit No. Served by PCD**	**Air Contaminant(s) Controlled**	**Capture Efficiency (CE), Percent by Weight** (CE is Presumed to be 100% Based on Permanent Total Enclosure (PTE), 40 CFR 51 Appendix B Method 204)	**Destruction Efficiency (DE) or Removal Efficiency** (Percent by Weight)	**Overall Control** (Percent by Weight (CE*DE)/100)
Facility I.D. No.		PM[1]			
Description		VOC			
		Total HAPs			
☐ New		Individual HAP*			
☐ Existing		Other:			

[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 4B

Facility-Assigned Identifying Number & Description of Air Pollution Control Device (PCD)	**Emission Unit No. Served by PCD**	**Air Contaminant(s) Controlled**	**Capture Efficiency (CE)** (Percent by Weight; CE is Presumed to be 100% Based on Permanent Total Enclosure (PTE), 40 CFR 51 Appendix B Method 204)	**Destruction Efficiency (DE) or Removal Efficiency** (Percent by Weight)	**Overall Control** (Percent by Weight (CE*DE)/100)
Facility I.D. No.		PM			
Description		VOC			
		Total HAPs			
☐ New		Individual HAP			
☐ Existing		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

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

9. Complete the table 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).

Table 5			
Emission Unit No(s). Served by Noise Suppression Equipment	**Type of Noise Suppression Equipment** (e.g. Mufflers, Acoustical Enclosures)	**Equipment Manufacturer**	**Equipment Model No.**
N/A	N/A	N/A	N/A

Continue to Next Page ►

B. Equipment Description (continued)

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

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

*If No, explain:

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

No visible emissions from the proposed project will be expected due to the nature of operations and use of natural gas as fuel.

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

No odor impacts from the proposed project will be expected due to the nature of operations and use of natural gas as fuel.

C. Stack Description

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.

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

Table 6

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**
EU2[3]	N/A	N/A	N/A	N/A	N/A	N/A
EU3[3]	N/A	N/A	N/A	N/A	N/A	N/A

[3] EU2 and EU3 are fugitive emissions from gas releases and piping components and do not vent to a stack.

D. Best Available Control Technology (BACT) Emissions

1. Complete the table(s) below to summarize the proposed project's BACT emissions.

Table 7A

Emission Unit No.	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Grains per Actual Cubic Foot [gr/acf], Grains per Dry Standard Cubic Foot [gr/dscf], or Parts per Million on a Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, gr/acf, gr/dscf, or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions, if Any** (Tons) (Enter "N/A" if not requesting a long-term emissions cap)	**Proposed Monthly Time Period Emissions Restrictions[1]** (Tons) [4] (Enter "N/A" if not requesting a monthly emissions cap)	**Proposed Production or Operational Limits[2]** (Enter "N/A" if not requesting a production or operational limit)
EU2	PM[3]	N/A	N/A	N/A	N/A	N/A
	VOC	0.81 lb/hr	N/A	3.54	3.19	N/A
	Total HAPs	0.02 lb/hr	N/A	0.11	0.10	N/A
	Individual HAP[5]	0.01 lb/hr	N/A	0.06	0.05	N/A
	CO_2	1.25 lb/hr	N/A	5.48	4.93	N/A
	Other: CO2e	876 lb/hr	N/A	3,836	3,452	N/A

[1] Provide a monthly emission restriction if proposing a 12-month time period restriction.
[2] Provide a definitive method to monitor and document compliance with any emission(s) limit(s) to be contained in a written
MassDEP Approval. Production or operational limits are but one method that may be used. To foster pollution prevention,
you may propose other methods, subject to approval by MassDEP.
[3] 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 ($PM_{2.5}$).

[4] Proposed tons per month (tpm) emissions are the worst case emissions calculated for a month with 31 days of operation. The maximum volume of gas released in a month was calculated as the sum of monthly average gas release volume and maximum hourly gas release volume.
[5] Hexane(n-) emissions are presented for worst-case Individual HAP

D. Best Available Control Technology (BACT) Emissions (continued)

Table 7B

Emission Unit No.	Air Contaminant	Uncontrolled Emissions (lbs/hr, gr/acf, gr/dscf, or ppmvd@ %O_2 or CO_2)	Proposed BACT Emissions (lbs/hr, gr/acf, gr/dscf, or ppmvd@ %O_2 or CO_2)	Proposed Consecutive 12-Month Time Period Emissions, if Any (Tons)	Proposed Monthly Time Period Emissions Restrictions (Tons) [6]	Proposed Production or Operational Limits
EU3	PM	N/A	N/A	N/A	N/A	N/A
	VOC	See footnote below[7]	See footnote below[7]	2.21	0.41	N/A
	Total HAPs	0.12 lb/hr	0.04 lb/hr	0.16	0.02	N/A
	Individual HAP[8]	0.05 lb/hr	0.02 lb/hr	0.07	0.01	N/A
	CO_2	0.25 lb/hr	N/A	1.1	0.13	N/A
	Other: CO2 equivalent	175 lb/hr	N/A	770	66	N/A

Note: If you are proposing more than three Emission Units, complete additional copies of these tables.

Table 7C

Emission Unit No.	Air Contaminant	Uncontrolled Emissions (lbs/hr, gr/acf, gr/dscf, or ppmvd@ %O_2 or CO_2)	Proposed BACT Emissions (lbs/hr, gr/acf, gr/dscf, or ppmvd@ %O_2 or CO_2)	Proposed Consecutive 12-Month Time Period Emissions, if Any (Tons)	Proposed Monthly Time Period Emissions Restrictions (Tons)	Proposed Production or Operational Limits
	PM					
	VOC					
	Total HAPs					
	Individual HAP					
	CO_2					

[6] Proposed tons per month (tpm) emissions are the worst case emissions calculated for a month with 31 days of operation and maximum hourly emission rate (lb/hr) from Tables H-1Ba through H-1Bd included in Attachment G to the application report.
[7] Piping Components in natural gas service VOC – 0.16 lb/hr
Piping Components in pipeline liquids service VOC – 0.75 lb/hr uncontrolled and 0.22 lb/hr with LDAR (BACT)
Piping Components in oil service VOC – 0.12 lb/hr
Details are provided in Attachment G - Detailed Emission Calculations and Manufacturer Specifications.
[8] Xylene emissions are presented for worst-case Individual HAP

	Other:					

D. Best Available Control Technology (BACT) Emissions (continued)

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 previous table(s) Top-Case BACT as referenced in 310 CMR 7.02(8)(a)2.a? ☒ Yes ☐ No

3. Are proposed BACT emission limits established using the approach defined in 310 CMR 7.02(8)(a)2.b? ☒ Yes ☐ No

If you answered **Yes** to Question 3, provide details below:

Algonquin will maintain good operating practices, along with ESD preventative measures, as BACT for gas release events. More details are provided in Section 5.7 and 5.8 of the original application report. Algonquin proposes to develop an LDAR program consistent with the TCEQ 28 RCT control efficiencies for the piping components in pipeline liquid services at the Weymouth Compressor Station. More details are provided in Section 5.2 of the supplemental submittal.

If you answered **No** to both questions above, you must attach to this application a completed 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.

E. Monitoring Procedures

Complete the table below to summarize the details of the proposed project's monitoring procedures.

Table 8			
Emission Unit No.	**Type or Method of Monitoring** (e.g. CEMS[1], Flow Meter)	**Parameter/Emission Monitored**	**Frequency of Monitoring**
EU3	Hand-held monitor	VOC	Quarterly

[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, purchase records, raw material records, and CEMS records.

Table 9

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)
EU2	Emissions	Calculation of emissions	Monthly and 12-month rolling
EU3	Emissions	Calculation of emissions	Quarterly
EU3	Results of LDAR monitoring	Documentation of LDAR monitoring	Quarterly

Examples of emissions calculations for record keeping purposes:

- Worst case coating/ink/other contains 5.5 pounds of **VOC** per gallon of coating
- Process application rate = 3.0 gallons of coating/ink/other applied per hour
- Process operates 1,800 hours per consecutive 12-month time period

3.0 gallons per hour X 5.5 lbs of **VOC** per gallon X 1,800 hours per consecutive 12-month time period X 1 ton per 2,000 pounds = 14.8 tons of **VOC** per consecutive 12-month time period

-or-

- Worst case coating/ink/other contains 5.5 pounds of **VOC** per gallon of coating
- Process utilized 5,678 gallons of coating per consecutive 12-month time period

5,678 gallons per consecutive 12-month time period X 5.5 pounds **VOC** per gallon X 1 ton per 2,000 pounds = 15.6 tons of **VOC** per consecutive 12-month time period

Continue to Next Page ►

G. Additional Information Checklist

Note: For guidance and specific Top-Case BACT requirements, see the instructions.

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

☐ Equipment Manufacturer Specifications, including but not limited to Material Safety Data Sheets, Technical Data Composition Sheets, etc.

☐ Equipment Standard Operating Procedures

☐ Equipment Standard Maintenance Procedures, Including Cleaning Method & Frequency

☒ Calculations to Support This Plan Application

☐ Air pollution control device manufacturer specifications, if applicable

☐ Air pollution control device standard operating procedures, if applicable

☐ Air pollution control device standard maintenance procedures, if applicable

☐ Process flow diagram

☐ BWP AQ BACT Form, if not proposing Top-Case BACT

☐ 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.

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? Applicable emission limitation(s):

40 CFR 61: National Emission Standards for Hazardous Air Pollutants (NESHAPS) ☐ Yes ☒ No

If Yes: Which subpart? Applicable emission limitation(s):

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

CPA-PROCESS (BWP AQ 02 Non-Major, BWP AQ 03 Majo

Comprehensive Plan Application for Process Emission Unit(s)
For Process Equipment Emitting 10 Tons or More of an Air Contaminant per Consecutive 12-Month Time Period.

X266786
Transmittal Number

Facility ID (if known)

H. Other Regulatory Considerations (continued)

40 CFR 63: NESHAPS for Source Categories – Maximum Achievable (MACT) or Generally Available (GACT) Control Technology ☐ Yes ☒ No

If Yes: Which subpart? Applicable emission limitation(s):

301 CMR 11.00: Massachusetts Environmental Policy Act (MEPA)? ☐ Yes ☒ No

If Yes: EOEA No.:

Other Applicable Requirements? ☐ Yes ☒ No

If Yes: Specify:

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.

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.

Lynne P. Santos
P.E. Name (Type or Print)

Lynne P Santos
P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
REGISTERED
PROFESSIONAL ENGINEER

Continue to Certification by Responsible Official ▶

X266786
Transmittal Number

Facility ID (if known)

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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Responsible Official Signature

VP- Field Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/17/2018
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp

Continue to Energy Efficiency Evaluation Survey ▶

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

[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

ATTACHMENT C: SUPPLEMENTAL FORMS

BWP AQ BACT Forms
BWP AQ Sound Form

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.

X266786
Transmittal Number

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)
EU1	Dry Low-NOx (DLN) Combustion Technology (SoLoNOx)	9 ppm NOx @ 15% O2

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.

Continue to Next Page ►

B. Air Pollution Control Technology/Technique Options (continued)

Table 2

	Option 1:	**Option 2:**	**Option 3:**
Description of Available Air Pollution Control Technologies/Techniques	Selective Catalytic Reduction	Dry Low NOx Combustion (SoLoNOx)	Water Injection/Good Combustion Practices
Pollutant(s) Controlled[1] (e.g. PM, NO_x, CO, SO_2, VOC, HAP)	NOx	NOx	NOx
Potential Emissions Before Control (Pounds Per Hour, Pounds Per Million British Thermal Units, or Parts Per Million, Dry Volume Basis)	9 ppm[1]	9 ppm	N/A
Resulting Emissions After Control (Pounds Per Hour, Pounds Per Million Btu, or Parts Per Million, Dry Volume Basis)	3-9 ppm	9 ppm	N/A
Annualized Cost in U.S. Dollars Per Ton of Pollutant Removed[2]	43,805 [2]	N/A	N/A

[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.

Continue to Next Page ►

[1] Selective Catalyst Reduction (SCR) control is assumed on top of $SoLoNO_X$ on Solar turbine. Algonquin and Solar Turbines believe that $SoLoNO_X$ is not an add-on control device, but rather it is a type of combustion chamber design that is integral to the design of the entire turbine.
[2] The annual NO_X PTE has been revised from 9.96 tpy to 10.03 tpy due to the change in estimated emissions for SU/SD. This slight increase is inconsequential to the results of the economic analysis. Therefore, these numbers have not been revised.

C. Annualized Cost Analysis[3]

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 3			
	Option 1	**Option 2**	**Option 3**
Total Capital Investment (TCI)			
Direct Purchase Cost			
1. Primary Control Device & Auxiliary Equipment	$574,100	$	$
2. Fans	$	$	$
3. Ducts	$	$	$
4. Other – Specify:	$	$	$
5. Instrumentation/Controls	$57,410	$	$
Indirect Capital Cost			
6. Construction	$354,544	$	$
7. Labor	$	$	$
8. Sales Taxes	$22,964	$	$
9. Freight Charges	$28,705	$	$
Engineering/Planning			
10. Contracting Fees	$207,545	$	$
11. Testing	$	$	$
12. Supervision	$186,790	$	$
13. Total Capital Investment (Add 1 Through 12)	$1,432,058	$	$
14. Annualized Capital Cost: $C[i(1+i)^n]/[(1+i)^n - 1]$*	$135,176	$	$

[3] The annual NO_X PTE has been revised from 9.96 tpy to 10.03 tpy due to the change in estimated emissions for SU/SD. This slight increase is inconsequential to the results of the economic analysis. Therefore, these numbers have not been revised.

* 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 3 (Continued)			
	Option 1	**Option 2**	**Option 3**
Annual Operating & Maintenance Costs			
Direct Operating Cost			
15. Labor	$18,889	$	$
16. Maintenance	$16,425	$	$
17. Replacement Parts	$16,425	$	$
Indirect Cost			
18. Property Taxes*	$0	$	$
19. Insurance	$0	$	$
20. Fees	$0	$	$
21. Total Annual Operating Costs (Add 15 Through 20)	$51,739	$	$
Energy Cost			
22. Annual Electrical Energy Expense	$95,997	$	$
23. Annual Auxiliary Fuel Cost	$99,212	$	$
24. Total Annual Energy Cost (Add 22 and 23)	$	$	$
25. Annual Waste Treatment & Disposal Costs	$10,532	$	$
26. Miscellaneous Annual Expenses	$	$	$
27. Annual Resource Recovery & Resale	$	$	$
28. Total Annualized Control Costs (14+21+24+25+26) - 27	$392,656	$	$
29. Amount of Pollutant Controlled Over Baseline Emissions** (Tons Per Year)	8.96 tpy		
30. Cost of Control (Dollars Per Ton) (Divide 28 By 29)	$43,805	$	$

*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]**
EM/SCONOx Technology	It is designed to operate effectively at temp between 300 to 700 F. The turbine's exhaust temperature is 950 F.
Selective Non-Catalytic Reduction (SNCR)	The temperature for operation is above the exhaust temp of turbine. It has never been applied on a turbine of this size.
Selective Catalytic Reduction (SCR)	The economic cost per ton of NOx removed exceeds the MassDEP guideline for non-attainment pollutants of $11,000 to $13,000 per ton.
Water Injection	Results in lower control efficiency than the proposed BACT

[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.

Lynne P. Santos
P.E. Name (Type or Print)

Lynne P. Santos
P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
REGISTERED
PROFESSIONAL ENGINEER

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

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.

X266786
Transmittal Number

Facility ID (if known)

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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Thomas V. Wooden
Responsible Official Signature

VP-Field Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/19/2018
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp.

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

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.

X266786
Transmittal Number

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)
EU1	Oxidation Catalyst	1.25 ppmvd CO at 15% O_2 or 0.20 lb/hr for CO
EU1	Oxidation Catalyst	0.25 lb/hr for VOC

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.

Continue to Next Page ►

B. Air Pollution Control Technology/Technique Options (continued)

Table 2			
	Option 1:	**Option 2:**	**Option 3:**
Description of Available Air Pollution Control Technologies/Techniques	Oxidation Catalyst	Good Combustion Practices	
Pollutant(s) Controlled[1] (e.g. PM, NO_x, CO, SO_2, VOC, HAP)	CO, VOC	CO, VOC	
Potential Emissions Before Control (Pounds Per Hour, Pounds Per Million British Thermal Units, or Parts Per Million, Dry Volume Basis)	25 ppmvd CO at 15% O_2 or 4.02 lb/hr for CO And 0.50 lb/hr for VOC	N/A	
Resulting Emissions After Control (Pounds Per Hour, Pounds Per Million Btu, or Parts Per Million, Dry Volume Basis)	1.25 ppmvd CO at 15% O_2 or 0.20 lb/hr for CO And 0.25 lb/hr for VOC	N/A	
Annualized Cost in U.S. Dollars Per Ton of Pollutant Removed[2]	N/A	N/A	

[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.

Continue to Next Page ►

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

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.

X266786
Transmittal Number

Facility ID (if known)

C. Annualized Cost Analysis - **Note: The chosen BACT is the top technically feasible control option as determined through the Top-Down BACT analysis for CO and VOC emissions and hence a cost analysis was not performed.**

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 3			
	Option 1	**Option 2**	**Option 3**
Total Capital Investment (TCI)			
Direct Purchase Cost			
1. Primary Control Device & Auxiliary Equipment	$	$	$
2. Fans	$	$	$
3. Ducts	$	$	$
4. Other – Specify:	$	$	$
5. Instrumentation/Controls	$	$	$
Indirect Capital Cost			
6. Construction	$	$	$
7. Labor	$	$	$
8. Sales Taxes	$	$	$
9. Freight Charges	$	$	$
Engineering/Planning			
10. Contracting Fees	$	$	$
11. Testing	$	$	$
12. Supervision	$	$	$
13. Total Capital Investment (Add 1 Through 12)	$	$	$
14. Annualized Capital Cost: $C[i(1+i)^n]/[(1+i)^n - 1]$*	$	$	$

* 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) **Note: The chosen BACT is the top technically feasible control option as determined through the Top-Down BACT analysis for CO and VOC emissions and hence a cost analysis was not performed.**

Table 3 (Continued)			
	Option 1	**Option 2**	**Option 3**
Annual Operating & Maintenance Costs			
Direct Operating Cost			
15. Labor	$	$	$
16. Maintenance	$	$	$
17. Replacement Parts	$	$	$
Indirect Cost			
18. Property Taxes*	$	$	$
19. Insurance	$	$	$
20. Fees	$	$	$
21. Total Annual Operating Costs (Add 15 Through 20)	$	$	$
Energy Cost			
22. Annual Electrical Energy Expense	$	$	$
23. Annual Auxiliary Fuel Cost	$	$	$
24. Total Annual Energy Cost (Add 22 and 23)	$	$	$
25. Annual Waste Treatment & Disposal Costs	$	$	$
26. Miscellaneous Annual Expenses	$	$	$
27. Annual Resource Recovery & Resale	$	$	$
28. Total Annualized Control Costs (14+21+24+25+26) - 27	$	$	$
29. Amount of Pollutant Controlled Over Baseline Emissions** (Tons Per Year)			

30. Cost of Control (Dollars Per Ton) (Divide 28 By 29)	$	$	$

*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 - Note: The chosen BACT is the top technically feasible control option as determined through the Top-Down BACT analysis for CO and VOC emissions and hence a feasibility analysis was not performed.

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]

[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.

Lynne P. Santos
P.E. Name (Type or Print)

Lynne P Santos
P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Thomas V. Wooden Jr.
Responsible Official Signature

VP-Field Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/19/2018
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp

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.

X266786
Transmittal Number

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)**
EU1	use of pipeline quality natural gas and good combustion and operating practices	0.0066 lb/MMBtu for $PM/PM_{10}/PM_{2.5}$
EU1	use of pipeline quality natural gas and good combustion and operating practices	14.29 lb/MMscf for SO_2 (based on 5 grains per 100 scf NG)

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.

Continue to Next Page ►

B. Air Pollution Control Technology/Technique Options (continued)

Table 2			
	Option 1:	**Option 2:**	**Option 3:**
Description of Available Air Pollution Control Technologies/Techniques	Clean fuel selection	Good Combustion Practices	
Pollutant(s) Controlled[1] (e.g. PM, NO_x, CO, SO_2, VOC, HAP)	$PM/PM_{10}/PM_{2.5}/SO_2$	$PM/PM_{10}/PM_{2.5}/SO_2$	
Potential Emissions Before Control (Pounds Per Hour, Pounds Per Million British Thermal Units, or Parts Per Million, Dry Volume Basis)	N/A	N/A	
Resulting Emissions After Control (Pounds Per Hour, Pounds Per Million Btu, or Parts Per Million, Dry Volume Basis)	0.0066 lb/MMBtu for $PM/PM_{10}/PM_{2.5}$ 14.29 lb/MMscf for SO_2 (based on 5 grains per 100 scf NG)		
Annualized Cost in U.S. Dollars Per Ton of Pollutant Removed[2]	N/A	N/A	

[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.

Continue to Next Page ►

C. Annualized Cost Analysis - **Note: The chosen BACT is the top technically feasible control option as determined through the Top-Down BACT analysis for CO and VOC emissions and hence a cost analysis was not performed.**

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 3			
	Option 1	**Option 2**	**Option 3**
Total Capital Investment (TCI)			
Direct Purchase Cost			
1. Primary Control Device & Auxiliary Equipment	$	$	$
2. Fans	$	$	$
3. Ducts	$	$	$
4. Other – Specify:	$	$	$
5. Instrumentation/Controls	$	$	$
Indirect Capital Cost			
6. Construction	$	$	$
7. Labor	$	$	$
8. Sales Taxes	$	$	$
9. Freight Charges	$	$	$
Engineering/Planning			
10. Contracting Fees	$	$	$
11. Testing	$	$	$
12. Supervision	$	$	$
13. Total Capital Investment (Add 1 Through 12)	$	$	$
14. Annualized Capital Cost: $C[i(1+i)^n]/[(1+i)^n - 1]$*	$	$	$

* 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) **Note: The chosen BACT is the top technically feasible control option as determined through the Top-Down BACT analysis for CO and VOC emissions and hence a cost analysis was not performed.**

Table 3 (Continued)			
	Option 1	**Option 2**	**Option 3**
Annual Operating & Maintenance Costs			
Direct Operating Cost			
15. Labor	$	$	$
16. Maintenance	$	$	$
17. Replacement Parts	$	$	$
Indirect Cost			
18. Property Taxes*	$	$	$
19. Insurance	$	$	$
20. Fees	$	$	$
21. Total Annual Operating Costs (Add 15 Through 20)	$	$	$
Energy Cost			
22. Annual Electrical Energy Expense	$	$	$
23. Annual Auxiliary Fuel Cost	$	$	$
24. Total Annual Energy Cost (Add 22 and 23)	$	$	$
25. Annual Waste Treatment & Disposal Costs	$	$	$
26. Miscellaneous Annual Expenses	$	$	$
27. Annual Resource Recovery & Resale	$	$	$
28. Total Annualized Control Costs (14+21+24+25+26) - 27	$	$	$
29. Amount of Pollutant Controlled Over Baseline Emissions** (Tons Per Year)			

30. Cost of Control (Dollars Per Ton) (Divide 28 By 29)	$	$	$

*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 - **Note: The chosen BACT is the top technically feasible control option as determined through the Top-Down BACT analysis for PM and SO_2 emissions and hence a feasibility analysis was not performed.**

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]

[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.

Lynne P. Santos
P.E. Name (Type or Print)

Lynne P. Santos
P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
REGISTERED
PROFESSIONAL ENGINEER

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.

X266786
Transmittal Number

Facility ID (if known)

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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Thomas V. Wooden
Responsible Official Signature

VP-Field Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/17/2018
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp

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.

X266786
Transmittal Number

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)**
EU1	Fuel selection and good combustion/ operating practices	35,800 tons CO_2e/year

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.

Continue to Next Page ►

B. Air Pollution Control Technology/Technique Options (continued)

Table 2

	Option 1:	**Option 2:**	**Option 3:**	**Option 4:**
Description of Available Air Pollution Control Technologies/Techniques	Carbon Capture and Storage (CCS)	Fuel Selection	High Efficiency Turbine	Good Combustion Practices
Pollutant(s) Controlled[1] (e.g. PM, NO_x, CO, SO_2, VOC, HAP)	CO_2	CO_2	CO_2	CO_2
Potential Emissions Before Control (Pounds Per Hour, Pounds Per Million British Thermal Units, or Parts Per Million, Dry Volume Basis)	35,800 tpy CO_2	35,568 tpy CO_2	35,568 tpy CO_2	35,568 tpy CO_2
Resulting Emissions After Control (Pounds Per Hour, Pounds Per Million Btu, or Parts Per Million, Dry Volume Basis)	90% control efficiency	N/A	N/A	N/A
Annualized Cost in U.S. Dollars Per Ton of Pollutant Removed[2]	$709/ ton of CO_2 captured	N/A	N/A	N/A

[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.

Continue to Next Page ►

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.

X266786
Transmittal Number

Facility ID (if known)

C. Annualized Cost Analysis – Please see detailed calculations attached in Attachment E

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 3			
	Option 1	**Option 2**	**Option 3**
Total Capital Investment (TCI)			
Direct Purchase Cost			
1. Primary Control Device & Auxiliary Equipment	$	$	$
2. Fans	$	$	$
3. Ducts	$	$	$
4. Other – Specify:	$	$	$
5. Instrumentation/Controls	$	$	$
Indirect Capital Cost			
6. Construction	$	$	$
7. Labor	$	$	$
8. Sales Taxes	$	$	$
9. Freight Charges	$	$	$
Engineering/Planning			
10. Contracting Fees	$	$	$
11. Testing	$	$	$
12. Supervision	$	$	$
13. Total Capital Investment (Add 1 Through 12)	$	$	$
14. Annualized Capital Cost: $C[i(1+i)^n]/[(1+i)^n - 1]$*	$	$	$

* 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) - Please see detailed calculations attached in Attachment E

Table 3 (Continued)			
	Option 1	**Option 2**	**Option 3**
Annual Operating & Maintenance Costs			
Direct Operating Cost			
15. Labor	$	$	$
16. Maintenance	$	$	$
17. Replacement Parts	$	$	$
Indirect Cost			
18. Property Taxes*	$	$	$
19. Insurance	$	$	$
20. Fees	$	$	$
21. Total Annual Operating Costs (Add 15 Through 20)	$	$	$
Energy Cost			
22. Annual Electrical Energy Expense	$	$	$
23. Annual Auxiliary Fuel Cost	$	$	$
24. Total Annual Energy Cost (Add 22 and 23)	$	$	$
25. Annual Waste Treatment & Disposal Costs	$	$	$
26. Miscellaneous Annual Expenses	$	$	$
27. Annual Resource Recovery & Resale	$	$	$
28. Total Annualized Control Costs (14+21+24+25+26) - 27	$	$	$
29. Amount of Pollutant Controlled Over Baseline Emissions** (Tons Per Year)	$		
30. Cost of Control (Dollars Per Ton) (Divide 28 By 29)	$	$	$

*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]
Carbon Capture and Sequestration (CCS)	The economic cost per ton of CO2 captured is infeasible and as such CCS is considered to be cost ineffective for the project

[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.

Lynne P. Santos
P.E. Name (Type or Print)

P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
REGISTERED
PROFESSIONAL ENGINEER

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

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.

X266786
Transmittal Number

Facility ID (if known)

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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Thomas V. Wooden
Responsible Official Signature

VP-Field Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/17/2018
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp

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

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.

X266786
Transmittal Number

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.

Significant sound sources include: 1) noise generated by the turbine/compressor that penetrates the compressor building, 2) turbine exhaust noise (primary noise source that could generate perceptible vibration, 3) noise radiated from aboveground gas piping and related piping components, 4) noise of the outdoor lube oil cooler and outdoor gas cooler, 5) noise generated by the turbine air intake system. The project will use a sound suppressant muffler system for the turbine exhaust system, acoustical pipe insulation for outdoor above ground gas piping, a silencer for each turbine air intake system, a low-noise lube oil cooler for each compressor unit, and a low-noise gas cooler.

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. [Note 1]

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.

[1] See attached report: Hoover & Keith, Inc. (H&K), *Weymouth Compressor Station (Norfolk County, Massachusetts) Results of the most Recent Ambient Sound Survey and Updated Acoustical Analysis of a New Natural Gas Compressor Station Associated with the Proposed Atlantic Bridge Project ("AB Project)*, September 3, 2015.

.

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: **Note – measurements were taken at nearest residence to site.**

A-Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND

ND = No Data

E. Full Octave Band Analysis (continued)

b. At the nearest inhabited building and if applicable at buildings at higher elevation: **[Note 2]**

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
44.8	57.6	56.4	51.0	43.1	39.7	36.9	40.0	30.1	19.5	ND

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.

a. At property line:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

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
NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

NA = Not Applicable
[Note 2] H&K Report, Table 6, Pos. 1 (NSA #1)

Continue to Next Page ►

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

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.

X266786
Transmittal Number

Facility ID (if known)

E. Full Octave Band Analysis (continued)

3. **Expected** neighborhood sound pressure levels after installation of sound abatement equipment.

a. At property line: **Note – measurements were taken at nearest residence to site**

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
ND	ND	ND	ND	ND	ND	ND	ND	ND	ND	ND

b. At nearest inhabited building and if applicable at buildings at higher elevations: **[Note 3]**

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
46.9	63	57	51	43	37	37	34	27	17	ND

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.

[Note 3] H&K Report, Table 7.

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.

Lynne P. Santos
P.E. Name (Type or Print)

Lynne P. Santos
P.E. Signature

Managing Consultant
Position/Title

Trinity Consultants
Company

05/14/2018
Date (MM/DD/YYYY)

47225
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
LYNNE P. SANTOS
ENVIRONMENTAL
No. 47225
REGISTERED
PROFESSIONAL ENGINEER

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

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.

X266786
Transmittal Number

Facility ID (if known)

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.

Thomas V. Wooden Jr.
Responsible Official Name (Type or Print)

Responsible Official Signature

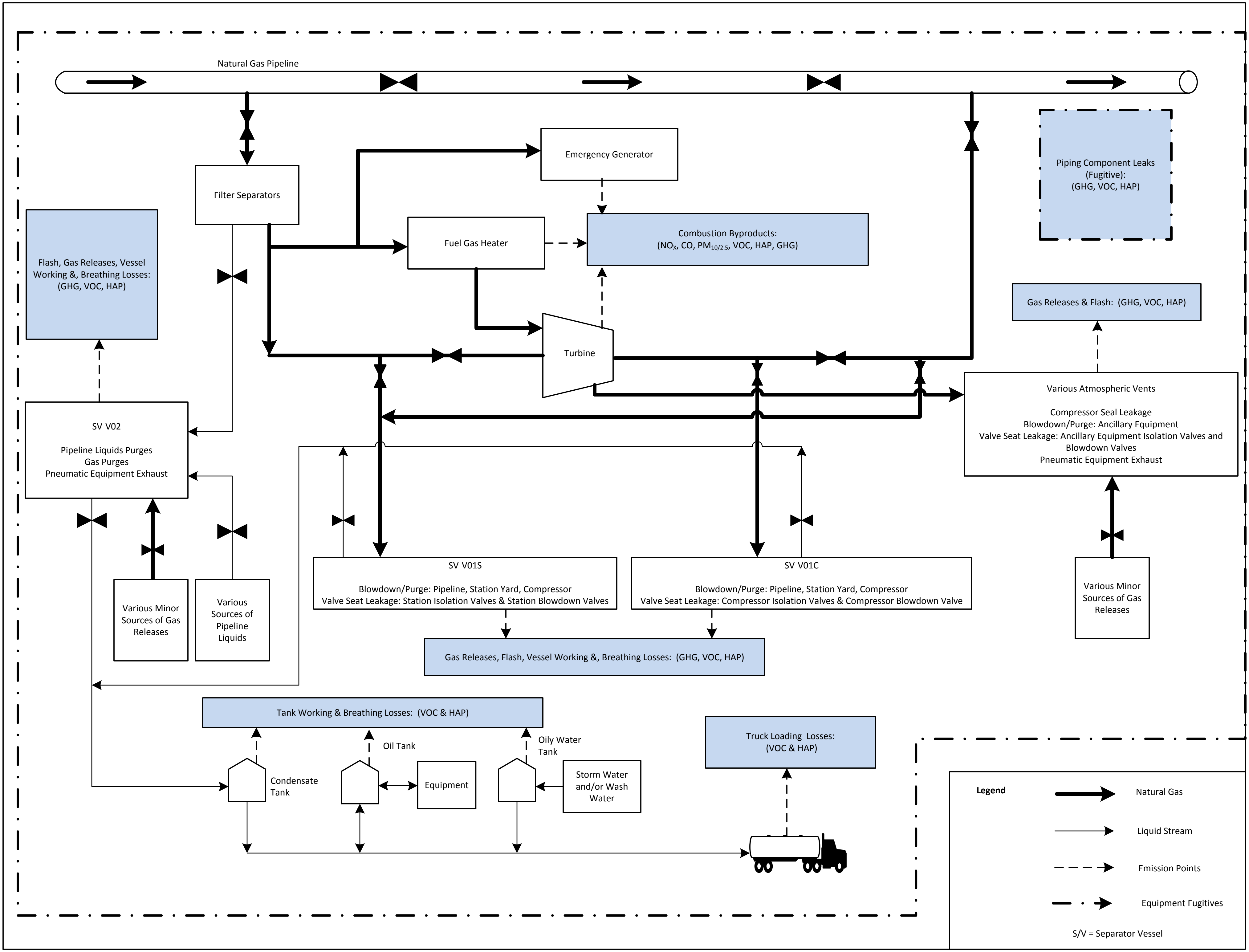
VP Operations
Responsible Official Title

Algonquin Gas Transmission, LLC
Responsible Official Company/Organization Name

05/17/2018
Date (MM/DD/YYYY)

This Space Reserved for MassDEP Approval Stamp

ATTACHMENT D: FIGURES


Natural Gas Pipeline
Filter Separators
Emergency Generator
Fuel Gas Heater
Combustion Byproducts:
(NO_X, CO, $PM_{10/2.5}$, VOC, HAP, GHG)
Piping Component Leaks
(Fugitive):
(GHG, VOC, HAP)
Flash, Gas Releases, Vessel Working &, Breathing Losses:
(GHG, VOC, HAP)
Turbine
Gas Releases & Flash: (GHG, VOC, HAP)
Various Atmospheric Vents
Compressor Seal Leakage
Blowdown/Purge: Ancillary Equipment
Valve Seat Leakage: Ancillary Equipment Isolation Valves and Blowdown Valves
Pneumatic Equipment Exhaust
SV-V02
Pipeline Liquids Purges
Gas Purges
Pneumatic Equipment Exhaust
Various Minor Sources of Gas Releases
Various Sources of Pipeline Liquids
SV-V01S
Blowdown/Purge: Pipeline, Station Yard, Compressor
Valve Seat Leakage: Station Isolation Valves & Station Blowdown Valves
SV-V01C
Blowdown/Purge: Pipeline, Station Yard, Compressor
Valve Seat Leakage: Compressor Isolation Valves & Compressor Blowdown Valve
Various Minor Sources of Gas Releases
Gas Releases, Flash, Vessel Working &, Breathing Losses: (GHG, VOC, HAP)
Tank Working & Breathing Losses: (VOC & HAP)
Truck Loading Losses:
(VOC & HAP)
Condensate Tank
Oil Tank
Equipment
Oily Water Tank
Storm Water and/or Wash Water
Legend
Natural Gas
Liquid Stream
Emission Points
Equipment Fugitives
S/V = Separator Vessel

DWG. NO.	REFERENCE DWG.	REV	DSN	CK	DESCRIPTION

BASIC SYSTEMS
BASIC SYSTEMS, INC.
CAMBRIDGE, OHIO U.S.A.
(740) 432-2001

ENGINEERING APPROVALS	BID		CONSTRUCTION	
DRAWN BY: DAJ				
DRAFTING SUPERVISOR				
DESIGN ENGINEER				
DESIGN MANAGER				
TITLE	SIGNATURE	DATE	SIGNATURE	DATE

AIR PERMIT PLAN

LOC. WEYMOUTH, MASSACHUSETTS

Spectra Energy Partners.

Algonquin Gas Transmission, LLC
5400 Westheimer Ct. Houston, TX 77056-5310 713 / 627-5400

YEAR: 2017	W.O.CE.000089.005	SCALE: 1" = 40'	DWG. WEYM-A-0020	REV. 4

IG.# WEYM0020.16

ATTACHMENT E: BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Summary Tables of BACT Determinations
Detailed Cost Calculations

PRELIMINARY COST ESTIMATE:
SCR/CO CATALYST SYSTEMS
FOR THREE SOLAR ENGINES
(Mars 100, Mars 90, Taurus 60)

Prepared for

Solar Turbines, Inc.
Houston, Texas

Prepared by

Fossil Energy Research Corporation
Laguna Hills, California

October 2013

FERCo
Fossil Energy Research Corp.
23342-C South Pointe Drive, Laguna Hills, California 92653
Telephone: (949) 859-4466 Fax: (949) 859-7916

1. Background

FERCo is proposing a unique approach for the Solar SCR/CO catalyst systems. Traditionally, the CO/SCR systems are set up such that after leaving the gas turbine the following takes place (see Figure 1):

- Tempering air is added to reduce the temperature conducive with the catalyst requirements
- The flue gas is expanded to reduce the velocity to the range of 15 – 20 ft/sec
- The flue gas flows through the CO catalyst
- Ammonia is added at the AIG
- The flue gas/ammonia mixture flows through the SCR catalyst

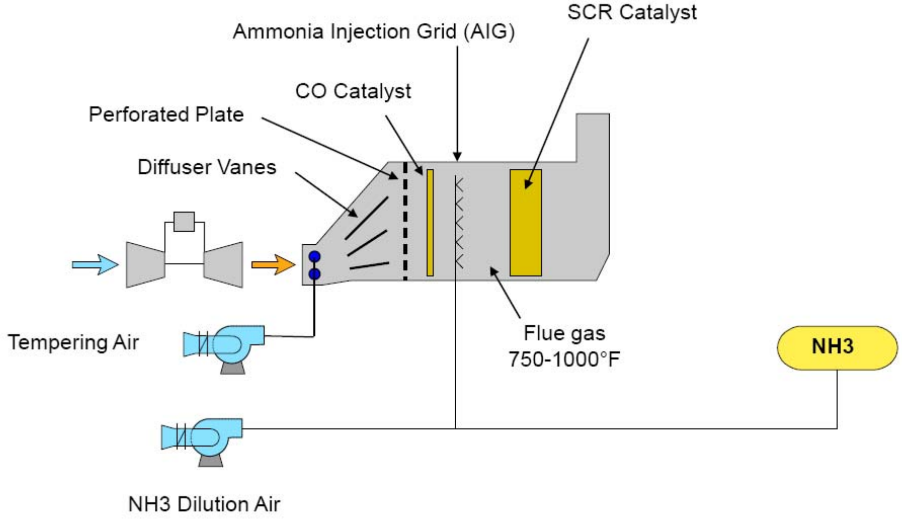


Figure 1. Traditional Simple Cycle CO/SCR Catalyst Arrangement

This configuration and sequence is traditionally used because ammonia should not be injected ahead of the CO catalyst, as the CO catalyst will oxidize some of the ammonia to NO_x. This means that the AIG must be located between the CO catalyst and the SCR catalyst within a large cross section with low velocity. Thus, the AIG consists of many injection lances to allow for adequate distribution and requires sufficient space between the AIG and SCR catalyst to allow the ammonia to mix with the flue gas.

2. Proposed Approach

FERCo is proposing a different arrangement for these Solar engines. Haldor-Topsoe has just introduced a new CO catalyst that is intended to be located downstream of the SCR catalyst. With this arrangement, the ammonia injection can be moved further upstream and injected into the high velocity flue gas stream exiting the engine. FERCo has previously done this arrangement on two small Solar engines installed at St. Agnes hospital in Fresno, CA (this system only had SCR catalyst). In this high velocity stream it is easier to mix the ammonia with the flue gas. Also, space for mixing is not needed in the main reactor so the reactor can be much smaller. This proposed approach is shown in Figure 2.

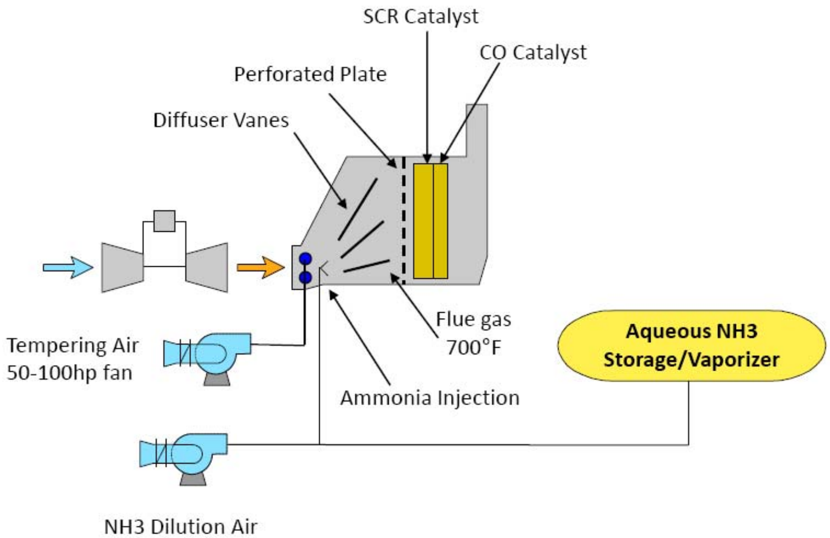


Figure 2. Proposed Arrangement (CO Catalyst Downstream of the SCR Catalyst)

3. Estimated Budgetary Costs

In preparing this budgetary estimate, the following was assumed:

- Inlet NO_x: 15 ppm
- NO_x reduction: 90%
- NH_3 slip: 5 ppm
- CO oxidation: 95%
- CO catalyst located downstream of the SCR catalyst
- Dilution/tempering air added to reduce the temperature of the flue gas to 750°F
- The reagent was assumed to be 19 wt % aqueous ammonia
- The aqueous ammonia was pre-vaporized and injected close to the gas turbine exit
- The systems for the Mars 100 and Mars 90 are identical

Table 2 provides the ballpark cost estimate for these systems. It should be noted that the engineering costs for either the Mars 100 or Mars 90 will in actuality be smaller than included, since both systems are identical.

Detailed Scope:

Reagent System
- Tanks (plastic but can be stainless steel), approximately 1000 gallons for each of the Mars turbines, and 500 gal for the Taurus
- Electric vaporizers
- Forwarding pumps
- Transfer skid
- AIG

SCR and CO Catalyst
- Purchased from Haldor Topsoe

Reactor/Ductwork/Stack
- Material is carbon steel
- Includes diffuser vanes and perforated plate

Controls
- PLC and operator interface

Dilution Air Fans
- 100 HP for the Mars turbines, 75 HP for the Taurus

Cold Flow Model
- Build and test scale model of the turbines to design diffuser vanes and AIG

CEMS
- NOx, O2 and CO

Other Instrumentation
- Inlet NOx/O2 monitor for NH3 control
- Thermocouples to monitor reactor temperature

Engineering
- Unit design interacting with vendors to purchase all of the material

Installation (can be done by others)
- labor that will be associated with putting all of the pieces together on site
- mating the reactor and stack with the gas turbine
- any foundation work that needs to be done
- installing the catalyst
- installing the reagent system

Startup/Optimization
- Startup
- Tuning the ammonia injection system
- Tuning the SCR control system
- Verifying the NOx reduction performance and ammonia slip

Not Included in Scope:

- Foundations for reactor and stack
- Power panel for motors and vaporizers

Table 1 Estimated Utilities

		Mars 100	Mars 90	Taurus 60
Flue Gas Flow	lb/hr	43	40	30
NOx-in	ppm	15	15	15
NOx Reduction	%	90	90	90
CO Reduction	%	95	95	95
Aqueous NH3 Flow(a)	lb/hr	19	16	9
SCR/CO Catalyst Vol.	m^3	8	8	4.2
SCR/CO Cat Depth	mm	460	460	460
Reactor Cross section	ft x ft	12ft x 15 ft	12ft x 15 ft	9 ft x 10.5 ft
Dilution Air	HP	100	100	75
Flow/Press	lb/hr/"H2O	95,800/21	95,800/21	61,100/22

Table 2 Estimated Budgetary Costs

	Mars 100		Mars 90		Taurus 60	
Equipment (w/CEMS)	$	1,873,100	$	1,786,600	$	1,673,100
CEMS Only	$	375,000	$	375,000	$	375,000
Commissioning	$	625,000	$	625,000	$	625,000

Table 3 Estimated Budgetary Cost Allocations

	Mars 100		Mars 90		Taurus 60	
CO Catalyst Cost Allocation	$	841,300	$	798,100	$	724,000
SCR Catalyst Cost Allocation	$	1,031,800	$	988,500	$	949,100

RBLC Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines - NOx Control

RBLC ID	Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Column8	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	SOLAR MARS 90 TURBINE	NATURAL GAS	11.86	MW	Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTION TECHNOLOGY (SOLONOX)	28.4	LB/H	85	PPMV
*AK-0083	KENAI NITROGEN OPERATIONS	AK	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBtu/hr	Nitrogen Oxides (NOx)	Selective Catalytic Reduction	7	PPMV	0	
AL-0208	EXXON MOBILE BAY -- NORTHWEST GULF FIELD	AL	TURBINE, SIMPLE CYCLE	NATURAL GAS	6000	bhp	Nitrogen Oxides (NOx)	SOLONOX COMBUSTOR	25	PPM @ 15%O2	0	
AL-0209	EXXON MOBILE -- MOBILE BAY - BON SECURE BAY FIELD	AL	TURBINE, SIMPLE CYCLE	NATURAL GAS	3600	bhp	Nitrogen Oxides (NOx)	SOLONOX COMBUSTION	25	PPM @ 15% O2	0	
CA-1174	EL CAJON ENERGY LLC	CA	Gas turbine simple cycle	Natural gas	49.95	MW	Nitrogen Oxides (NOx)	Water injection and SCR	2.5	PPMV	0	
CA-1175	ESCONDIDO ENERGY CENTER LLC	CA	Gas turbine simple cycle	Natural gas	46.5	MW	Nitrogen Oxides (NOx)	SCR water injection	2.5	PPMV@15% OXYGEN	0	
CA-1176	ORANGE GROVE PROJECT	CA	Gas turbine simple cycle	Natural gas	49.8	MW	Nitrogen Oxides (NOx)	SCR water injection	2.5	PPM	0	
*CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	Three simple cycle combustion turbines	natural gas	799.7	mmbtu/hr	Nitrogen Oxides (NOx)	Good combustor design, Water Injection and Selective Catalytic Reduction (SCR)	5	PPMVD AT 15% O2	15.5	LB/HR
*CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	Turbines - two simple cycle gas	natural gas	799.7	mmbtu/hr each	Nitrogen Oxides (NOx)	SCR and dry low NOx burners	23	LB/HR	0	
CO-0059	CHEYENNE STATION	CO	PHASE II TURBINE	NATURAL GAS	71.42	MMBTU/H	Nitrogen Oxides (NOx)	SOLONOX II (DRY LOW NOX).	15	PPM @ 15% O2	0	
FL-0266	PAYNE CREEK GENERATING STATION/SEMINOLE ELECTRIC	FL	SIMPLE CYCLE COMBUSTION TURBINES	NATURAL GAS	30	MW	Nitrogen Oxides (NOx)	WATER INJECTION AND LOW OPERATING HOURS	20	PPM	42	PPM
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	LA	GAS TURBINE GENERATOR NOS. 1-4	LNG	30	MW EA.	Nitrogen Oxides (NOx)	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	29	LB/H	118.79	T/YR
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Refrigeration Compressor Turbines (16)	Natural Gas	286	MMBTU/H	Nitrogen Oxides (NOx)	water injection	22.94	LB/H	0	
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Generation Turbines (2)	Natural Gas	286	MMBTU/H	Nitrogen Oxides (NOx)	water injection	28.68	LB/H	0	
LA-0232	STERLINGTON COMPRESSOR STATION	LA	COMPRESSOR TURBINE NO. 1	NATURAL GAS	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	19.72	T/YR
LA-0232	STERLINGTON COMPRESSOR STATION	LA	COMPRESSOR TURBINE NO. 2	NATURAL GAS	79.1	MMBTU/H	Nitrogen Oxides (NOx)	DRY LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES	0.057	LB/MMBTU	19.72	T/YR
MD-0035	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	21.7	MW	Nitrogen Oxides (NOx)	DRY LOW-NOX COMBUSTORS AND SCR	2.5	PPMVD	1	LB/MW-H
MD-0036	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	12.2	MW	Nitrogen Oxides (NOx)	EXCLUSIVE USE OF LNG QUALITY, LOW SULFUR NATURAL GAS; LNB AND SCR	5	PPMVD	1.2	LB/MW-H
*MI-0410	THETFORD GENERATING STATION	MI	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Nitrogen Oxides (NOx)	Dry low-NOx combustors	0.09	LB/MMBTU	0	
*ND-0029	PIONEER GENERATING STATION	ND	Natural gas-fired turbines	Natural gas	451	MMBtu/hr	Nitrogen Oxides (NOx)	Water injection plus SCR	5	PPPMVD	19	LB
*ND-0030	LONESOME CREEK GENERATING STATION	ND	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBtu/hr	Nitrogen Oxides (NOx)	SCR	5	PPMVD	18.5	LB
NJ-0075	BAYONNE ENERGY CENTER	NJ	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	NATURAL GAS	603	MMBTU/H	Nitrogen Oxides (NOx)	SELECTIVE CATALYTIC REDUCTION SYSTEM (SCR) AND WET LOW-EMISSION (WLE) COMBUSTORS SUBJECT TO LAER	2.5	PPMVD@15%O2	0.0092	LB/MMBTU
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	NJ	SIMPLE CYCLE TURBINE	Natural Gas	8940000	MMBtu/yr for six turbines combined	Nitrogen Oxides (NOx)	SCR and Use of Clean Burning Fuel: Natural gas	2.5	PPMVD@15%O2	4.39	LB/H
NJ-0077	HOWARD DOWN STATION	NJ	SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(>25 MW)	NATURAL GAS	590	MMBtu/hr	Nitrogen Oxides (NOx)	THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR) TO CONTROL NOX EMISSION AND USE CLEAN FUELS NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL TO MINIMIZE NOX EMISSIONS	2.5	PPMVD@15%O2	5.4	LB/H
NM-0051	CUNNINGHAM POWER PLANT	NM	Normal Mode (without Power Augmentation)	natural gas			Nitrogen Dioxide (NO2)	Dry Low NOx Burners Type K & Good Combustion Practice	21	PPMVD	0	
NM-0051	CUNNINGHAM POWER PLANT	NM	Power Augmentation	natural gas			Nitrogen Dioxide (NO2)	Dry Low NOx burners, Type K. Good Combustion Practices as defined in the permit.	30	PPMVD	0	
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS	97.81	MMBTU/H	Nitrogen Oxides (NOx)	THE SOLONOX BURNER IN EACH TURBINE UTILIZES THE DRY LOW-NOX TECHNOLOGY TO CONTROL NOX EMISSIONS.	25	PPMVD	0.0995	LB/MMBTU

NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.5	MW	Nitrogen Oxides (NOx)	SOLONOX - A DRY LOW NOX TECHNOLOGY THAT REDUCES THE CONVERSION OF ATMOSPHERIC NITROGEN TO NOX BY OPERATING AT RELATIVELY LOW FUEL-TO-AIR RATIOS TO LOWER THE COMBUSTION TEMPERATURE IN THE TURBINE.	25	PPMVD	0.0995	LB/MMBTU
NV-0050	MGM MIRAGE	NV	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS	4.6	MMBTU/H	Nitrogen Oxides (NOx)	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU	5	PPMVD
OK-0127	WESTERN FARMERS ELECTRIC ANADARKO	OK	COMBUSTION TURBINE PEAKING UNIT(S)	NATURAL GAS	462.7	MMBTU/H	Nitrogen Oxides (NOx)	WATER INJECTION	25	PPM	42	LB/H
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	L-AREA GAS TURBINE	NATURAL GAS			Nitrogen Oxides (NOx)		27.46	LB/H	120.29	T/YR
TX-0525	TEXAS GENCO UNITS 1 AND2	TX	80 MW GAS TURBINE	NATURAL GAS	550	MMBTU/H	Nitrogen Oxides (NOx)	Dry-Low-Nox Combustors	62	LB/H	0	
*TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	TX	Refrigeration compressor turbines	natural gas	40000	hp	Nitrogen Oxides (NOx)	Dry low emission combustors	25	PPMVD	0	
*TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	(6) simple cycle turbines	natural gas	65	MW	Nitrogen Oxides (NOx)	DLN combustors	15	PPMVD	0	
*TX-0642	SINTON COMPRESSOR STATION	TX	Compression Turbine	natural gas	20000	hp	Nitrogen Oxides (NOx)	Solar's SoLoNOx dry emission control technology	25	PPMVD	0	
WA-0316	NORTHWEST PIPELINE CORP.- MT VERNON COMPRESSOR	WA	TURBINE, SIMPLE CYCLE	NATURAL GAS	12787	HP	Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTORS	25	PPMDV	258	LB/D
WA-0316	NORTHWEST PIPELINE CORP.- MT VERNON COMPRESSOR	WA	TURBINE, SIMPLE CYCLE	NATURAL GAS	5950	HP	Nitrogen Oxides (NOx)	DRY LOW NOX COMBUSTION	25	PPMVD @ 15% O2	129	LB/D
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Nitrogen Oxides (NOx)	SCR	5	PPMV AT 15% O2	7.7	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Trubine (EP04)	Natural Gas	40	MW	Nitrogen Oxides (NOx)	SCR	5	PPMV AT 15% O2	7.7	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Nitrogen Oxides (NOx)	SCR	5	PPMV AT 15% O2	7.7	LB/H
WY-0067	ECHO SPRINGS GAS PLANT	WY	TURBINES S35-S36	NATURAL GAS	12555	HP	Nitrogen Oxides (NOx)	SOLONOX	15	PPMV	25.6	T/YR
WY-0067	ECHO SPRINGS GAS PLANT	WY	TURBINE S34	NATURAL GAS	3856	HP	Nitrogen Oxides (NOx)	SOLONOX	25	PPMV	15.8	T/YR

RBLC Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines - CO Control

RBLC ID	Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	SOLAR MARS 90 TURBINE	NATURAL GAS	11.86	MW	GOOD COMBUSTION PRACTICES	385	LB/H	14	LB/H
*AK-0083	KENAI NITROGEN OPERATIONS	AK	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBtu/hr		50	PPMV	0	
AL-0208	EXXON MOBILE BAY -- NORTHWEST GULF FIELD	AL	TURBINE, SIMPLE CYCLE	NATURAL GAS	6000	bhp		50	PPM @ 15% O2	0	
AL-0209	EXXON MOBILE -- MOBILE BAY - BON SECURE BAY FIELD	AL	TURBINE, SIMPLE CYCLE	NATURAL GAS	3600	bhp		50	PPM @ 15% O2	0	
*CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	Three simple cycle combustion turbines	natural gas	799.7	mmbtu/hr	Good Combustion Control and Catalytic Oxidation (CatOx)	10	PPMVD AT 15% O2	19.8	LB/HR
*CO-0076	PUEBLO AIRPORT GENERATING STATION	CO	Turbines - two simple cycle gas	natural gas	799.7	mmbtu/hr each	Catalytic Oxidation.	55	LB/HR	0	
CO-0059	CHEYENNE STATION	CO	PHASE II TURBINE	NATURAL GAS	71.42	MMBTU/H	GOOD COMBUSTION PRACTICES	25	PPM @ 15% O2	0	
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Refrigeration Compressor Turbines (16)	Natural Gas	286	MMBTU/H	Good combustion practices and fueled by natural gas	43.6	LB/H	0	
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Generation Turbines (2)	Natural Gas	286	MMBTU/H	Good combustion practices and fueled by natural gas	17.46	LB/H	0	
MD-0035	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	21.7	MW		6	PPMVD	0	
MD-0036	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	12.2	MW	GOOD COMBUSTION PRACTICES AND OPERATION OF AN OXIDATION CATALYST SYSTEM	6	PPMVD	0	
*MI-0410	THETFORD GENERATING STATION	MI	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Efficient combustion	0.11	LB/MMBTU	0	
*ND-0029	PIONEER GENERATING STATION	ND	Natural gas-fired turbines	Natural gas	451	MMBtu/hr	Catalytic oxidation system	6	PPMVD	57.2	LB
*ND-0030	LONESOME CREEK GENERATING STATION	ND	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBtu/hr	Oxidation Catalyst	6	PPMVD	31.5	LB
NJ-0075	BAYONNE ENERGY CENTER	NJ	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	NATURAL GAS	603	MMBTU/H	CO OXIDATION CATALYST AND CLEAN BURNING FUELS	5	PPMVD@15%O 2	0.0112	LB/MMBTU
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	NJ	SIMPLE CYCLE TURBINE	Natural Gas	8940000	MMBtu/yr for six turbines combined	Oxidation Catalyst, Good combustion practices	5	PPMVD@15% O2	5.35	LB/H
NJ-0077	HOWARD DOWN STATION	NJ	SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(>25 MW)	NATURAL GAS	590	MMBtu/hr	THE TURBINE WILL UTILIZE A CATALYTIC OXIDIZER TO CONTROL CO EMISSION, IN ADDITION TO USING CLEAN BURNING	5	PPMVD@15%O 2	6.4	LB/H
NM-0051	CUNNINGHAM POWER PLANT	NM	Normal Mode (without Power Augmentation)	natural gas			Good Combustion Practices as defined in the permit.	77.2	LB/H	0	
NM-0051	CUNNINGHAM POWER PLANT	NM	Power Augmentation	natural gas			Good combustion practices as defined in the permit.	138.9	LB/H	0	

NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS	97.81	MMBTU/H	GOOD COMBUSTION PRACTICE	16	PPMVD	0.038	LB/MMBTU
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.5	MW	GOOD COMBUSTION PRACTICES - THE TURBINE IS OPERATED WITHIN THE PARAMETERS ALLOWING THE PROCESS	16	PPMVD	0.0388	LB/MMBTU
NV-0050	MGM MIRAGE	NV	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS	4.6	MMBTU/H	LEAN PRE-MIX TECHNOLOGY AND OXIDATION CATALYST	0.0056	LB/MMBTU	2.5	PPMVD
OK-0127	WESTERN FARMERS ELECTRIC ANADARKO	OK	COMBUSTION TURBINE PEAKING UNIT(S)	NATURAL GAS	462.7	MMBTU/H	NO CONTROLS FEASIBLE.	63	PPM	65.5	LB/H
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	L-AREA GAS TURBINE	NATURAL GAS				38.53	LB/H	168.74	T/YR
TX-0525	TEXAS GENCO UNITS 1 AND2	TX	80 MW GAS TURBINE	NATURAL GAS	550	MMBTU/H		52	LB/H	0	
*TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	TX	Refrigeration compressor turbines	natural gas	40000	hp		29	PPMVD	0	
*TX-0691	PH ROBINSON ELECTRIC GENERATING STATION	TX	(6) simple cycle turbines	natural gas	65	MW		25	PPMVD	0	
*TX-0642	SINTON COMPRESSOR STATION	TX	Compression Turbine	natural gas	20000	hp		50	PPMVD	0	
WA-0334	SUMAS COMPRESSOR STATION	WA	TURBINE, SIMPLE CYCLE	NATURAL GAS	100	MMBTU/H		50	PPMDV	14	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Oxidiation Catalyst	6	PPMV AT 15% O2	5.6	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Trubine (EP04)	Natural Gas	40	MW	Oxidation Catalyst	6	PPMV AT 15% O2	5.6	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Oxidation Catalyst	6	PPMV AT 15% O2	5.6	LB/H
WY-0067	ECHO SPRINGS GAS PLANT	WY	TURBINES S35-S36	NATURAL GAS	12555	HP	GOOD COMBUSTION PRACTICES	25	PPMV	26	T/YR
WY-0067	ECHO SPRINGS GAS PLANT	WY	TURBINE S34	NATURAL GAS	3856	HP	GOOD COMBUSTION PRACTICES	50	PPMV	19.3	T/YR

RBLC Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines - VOC Control

RBLC ID	Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
*AK-0083	KENAI NITROGEN OPERATIONS	AK	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBtu/hr		0.0021	LB/MMBTU	0	
CA-1174	EL CAJON ENERGY LLC	CA	Gas turbine simple cycle	Natural gas	49.95	MW	Oxydation catalyst	2	PPMV	0	
CA-1175	ESCONDIDO ENERGY CENTER LLC	CA	Gas turbine simple cycle	Natural gas	46.5	MW	oxydation catalyst	2	PPMV@15% OXYGEN	0	
CA-1176	ORANGE GROVE PROJECT	CA	Gas turbine simple cycle	Natural gas	49.8	MW	Oxidation catalyst	2	PPM	0	
*CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	Three simple cycle combustion turbines	natural gas	799.7	mmbtu/hr	Good Combustion Control and Catalytic Oxidation (CatOx)	2.5	PPMVD AT 15% O2	0	
CO-0059	CHEYENNE STATION	CO	PHASE II TURBINE	NATURAL GAS	71.42	MMBTU/H	GOOD COMBUSTION PRACTICES	3	PPM @ 15% O2	0	
FL-0266	PAYNE CREEK GENERATING STATION/SEMINOLE	FL	SIMPLE CYCLE COMBUSTION TURBINES	NATURAL GAS	30	MW	OXIDATION CATALYST	90	% REMOVAL	0	
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Refrigeration Compressor Turbines (16)	Natural Gas	286	MMBTU/H	Good combustion practices and fueled by natural gas	0.66	LB/H	0	
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Generation Turbines (2)	Natural Gas	286	MMBTU/H	Good combustion practices and fueled by natural gas	0.66	LB/H	0	
LA-0232	STERLINGTON COMPRESSOR STATION	LA	COMPRESSOR TURBINE NO. 1	NATURAL GAS	79.1	MMBTU/H	GOOD COMBUSTION PRACTICES INCLUDING THE USE OF CLEAN BURNING FUELS SUCH AS NATURAL GAS	2.62	LB/H	11.46	T/YR
LA-0232	STERLINGTON COMPRESSOR STATION	LA	COMPRESSOR TURBINE NO. 2	NATURAL GAS	79.1	MMBTU/H	GOOD COMBUSTION PRACTICES INCLUDING THE USE OF CLEAN BURNING FUELS SUCH AS NATURAL GAS	2.62	LB/H	11.46	T/YR
MD-0035	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	21.7	MW	NATURAL GAS COMBUSTION AND CATALYTIC OXIDATION	0.003	LB/MMBTU	0	
MD-0036	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	12.2	MW	USE OF GOOD COMBUSTION PRACTICES AND OPERATION OF AN OXIDATION CATALYST SYSTEM	0.6	LB/H	0.4	LB/H
*MI-0410	THETFORD GENERATING STATION	MI	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Efficient combustion; natural gas fuel.	0.017	LB/MMBTU	0	
NJ-0075	BAYONNE ENERGY CENTER	NJ	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	NATURAL GAS	603	MMBTU/H	CO OXIDATION CATALYST AND POLLUTION PREVENTION, BURNING CLEAN FUELS, NATURAL GAS AND	1.93	LB/H	2.5	PPMVD@15%O2
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING STATION	NJ	SIMPLE CYCLE TURBINE	Natural Gas	8940000	MMBtu/yr for six turbines combined	Oxidation Catalyst and good combustion practices, use of natural gas.	4	PPMVD@15% O2	2.33	LB/H
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS	97.81	MMBTU/H	GOOD COMBUSTION PRACTICE	0.0069	LB/MMBTU	0.84	L/H
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.5	MW	GOOD COMBUSTION PRACTICE	0.0069	LB/MMBTU	0.84	LB/H

NV-0050	MGM MIRAGE	NV	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS	4.6	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY AND OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S	0.024	LB/MMBTU	0.11	LB/H
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	L-AREA GAS TURBINE	NATURAL GAS				0.59	LB/H	2.56	T/YR
TX-0525	TEXAS GENCO UNITS 1 AND2	TX	80 MW GAS TURBINE	NATURAL GAS	550	MMBTU/H		2.2	LB/H	0	
*TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	TX	Refrigeration compressor turbines	natural gas	40000	hp	good combustion practices	0.6	LB/HR	0	
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Trubine (EP04)	Natural Gas	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3	LB/H
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	Oxidation Catalyst	3	PPMV AT 15% O2	3	LB/H
WY-0067	ECHO SPRINGS GAS PLANT	WY	TURBINES S35-S36	NATURAL GAS	12555	HP	GOOD COMBUSTION PRACTICES	25	PPMV	3	T/YR
WY-0067	ECHO SPRINGS GAS PLANT	WY	TURBINE S34	NATURAL GAS	3856	HP	GOOD COMBUSTION PRACTICES	50	PPMV	1.1	T/YR

RBLC Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines - PM Control

RBLC ID	Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	SOLAR MARS 90 TURBINE	NATURAL GAS	11.86	MW	GOOD OPERATION PRACTICES	10	% OPACITY	0	
AK-0080	ANCHORAGE MUNICIPAL LIGHT & POWER	AK	Combustion	Natural Gas	408	MMBtu/hr	Good operation and combustion practices	0.0066	LB/MMBTU	0	
AK-0081	POINT THOMSON PRODUCTION FACILITY	AK	Combustion	Natural Gas	7520	kW	Good combustion and operating practices	0.0066	LB/MMBTU	0	
*AK-0083	KENAI NITROGEN OPERATIONS	AK	Five (5) Natural Gas Fired Combustion Turbines	Natural Gas	37.6	MMBtu/hr		0.0074	LB/MMBTU	0	
*CO-0073	PUEBLO AIRPORT GENERATING STATION	CO	Three simple cycle combustion turbines	natural gas	799.7	mmbtu/hr	Use of pipeline quality natural gas and good combustor design	6.6	LB/HR	0	
*CO-0075	PUEBLO AIRPORT GENERATING STATION	CO	Turbine - simple cycle gas	natural gas	375	mmbtu/hr	Firing of pipeline quality natural gas as defined in 40 CFR Part 72. Specifically, the owner or the operator shall demonstrate that the natural gas	4.8	LB/HR	0	
FL-0266	PAYNE CREEK GENERATING STATION/SEMINOLE	FL	SIMPLE CYCLE COMBUSTION TURBINES	NATURAL GAS	30	MW	CLEAN FUELS	10	% OPACITY	0	
LA-0219	CREOLE TRAIL LNG IMPORT TERMINAL	LA	GAS TURBINE GENERATOR NOS. 1-4	LNG	30	MW EA.		2.11	LB/H	8.49	T/YR
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Refrigeration Compressor Turbines (16)	Natural Gas	286	MMBTU/H	Good combustion practices and fueled by natural gas	2.08	LB/H	0	
MD-0035	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	21.7	MW		0.0066	LB/MMBTU	0	
MD-0036	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	12.2	MW	USE OF LNG QUALITY, LOW SULFUR NATURAL GAS	0.0066	LB/MMBTU	0	
*MI-0410	THETFORD GENERATING STATION	MI	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	natural gas	171	MMBTU/H	Efficient combustion; natural gas fuel.	0.02	LB/MMBTU	0	
*ND-0029	PIONEER GENERATING STATION	ND	Natural gas-fired turbines	Natural gas	451	MMBtu/hr		5.4	LB	0	
*ND-0030	LONESOME CREEK GENERATING STATION	ND	Natural Gas Fired Simple Cycle Turbines	Natural gas	412	MMBtu/hr		5	LB/H	0	
NJ-0075	BAYONNE ENERGY CENTER	NJ	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	NATURAL GAS	603	MMBTU/H	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PPM.	5	LB/H	0	
NJ-0076	PSEG FOSSIL LLC KEARNY GENERATING	NJ	SIMPLE CYCLE TURBINE	Natural Gas	8940000	MMBtu/yr for six turbines combined	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H	0	
NJ-0077	HOWARD DOWN STATION	NJ	SIMPLE CYCLE (NO WASTE HEAT RECOVERY)(>25 MW)	NATURAL GAS	590	MMBtu/hr	USE OF CLEAN BURNING FUELS; NATURAL GAS AS PRIMARY FUEL AND ULTRA LOW SULFUR DISTILLATE OIL WITH 15	5	LB/H	0	

NM-0051	CUNNINGHAM POWER PLANT	NM	Normal Mode (without Power Augmentation)	natural gas			Good Combustion Practices as described in the permit.	5.4	LB/H	0	
NM-0051	CUNNINGHAM POWER PLANT	NM	Power Augmentation	natural gas			Good combustion practices as defined in the permit.	5.4	LB/H	0	
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS	97.81	MMBTU/H	NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0066	LB/MMBTU	0.65	L/H
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.5	MW	PROPER OPERATION OF THE TURBINE	0.0066	LB/MMBTU	0.81	LB/H
NV-0050	MGM MIRAGE	NV	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS	4.6	MMBTU/H	GOOD COMBUSTION PRACTICES AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.202	LB/MMBTU	0.93	LB/H
NY-0093	TRIGEN-NASSAU ENERGY CORPORATION	NY	TURBINE, COMBINED CYCLE	NATURAL GAS	79.9	mw		4.66	LB/H	0.0141	LB/MMBTU
OK-0127	WESTERN FARMERS ELECTRIC ANADARKO	OK	COMBUSTION TURBINE PEAKING UNIT(S)	NATURAL GAS	462.7	MMBTU/H	NO CONTROLS FEASIBLE.	4	LB/H	0	
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	L-AREA GAS TURBINE	NATURAL GAS				2.09	LB/H	9.16	T/YR
TX-0525	TEXAS GENCO UNITS 1 AND2	TX	80 MW GAS TURBINE	NATURAL GAS	550	MMBTU/H		7	LB/H	0	
*TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	TX	Refrigeration compressor turbines	natural gas	40000	hp		0.72	LB/HR	0	
*TX-0691	PH ROBINSON ELECTRIC GENERATING	TX	(6) simple cycle turbines	natural gas	65	MW		0		0	
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP03)	Natural Gas	40	MW	good combustion practices	4	LB/H	17.5	TONS
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Trubine (EP04)	Natural Gas	40	MW	good combustion practices	4	LB/H	17.5	TONS
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	WY	Simple Cycle Turbine (EP05)	Natural Gas	40	MW	good combustion practices	4	LB/H	17.5	TONS

RBLC Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines - SO2 Control

RBLC ID	Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	SOLAR MARS 90 TURBINE	NATURAL GAS	11.86	MW	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250	PPMV	0	
AK-0067	CENTRAL GAS FACILITY	AK	GE FRAME 6 INJECTION TURBINES COMPRESSORS (4)	NATURAL GAS	53665	HP ISO		300	PPMV	0	
FL-0266	PAYNE CREEK GENERATING STATION/SEMINOLE	FL	SIMPLE CYCLE COMBUSTION TURBINES	NATURAL GAS	30	MW	CLEAN FUELS	1	GRAIN/100 C.F. GS	0.05	% SULFUR OIL
FL-0287	OLEANDER POWER PROJECT	FL	SIMPLE CYCLE COMBUSTION TURBINE	NATURAL GAS	190	MW	CLEAN FUELS	1.5	GR S/100 SCF	0.05	% S
FL-0310	SHADY HILLS GENERATING STATION	FL	TWO SIMPLE CYCLE COMBUSTION TURBINE - MODEL 7FA	NATURAL GAS	170	MW	FIRING OF NATURAL GAS WITH A MAXIMUM S CONTENT AT 2GR/100 SCF AND ULTRA LOW SULFUR DIESEL FUEL OIL WITH A MAXIMUM S	2	GR S/100 SCF NG	0.0015	S BY WEIGHT FUEL OIL
MD-0035	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	21.7	MW		0.58	LB/MW-H	0	
MD-0036	DOMINION	MD	COMBUSTION TURBINE	NATURAL GAS	12.2	MW	USE OF LNG QUALITY, LOW SULFUR NATURAL GAS	0.9	LB/MW-H	0	
NJ-0075	BAYONNE ENERGY CENTER	NJ	COMBUSTION TURBINES, SIMPLE CYCLE , ROLLS ROYCE, 8	NATURAL GAS	603	MMBTU/H	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PPM.	1.22	LB/H	0	
NM-0051	CUNNINGHAM POWER PLANT	NM	Normal Mode (without Power Augmentation)	natural gas	0		5.25 gr/100 SCF total sulfur limit in fuel.	22.1	LB/H	0	
NM-0051	CUNNINGHAM POWER PLANT	NM	Power Augmentation	natural gas	0		5.25 gr/scf total sulfur in fuel	22.1	LB/H	0	
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS	97.81	MMBTU/H	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0034	LB/MMBTU	0.33	L/H
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.5	MW	USING LOW-SULFUR NATURAL GAS ONLY	0.0034	LB/MMBTU	0.42	LB/H
NV-0050	MGM MIRAGE	NV	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS	4.6	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY.	0.0065	LB/MMBTU	0.03	LB/H
OH-0304	ROLLING HILLS GENERATING PLANT	OH	NATURAL GAS FIRED TURBINES (5)	NATURAL GAS	209	MW		5.9	LB/H	11.8	T/YR
OH-0333	DAYTON POWER & LIGHT ENERGY LLC	OH	Turbines (4), simple cycle, natural gas	NATURAL GAS	15020	H/YR	Fuel oil with no more than 0.05% by weight sulfur	0.0026	LB/MMBTU	138.6	T/YR
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	L-AREA GAS TURBINE	NATURAL GAS				0.03	LB/H	0.12	T/YR
TX-0504	NAVASOTA POWER GENERATION FACILITY	TX	TURBINES WITH 165 MMBTU/HR DUCT BURNERS	NATURAL GAS	75	MW	USE OF NATURAL GAS	1.7	LB/H	6.2	T/YR

TX-0504	NAVASOTA POWER GENERATION FACILITY	TX	TURBINES WITHOUT 165 MMBTU/HR DUCT BURNERS	NATURAL GAS	75	MW		1.5	LB/H	0	
TX-0504	NAVASOTA POWER GENERATION FACILITY	TX	STARTUP, SHUTDOWN, MAINTENANCE	NATURAL GAS	75	MW		1.7	LB/H	0	
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	TX	TURBINE FIRING NATURAL GAS W/ BURNERS		80	MW		1	LB/H	0	
TX-0506	NRG TEXAS ELECTRIC POWER GENERATION	TX	TURBINE FIRING NATURAL GAS W/O BURNERS		80	MW		0.7	LB/H	0	
TX-0509	PONDEROSA PINE ENERGY PARTNERS COGENERATION	TX	TURBINE AND 375 MMBTU/HR HEAT RECOVERY STEAM SYSTEM	NATURAL GAS	250	MW		87.22	LB/H	92.5	T/YR
TX-0525	TEXAS GENCO UNITS 1 AND2	TX	80 MW GAS TURBINE	NATURAL GAS	550	MMBTU/H		0.7	LB/H	0	
TX-0525	TEXAS GENCO UNITS 1 AND2	TX	80 MW GAS TURBINE		550	MMBTU/H		1	LB/H	0	
*TX-0672	CORPUS CHRISTI LIQUEFACTION PLANT	TX	Refrigeration compressor turbines	natural gas	40000	hp		0.31	LB/HR	0	
*TX-0695	ECTOR COUNTY ENERGY CENTER	TX	(2) combustion turbines	natural gas	180	MW		1	GR/100 DSCF	0	
*TX-0701	ECTOR COUNTY ENERGY CENTER	TX	Simple Cycle Combustion Turbines	natural gas	180	MW	Firing pipeline quality natural gas and good combustion practices.	0		0	
WI-0240	WE ENERGIES CONCORD	WI	COMBUSTION TURBINE, 100 MW, NATURAL GAS	NATURAL GAS	100	MW	USE ONLY NATURAL GAS	0.0068	LB/MMBTU	0	

RBLC Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines - CO2 equivalent Control

RBLC ID	Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
AK-0083	Kenai Nitrogen Operations	AK	Solar Turbine/Generator Set	Natural Gas	37.6	MMBtu/hr	No Controls Feasible	59.61	tons/MMcf 3-hr avg	91500	tons/yr combined
AK-0081	EXXONMOBIL CORPORATION - POINT THOMSON PRODUCTION FACILITY	AK	Combustion	Natural Gas	7520	kW	Good Combustion and Operating Practices	0	-	0	-
AK-0080	MUNICIPALITY OF ANCHORAGE - ANCHORAGE MUNICIPAL LIGHT & POWER	AK	Combustion	Natural Gas	408	MMBtu/hr	Good operating and combustion practices	0	-	0	-
MI-0410	THETFORD GENERATING STATION	MI	FG-PEAKERS: 2 natural gas fired simple cycle combustion turbines	Natural Gas	171	MMBtu/hr	Efficient combustion; energy efficiency	20141	tons/yr 12-month rolling time period	0	-
TX-0636	HOUSTON CENTRAL GAS PLANT	TX	Supplemental Heaters	Natural Gas	25	MMBtu/hr	No Controls Feasible Limit use to 600 hours per year and use of Good Combustion Practices.	0	-	0	-
CA-1223	PIO PICO ENERGY CENTER	CA	Combustion Turbines (Normal Operations)	Natural Gas	300	MW	No Controls Feasible	1328	lb/MW-hr	720	Rolling Operating hour average
CO-0075	BLACK HILLS ELECTRIC GENERATION, LLC - PUEBLO AIRPORT GENERATING STATION	CO	Turbine - simple cycle gas	Natural Gas	375	MMBtu/hr	Good Combustion Control	1600	lb/MW-hr Gross rolling 365-day average	193555	tons/hr rolling 365-day average
LA-0257	SABINE PASS LNG TERMINAL	LA	Simple Cycle Refrigeration Compressor Turbines (16)	Natural Gas	286	MMBtu/hr	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107	tons/yr annual maximum from facilitywide		
MD-0043	PERRYMAN GENERATING STATION	MD	60-MW Simple cycle combustion turbines, firing natural gas	Natural Gas	120	MW	USE OF NATURAL GAS. ENERGY EFFICIENCY DESIGN - USE OF INLET FOGGING/WET COMPRESSION, INSULATION BLANKETS TO REDUCE HEAT LOSS, AND FUEL GAS PREHEATING.	1394	lb/MW-hr 12-month rolling		
ND-0028	MONTANA-DAKOTA UTILITIES CO. - R.M. HESKETT STATION	ND	Combustion Turbines	Natural Gas	986	MMBtu/hr	No Controls Feasible	413198	tons/12 month rolling total		
ND-0029	BASIN ELECTRIC POWER COOPERATIVE PIONEER GENERATING STATION	ND	Natural gas-fired turbines	Natural Gas	451	MMBtu/hr	No Controls Feasible	243147	tons/12 month rolling total per each unit		
ND-0030	BASIN ELECTRIC POWER COOP. LONESOME CREEK GENERATING STATION	ND	Natural Gas Fired Simple Cycle Turbines	Natural Gas	412	MMBtu/hr	High efficiency turbines	220122	tons/12 month rolling total per each unit		
TX-0679	CORPUS CHRISTI LIQUEFACTION PLANT	TX	Refrigeration Compressor Turbines	Natural Gas	40000	hp	install efficient turbines, follow the turbine manufacturer's emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion and efficient operation. Compressors shall be inspected and maintained according to a written maintenance plan to maintain efficiency.	146754	tpy rolling 12-month basis		
TX-0735	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC. - ANTELOPE ELK ENERGY CENTER	TX	Simple Cycle Turbine & Generator	Natural Gas	202	MW	Energy efficiency, good design & combustion practices	1304	lb/MW-hr Operation of each turbine limited to 4,572 hours per year		
TX-0753	GUADALUPE GENERATING STATION	TX	Simple Cycle Turbine & Generator	Natural Gas	10673	Btu/kWh	No Controls Feasible	1293	lb/MW-hr 12-month rolling	20.8	tons/hr 12-month rolling average basis
TX-0757	INDECK WHARTON, LLC INDECK WHARTON ENERGY CENTER	TX	Simple Cycle Combustion Turbine, SGT-5000F(5)	Pipeline Natural Gas	0		No Controls Feasible	1337	lb CO2/MW-hr (Gross) 2500 Operational hr rolling Daily/CT	358529	tpy CO2e 12-month rolling
TX-0758	ECTOR COUNTY ENERGY CENTER	TX	Simple Cycle Combustion Turbine, GE 7FA.03	Natural Gas	11707	Btu/kWh (HHV)	No Controls Feasible	1393	lb CO2/MW-hr (Gross) 2500 Operational hr rolling Daily/CT	239649	tpy CO2e 12-month rolling

CT Database Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines -NOx Control

Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
Middletown Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Water Injection and SCR	4.35	lb/hr	2.5	ppmvd @ 15 % O2
Devon Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	10/15/2008	Water Injection and SCR	4.35	lb/hr	2.5	ppmvd @ 15 % O2
PSEG New Haven LLC	CT	Combustion Turbine	Natural Gas	50	MW	1/13/2011	Selective catalytic reduction	4.38	lb/hr	2.5	ppmvd @ 15 % O2
Alfred L. Pierce Generating Station	CT	GE 7EA Combustion Turbine Generator Set	Natural Gas	1.13	MMft^3/hr	12/28/2006	Dry Low Nox combustion, and SCR with 50% control efficiency	38	lb/hr	9	ppmvd @ 15 % O2
Iroquois Pipeline Operating Company	CT	Solar Taurus 60 with SoLoNOx Gas Compression Turbine	Natural Gas	73	MMBtu/hr	3/7/2007	Solar SoLoNOx technology	3.9	lb/hr	15	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	5.78 MW Natural gas fired Solar Taurus turbine with oxidation catalyst and SoLoNOx	Natural Gas	5.78	MW	12/22/2014	SoLoNOx	2.38	lb/hr	9	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	8.9 MW Solar Taurus turbine with SoLoNOx II	Natural Gas	98.6	MMBtu	6/28/2006	SoLoNOx II	5.34	lb/hr	15	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	13.5 MW natural gas fired simple cycle turbine with oxidation catalyst and SoLoNOx	Natural Gas	13.5	MW	1/29/2015	SoLoNOx	4.69	lb/hr	9	ppmvd @ 15 % O2
Connecticut Jet Power	CT	Peaking Combustion Turbine	Natural Gas	20	MW	2/15/2008	Water injection, fuel limitation with annual combined emissions for both turbines	0.175	lb/MMBtu	40	ppmvd @ 15 % O2
Kimberly-Clark Corporation	CT	Solar Titan 130 CT#2	Natural Gas	174.84	MMBTU/hr	10/9/2007	SoLoNOx technology or equivalent	9.68	lb/hr	15	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	Natural Gas compressor, turbine	Natural Gas	140	MMBtu/hr	12/27/2006	Lean pre-mix combustion (SoLoNOx)	7.51	lb/hr	15	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	Natural Gas compressor, turbine	Natural Gas	75.525	MMBtu/hr	12/27/2006	Lean pre-mix combustion (SoLoNOx)	3.97	lb/hr	15	ppmvd @ 15 % O2
Waterside Power LLC	CT	Peaking Combustion Turbine	Natural Gas	23.2	MW	5/28/2008	Water injection, fuel limitation; annual limitation is for all (3) turbines	0.091	lb/MMBtu	25	ppmvd @ 15 % O2

CT Database Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines -CO Control

Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
Middletown Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Add-on Control, Oxidation Catalyst	8	lb/hr	5	ppmvd @ 15 % O2
Devon Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Add-on Control, Oxidation Catalyst	8	lb/hr	5	ppmvd @ 15 % O2
PSEG New Haven LLC	CT	Combustion Turbine	Natural Gas	50	MW	1/13/2011	Add-on Control, Catalytic oxidation	5.12	lb/hr	5	ppmvd @ 15 % O2
Alfred L. Pierce Generating Station	CT	GE 7EA Combustion Turbine Generator Set	Natural Gas	1.13	MMft^3/hr	12/28/2006	Fuel limitation	63	lb/hr		
Iroquois Pipeline Operating Company	CT	Solar Taurus 60 with SoLoNOx Gas Compression Turbine	Natural Gas	73	MMBtu/hr	3/7/2007	Good combustion practices and pipeline quality natural gas	4	lb/hr	25	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	5.78 MW Natural gas fired Solar Taurus turbine with oxidation catalyst and SoLoNOx	Natural Gas	5.78	MW	12/22/2014	Catalytic Oxidizer	0.25	lb/hr	25	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	8.9 MW Solar Taurus turbine with SoLoNOx II	Natural Gas	98.6	MMBtu	6/28/2006	DLN	5.42	lb/hr		
Algonquin Gas Transmission LLC	CT	13.5 MW natural gas fired simple cycle turbine with oxidation catalyst and SoLoNOx	Natural Gas	13.5	MW	1/29/2015	Catalytic Oxidizer	0.4	lb/hr	25	ppmvd @ 15 % O2
Connecticut Jet Power	CT	Peaking Combustion Turbine	Natural Gas	20	MW	2/15/2008	Good combustion practices; fuel limitation;	214.6	lb/hr		
Kimberly-Clark Corporation	CT	Solar Titan 130 CT#2	Natural Gas	174.84	MMBTU/hr	10/9/2007	Oxidation Catalyst	0.982	lb/hr		
Algonquin Gas Transmission LLC	CT	Natural Gas compressor, turbine	Natural Gas	140	MMBtu/hr	12/27/2006	Good Combustion	7.62	lb/hr	25	ppmvd @ 15 % O2
Algonquin Gas Transmission LLC	CT	Natural Gas compressor, turbine	Natural Gas	75.525	MMBtu/hr	12/27/2006	Lean pre-mix combustion (SoLoNOx)	4.02	lb/hr	25	ppmvd @ 15 % O2
Waterside Power LLC	CT	Peaking Combustion Turbine	Natural Gas	23.2	MW	5/28/2008	Good combustion practices; annual limitation is for all (3) turbines	0.117	lb/MMBtu		

CT Database Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines -VOC Control

Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Limit 1 Units	Emission Limit 2	Limit 2 Units
Middletown Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Add-on Control, Oxidation Catalyst	1.11	lb/hr		
Devon Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Add-on Control, Oxidation Catalyst	1.11	lb/hr		
PSEG New Haven LLC	CT	Combustion Turbine	Natural Gas	50	MW	1/13/2011	Both P2 and Add-on, Catalytic Oxidation and good combustion practices	1.11	lb/hr	2	ppmvd @ 15 % O2

CT Database Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines- PM Control

Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
Middletown Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Good combustion practices and optimizaiton of SCR; fuel limitation	6	lb/hr		
Devon Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	10/15/2008	Good combustion practices and optimizaiton of SCR; fuel limitation	6	lb/hr		
PSEG New Haven LLC	CT	Combustion Turbine	Natural Gas	50	MW	1/13/2011	Clean fuels and good combustion practices	6	lb/hr		
Alfred L. Pierce Generating Station	CT	GE 7EA Combustion Turbine Generator Set	Natural Gas	1.13	MMft^3/hr	12/28/2006	No control- Fuel limitation and low sulfur fuel	10	lb/hr		
Waterside Power LLC	CT	Peaking Combustion Turbine	Natural Gas	23.2	MW	5/28/2008	Fuel limitation to less than 15 tpy; annual limitation is for all (3) turbines	0.006	lb/MMBtu		

CT Database Search Results for Natural Gas-Fired Simple Cycle Combustion Turbines- SO2 Control

Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
Alfred L. Pierce Generating Station	CT	GE 7EA Combustion Turbine Generator Set	Natural Gas	1.13	MMft^3/hr	12/28/2006	Fuel limitation and low sulfur fuel	1.94	lb/hr		
Connecticut Jet Power	CT	Peaking Combustion Turbine	Natural Gas	20	MW	2/15/2008	Pollution Prevention	-	-	-	
Middletown Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Pollution Prevention	-	-	-	
Devon Power LLC	CT	Peaking Combustion Turbine	Natural Gas	50	MW	8/27/2008	Pollution Prevention	-	-	-	
PSEG New Haven LLC	CT	Combustion Turbine	Natural Gas	50	MW	1/13/2011	Clean Fuels	0.95	lb/hr	0	
Waterside Power LLC	CT	Peaking Combustion Turbine	Natural Gas	23.2	MW	5/28/2008	Fuel limitation; ULSD; annual limitation is for all (3) turbines	0.002	lb/MMBtu		

CT Database Search Results for - CO_2 equivalent Control

Facility Name	State	Process Name	Primary Fuel	Throughput	Throughput Units	Control Method Description	Emission Limit 1	Emission Limit 1 Units	Emission Limit 2	Emission Limit 2 Units
Connecticut Jet Power	CT	Peaking Combustion Turbine	Diesel	20	MW	Fuel limitation; these units are required to offset the CO2 emissions compared to a modern turbine with either RGGI credits or by planting biomass sinks. GHG BACT did not apply to these units when permitted.	-	-	--	--
Electric Boat Corporation	CT	Boiler	Natural Gas	121.4	MMBtu/hr	Energy efficiency and fuel conservation. No permit limitation on emission rates	-	-	-	-
Montville Power LLC	CT	42 MW biomass stoker fired; 82 MW tangentially fired fossile fuel fired utility boiler	Biomass	600	MMBtu/hr	Enforceable heat rate (gross) for all fuels, energy efficiency measures, CO2 CEMs, preventative measures for fugitive GHG emissions	15564	btu/kW-hr	-	-
RockTenn	CT	170 MMBtu/hr natural gas fired boiler	Natural Gas	170.11	MMBtu/hr	Good Combustion, annual tune-up	117.02	lb/MMBtu		
Yale University	CT	Cogen facility: 7.9 MW Solar Taurus 70 Gas Turbine and a Victory Heat Recovery Steam Generator with a Coen Grid Style Duct Burner (No. 1)	Natural Gas	-0.0005T^2 - 0.1859T + 95.555	MMBtu/hr	No Control - Use of state-of-the-art efficient, inherently low emitting equipment.	17988	lb/hr		

NOx MassDEP Top Case BACT Guidelines

BACT Determination	State	Source Type	Fuel	BACKUP FUEL	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units
Plan Approval, Transmittal Number W120701	MA	Simple Cycle Turbine > 10 MW/hr	Natural Gas	No. 2 Fuel Oil	6/1/2011	Dry Low NOx Combustor, SCR, CEMS	2.5	ppmvd @ 15% O_2
310 CMR 7.26(43) IRP Regulation	MA	Combustion Turbine 1 MW to 10 MW	Natural Gas		6/1/2011	SCR (possible required technology)	0.14	lb/MW-hr
310 CMR 7.26(43) IRP Regulation	MA	Combustion Turbine Less Than 1 MW	Natural Gas	No. 2 Fuel Oil	6/1/2011		0.47	lb/MW-hr

CO MassDEP Top Case BACT Guidelines

BACT Determination	State	Source Type	Fuel	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units
Plan Approval, Transmittal Number W120701	MA	Simple Cycle Turbine > 10 MW/hr	Natural Gas	6/1/2011	Oxidation Catalyst, CEMS	5.0	ppmvd @ 15% O_2
310 CMR 7.26(43) IRP Regulation	MA	Combustion Turbine 1 MW to 10 MW	Natural Gas	6/1/2011	Oxidation Catalyst (possible required technology)	0.09	lb/MW-hr
310 CMR 7.26(43) IRP Regulation	MA	Combustion Turbine Less Than 1 MW	Natural Gas	6/1/2011		0.47	lb/MW-hr

VOC MassDEP Top Case BACT Guidelines

BACT Determination	State	Source Type	Fuel	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units
Plan Approval, Transmittal Number W120701	MA	Simple Cycle Turbine > 10 MW/hr	Natural Gas	6/1/2011	Oxidation Catalyst	2.5	ppmvd @ 15% O_2

PM MassDEP Top Case BACT Guidelines

None Found

SO2 MassDEP Top Case BACT Guidelines

None Found

CO2e MassDEP Top Case BACT Guidelines

BACT Determination	State	Source Type	Fuel	DATE OF DETERMINATION	Control Method Description	Emission Limit 1	Emission Limit 1 Units
Plan Approval, Transmittal Number W120701	MA	Simple Cycle Turbine > 10 MW/hr	Natural Gas	6/1/2011			
310 CMR 7.26(43) IRP Regulation	MA	Combustion Turbine 1 MW to 10 MW	Natural Gas	6/1/2011	Oxidation Catalyst (possible required technology)	1900	lb/MW-hr

Attachment E - Summary of Proposed BACT

Pollutant	RBLC	MA Top Case BACT	CT BACT	Proposed BACT	Notes
CO	5 ppmvd at 15% O_2	5 ppmvd at 15% O_2	5 ppmvd at 15% O_2	25 ppmvd at 15% O_2 (before control) 1.25 ppmvd at 15% O_2 (after control) or 0.20 lb/hr (after control)	The before control BACT limit is based on the Solar guarantee for SoLoNOx. The after control proposed BACT limit is based on the the use of an oxidation catalyst with a 95% control efficiency for CO. The 0.2 lb/hr CO limit corresponds to a concentration of 1.25 ppmvd at 15% $O_{2.}$ This concentration is lower than RBLC, MA or CT BACT determinations.
VOC	2-4 ppmvd at 15% O_2 (with Oxidation Catalyst control)	2.5 ppmvd at 15% O_2 (with Oxidation Catalyst Control)	2 ppmvd at 15% O_2 (with Oxidation Catalyst Control)	0.25 lb/hr (after Oxidation Catalyst control)	The after control proposed BACT limit is based on the use of an oxidation catalyst with a 50% control efficiency for VOC. The oxidation catalyst is the top ranked BACT for control of VOC as discussed in Section 5.5 of the application report and is the system cited in the RBLC and MassDEP BACT determinations. The 0.25 lb/hr VOC limit corresponds to a concentration of 2.4 ppmvd at 15% O_2 (based on an average VOC molecular weight of 18.37 lb/lb-mole). This concentration is lower than the MassDEP Top-Case BACT and within the RBLC range. Both of the determinations are based on 50 megawatt (MW) units. The Solar unit is significantly smaller at 6.46 MW.
PM	0.0066 lb/MMBtu	N/A	0.0066 lb/MMBtu	0.0066 lb/MMBtu	The proposed BACT limit is equal to the RBLC, MA, and CT determinations. The limit will be achieved through the use of pipeline quality natural gas along with good combustion and operating practices.
SO_2	1 grain per 100 scf NG	N/A	0.002 lb/MMBtu	14.29 lb/MMscf (based on 5 grains per 100 scf NG)	The RBLC and CT BACT determinations are based on the sulfur content of natural gas supplied to the sources by the local distribution company. As the new Solar Taurus 60-7802 turbine at the Weymouth Compressor Station will be fired using the pipeline gas, the proposed BACT is based on a sulfur content of 5 grains/100 scf per Algonquin's tariff for pipeline quality natural gas.

Table 1. Cost Analysis Supporting Information for SCR

Parameter	Turbine	Units	Reference	Notes
Maximum Heat Capacity	74.91	MMBtu/hr	1	
Maximum Output	6,460	kW	1	
Potential Inlet NO_X Emissions	32.97	lb/MMscf	1	
Potential Emissions NO_X	9.96	tpy	1	
Removal Efficiency	90	%		**From Budget Costs from FERCO (Appendix E)**
Pollutant Removed	8.96	tpy	3	
Aqueous Ammonia Requirement	39.420	ton/yr		**From Budget Costs from FERCO, converted 9 lb/hr to tpy**
Catalyst Cost, Disposal	15.00	$/ft^3	4	
Catalyst Cost, Replacement	20,000	$	4	
Aqueous Ammonia Cost	295.75	$/ton		Calculated, Refer to Table 3
Ammonia Vaporizer Cost	0.75	$/hr	4	
Dilution Blower Cost	0.10	$/hr	4	
Natural Gas Cost	11.1	$/MMBtu	5	
Electricity Cost	0.130	$/kW-hr	6	
Loss	1.2	%	7	
Catalyst Life	3	years	8	
SCR Equipment Life	20	years	11	
Interest Rate	7%	%	8	
CRF (20 Years)	0.0944		9	
CRF (3 Years)	0.3811		9	
1998 $ (December)	163.9	n/a	10	
1999 $	166.6	n/a	10	
2004 $	188.9	n/a	10	
2015 $ (July)	238.7	n/a	10	

1. Turbine information for new Taurus 60 to be installed at the Weymouth compressor station.
2. Assumed efficiency based on EPA's Air Pollution Control Technology Fact Sheet: http://www.epa.gov/ttn/catc/dir1/fscr.pdf
3. Pollutant Removed (tpy) = (Removal Efficiency, %) × (Potential Emissions, tpy).
4. Estimated value based on previous BACT analysis experience.
5. Industrial natural gas cost obtained from U.S. Energy Information Administration for 2014 for MA: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SMA_a.htm
6. Industrial June 2015 electricity cost for MA: http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a
7. Loss estimated as 0.2% per inch @ 6 inches.
8. Based on OAQPS Manual, Section 4.2, Chapter 2, page 2-50.
9. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49.
10. Values based on U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.
11. Based on OAQPS, Section 4, Chapter 2, pg 2-48: http://www.epa.gov/ttn/catc/dir1/cs4-2ch2.pdf

*May 2018 Update - The annual NOx PTE has been revised from 9.96 tpy to 10.03 tpy due to the change in estimated emissions for SU/SD. This slight increase is inconsequential to the results of the economic analysis. Therefore, these numbers have not been revised.

Table 2. Cost Analysis for SCR

Capital Cost	Turbine	OAQPS Notation[1]	Notes
Purchased Equipment Costs			
Equipment Cost	574,100		From Budget Costs from FERCO October 2013 Quote - SCR Equipment minus CEMS cost.
Instrumentation[3]	57,410	0.10 × A	
Sales Tax[3]	22,964	0.04 × A	
Freight[3]	28,705	0.05 × A	
Total Purchased Equipment Costs	*683,179*	*B*	
Direct Installation Costs			
Commissioning	*354,544*		From Budget Costs from FERCO October 2013 Quote. Total commissioning cost is ratioed based on the cost of the SCR equipment.
Total Direct Costs	1,037,723	*D = B + C*	
Indirect Installation Costs [4]			
General Facilities	51,886	0.05 x D	
Engineering and Home Office Fees	103,772	0.10 x D	
Process Contingency	51,886	0.05 x D	
Total Indirect Installation Costs	*207,545*	*E*	
Continuous Emission Monitor, CEMs [5]	0		Assuming no CEMS
Project Contingency [4]	186,790	G = 0.15 × (D + E + F)	
Total Capital Investment	**1,432,058**	**TCI = D + E + F + G**	

Operating Cost	Turbine	OAQPS Notation	
Direct Annual Costs			
Operating Labor[6]	16,425	H	Currently assuming 0.5 hours per shift with 3 shifts per day.
Maintenance Labor[6]	16,425	I	
Supervisory Labor[6]	2,464	J = 0.15 x H	
Maintenance Materials[6]	16,425	I	
Utilities - Natural Gas[7]	87,554	Calculated	Refer to Table 1
Utilities - Electricity[8]	95,997	Calculated	Refer to Table 2
Utilities - Aqueous Ammonia[9]	11,658	Calculated	Refer to Table 3
Catalyst Replacement[10,12]	8,307	Calculated	Refer to Table 4
Catalyst Disposal[11]	2,225	Calculated	Refer to Table 5
CEM Annual Cost[5]	0		Assuming no CEMS
Total Direct Annual Costs	*257,480*	*DAC*	
Indirect Annual Costs			
Overhead[14]	0		
Administrative Charges[14]	0		
Property Taxes[14]	0		
Insurance[14]	0		
Capital Recovery on Total Capital Investment[12]	135,176		
Total Indirect Annual Costs	*135,176*	*IDAC*	
Total Annual Cost [13]	**392,656**	*TAC = DAC + IDAC*	
Pollutant Removed (tpy)	8.96		
Cost per ton of NO_X Removed	**43,805**	*$/ton = TAC / Pollutant Removed*	

1. U.S. EPA OAQPS, *EPA Air Pollution Control Cost Manual (6th Edition)* , January 2002, Section 4.2, Chapter 2.
2. Estimated value based on previous BACT analysis experience.
3. Based on general OAQPS costs as presented on page 2-27 of Section 1, Chapter 2 of OAQPS Manual.
4. Based on costs as presented in Table 2.5 on page 2-44 of Section 4.2, Chapter 2 of OAQPS Manual.
5. Based on EPA CEM Cost Model, Version 3.0 dated March 7, 2007 from previous BACT analysis experience.
6. Operator and maintenance labor based on $30/hr x 0.5 hrs/shift x 3 shifts per day (1,095 shifts/yr). It is assumed that the cost of maintenance materials is equal to the cost of maintenance labor.
7. Calculated as Loss % x MMBtu/hr x hr/yr x $/MMBtu
8. Calculated as Loss % x kW x hr/yr x $/kW + (Ammonia Vaporizer Cost $/hr + Dilution Blower Cost $/hr) x 8760 hr/yr.
9. Calculated as aqueous ammonia ton/yr x $/ton.
10. The cost of catalyst replacement includes the cost of catalyst replacement plus sales tax and freight.
11. Catalyst disposal cost calculated as disposal cost ($/ft^3) x kW / (1000 kW / MW) x (6180 ft^3 / 83 MW).
12. Capital Recovery calculated based on Equations 2.54 and 2.55 of OAQPS Manual, Section 4.2, Chapter 2, pages 2-48 and 2-49. (Annual cost = capital cost x capital recovery factor).
13. Based on OAQPS, Section 4, Chapter 2, p. 2-49 http://www.epa.gov/ttn/catc/dir1/cs4-2ch2.pdf
14. Based on OAQPS, Section 4, Chapter 2, p. 2-48, assume that overhead costs, administrative charges, property taxes, and insurance are negligible: http://www.epa.gov/ttn/catc/dir1/cs4-2ch2.pdf

Table 3 Facility-Wide Cost Information

Parameter	Value	Units	Reference	Notes
Operating Labor Cost	30	$/hr		
Maintenance Labor Cost	30	$/hr		
Electricity Cost	0.1304	$/kW-hr	2	
Natural Gas Cost	11.34	$/1,000 scf	3, 8	
Ammonia Soln Cost	0.15	$/lb	6, 8	
Reagent (Ammonia) Cost	1.12	$/gal	7	

Consumer Price Indices

Year	Value	Units	Reference	Notes
2015 $ (July)	238.7		1	
2014 $ (Average)	236.7		1	
2010 $ (November)	218.8		1	
2010 $ (March)	217.6		1	
2004 $	188.9		1	
2002 $	179.9		1	
1999 $	166.6		1	
1998 $ (December)	163.9		1	
1998 $ (2nd Quarter)	163.0	June 1998 $	1	
1997 $ (March)	160.0		1	
1995 $ (3rd Quarter)	153.2	Sept 1995 $	1	
1991 $ (September)	137.2		1	
1987 $ (2nd Quarter)	113.5	June 1987 $	1	

1. U.S. Historical Consumer Price Index: ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt.
2. Industrial June 2015 electricity cost for MA:
http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a
3. Industrial natural gas cost obtained from U.S. Energy Information Administration for 2014 for MA:
http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SMA_a.htm
4. Based on OAQPS, Section 6, Chapter 1 p.1-48
5. Based on Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization. Lime ranges from $60 to $80 per ton. Used $60 per ton and adjusted to 2013 values: http://www.epa.gov/ttn/catc/dir1/ffdg.pdf
6. Based on OAQPS, Section 4, Chapter 2, p. 2-50, for 29% ammonia solution. http://www.epa.gov/ttn/catc/dir1/cs4-2ch2.pdf.
7. Calculated from ammonia solution cost, using the density of aqueous ammonia. Density ranges from 7.46 - 7.71 lbs/gal per MSDS from Tanner Industries: http://www.tannerind.com/aqua-msds.html
8. Converted to July 2015 value based on the Consumer Price Index.

Inputs		
CO_2 Emissions from Source	35568	Short Tons per Year [a]
Distance to Infrastructure	180	Miles [b]
Project Life	30	Years [c]
Capture Efficiency	90%	[d]

a CO_2 emissions based on process design requirements and emission calculations. Source: \\10.21.1.2\Projects\Client\Boston Office\CLIENTS\Spectra Energy\Atlantic Bridge\Permitting\MA - Weymouth\04 Projects\142201.0010 - AB Weymouth\02 Info from Client

b Distance from the Chaplin compressor station to the nearest potential CO_2 sequestration facility, conservatively assuming the shortest distance as the pipeline route.

c Project life set by engineering judgement. The National Energy Technology Laboratory (NETL) quality guidance documents also use 30 years as a project life.

d Capture efficiency of 90% is assumed by NETL's Estimating Carbon Dioxide Transport and Storage Costs (p. 9)

Volumetric Flow Measurements			
TOTAL - MASS	35,568	tpy CO_2	
CAPTURE EFF.	90%		3,557
CAPTURED - MASS	32,011	tpy CO_2	
Density of CO_2 - Metric (MIT)[e]	884	kg/m^3	
Density of CO_2 - English	0.0276	tons / acf	
TRANSPORT VOLUME	1.16	MMacf/yr CO_2	

e Density of CO_2 taken from Carbon Capture and Sequestration Technologies Program Massachusetts Institute of Technology. Carbon Management GIS: CO2 Pipeline Transport Cost Estimation. October 2006, Updated in June 2009. (p. 4)

kg per tons conversion	907.185
ft3 per m3 conversion	35.3147

Weymouth	CO2	
Turbine	**35,568**	
	35,568	
	97	***tpd rate***

Summary Table: Pipeline and Class VI Well		
Pipeline Cost - NETL	$428	/ton
Storage Cost - NETL	$175	/ton
Capture Cost [1]	$107	/ton
TOTAL COSTS [2]	**$709**	/ton

1 Based on the 2010 CCS Task Force Report, the cost factor for post-combustion capture of CO_2 from a NGCC system is selected because it is the most similar process with available cost information to that of the proposed project. Note that the Approximate Cost Factor (ACF) for capturing the CO_2 from the turbines also includes the cost for compressing the CO_2 for transport in pipelines. Monthly data from the Producer Price Index (PPI) is used to convert December 2009 dollars (PPI = 175.1) to June 2015 dollars (PPI = 196.9) (support activities for oil and gas operations, series ID# 213112213112). PPI obtained from the Bureau of Labor Statistics website at www.bls.gov.

2 All costs are presented in present value using the Producer Price Index to calculate the change in currency value.

Diameter Estimation for CO_2 Transport Pipeline

Method from "Carbon Management GIS: CO2 Pipeline Transport Cost Estimation"
published by the Carbon Capture and Sequestration Technologies Program,
Massechusetts Institute of Technology
October 2006, Updated June 2009

Input		
CO2 Mass Flow Rate	0.03	Metric Megatons per Year

Lookup Table			
Pipeline Diameter Inches	Maximum Mass Flow Rate[1] Metric Megatons per Year	Sufficient?	Sufficiently Sized Pipes Inches
4	0.19	TRUE	4
6	0.54	TRUE	6
8	1.13	TRUE	8
12	3.25	TRUE	12
16	6.86	TRUE	16
20	12.26	TRUE	20
24	19.69	TRUE	24
30	35.16	TRUE	30
36	56.46	TRUE	36

Output		
Pipeline Diameter:	4	Inches

[1] From source document, assuming transport conditions of 25 °C and 158 bar.

metric ton per short ton conversion	0.907185
metric ton per metric mega ton conversion	1000000

Cost Estimation for Transfer of CO_2 via Pipeline - SOURCE TYPES AND EU IDS

Source Document: "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	180.0	miles
Average Diameter of Pipeline	4	inches
CO_2 emissions from **Source**	35,568	Short tons/yr
CO_2 Capture Efficiency	90%	
Captured CO_2	32,011	Short tons/yr

CO_2 Transfer Cost Estimation [1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs, Present Value ($)			
Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)	$11,717,900.40
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$61,547,093.60
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$11,782,694.80
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$6,980,773.00
Related Capital Expenditures, Present Value ($)			
CO_2 Surge Tank	$	$1,150,636	$1,150,636.00
Pipeline Control System	$	$110,632	$110,632.00

Variable Operation & Maintenance (O&M), Annual Basis ($/yr)			
Fixed O&M	$/mile/yr	$8,632	$1,553,760.00

Amortized Cost Calculation

Equipment Life [2]	30	years
Interest rate [3]	7%	
Capital Recovery Factor (CRF) [4]	0.08	(years)$^{-1}$
Total of Pipeline Present-Value Costs (TCI)	$93,289,730	$ (Pipeline + Other Capital)
Amortized Present-Value Cost (TCI *CRF)	$7,517,884	$/yr
Amortized Present-Value + O&M Cost	**$9,071,644**	**$/yr**
CO_2 Transferred	32,011	Short tons/yr
Annuitized control cost per ton [5]	**283.39**	**$/ton**
Producer Price Index [6] June 2007	**113.50**	**$**
July 2015	**171.4**	**$**
Annuitized control cost per ton - 2015 Dollars [5]	**427.96**	**$/ton**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

[2] Pipeline life is assumed based on engineering judgment. The National Energy Technology Laboratory (NETL) quality guidance documents also use 30 years as a project life.

[3] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.

[4] Capital Recovery Factor = Interest Rate (%) x (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)

[5] This cost estimation does not include capital and O&M costs associated with necessary compression or processing equipment pre-pipeline.

[6] The ratio of the producer price index (other pipeline transportation, series ID# 4869) of August 2015 to June 2007 is used to estimate costs in present dollars. PPI obtained from the Bureau of Labor Statistics website at www.bls.gov.

Cost Estimation for Storage of CO_2 - SOURCE TYPES AND EU IDS

Source Document: "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Captured CO_2	32,011	Short tons/yr
Number of Injection Wells [1]	1	
Injection Well Depth [1]	1,236.00	meters

CO_2 Transfer Cost Estimation [1]

Cost Type	Units	Cost Equation	Cost ($)
Capital Costs			
Site Screening and Evaluation	$	$4,738,488	$4,738,488.00
Injection Wells	$ / well	$240,714 x e ^ (0.0008 x meters depth)	$647,040.90
Injection Equipment	$ / well	$94,029 x (7,389 / (280 x # wells)) ^0.5	$483,031.70
Liability Bond	$	$5,000,000	$5,000,000.00
Declining Capital Funds			
Pore Space Acquisition	$ / ton CO_2	$0.334 / ton CO_2	$320,750.22
Fixed Operation & Maintenance (O&M), Annual Basis			
Normal Daily Expenses (Fixed)	$/well/day	$11,566	$4,221,590.00
Surface Maintenance (Fixed)	$	$23,478 x (7,389 / (280 x # wells)) ^.5	$120,607.67
Subsurface Maintenance (Fixed)	$/well/ft-depth	$7.08	$28,710.24

Variable Operation & Maintenance (O&M), Annual Basis			
Consumables (Variable)	($/yr) / (tons CO_2/day)	$2,995	$262,665.60

Amortized Cost Calculation

Equipment Life [2]		30	years
Interest rate [3]		7%	
Capital Recovery Factor (CRF) [4]		0.08	$(years)^{-1}$
Total Storage Installation Cost (TCI)		$11,189,311	$ (Installation + Fixed O&M)
Amortized Installation Cost (TCI *CRF)		$901,706	$/yr
Amortized Installation + O&M Cost		**$5,535,280**	**$/yr**
CO_2 Transferred		32,011	Short tons/yr
Annuitized control cost per ton [5]		**173**	**$/ton**
Producer Price Index [6]	**June 2007**	**194.90**	**$**
	July 2015	**196.9**	**$**
Annuitized control cost per ton - 2015 Dollars [5]		**174.69**	**$/ton**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

[2] Pipeline life is assumed based on engineering judgment.

[3] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.

[4] Capital Recovery Factor = Interest Rate (%) x (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)

[5] This cost estimation does not include capital and O&M costs associated with processes upstream of storage.

[6] The ratio of the producer price index (support activities for oil and gas operations, series ID# 213112) of August 2015 to June 2007 is used to estimate costs in present dollars. PPI obtained from the Bureau of Labor Statistics website at www.bls.gov.

feet per meter conversion 3.28084

ATTACHMENT F: NOISE SURVEY REPORT

WEYMOUTH COMPRESSOR STATION
(NORFOLK COUNTY, MASSACHUSETTS)

RESULTS OF ADDITIONAL AMBIENT SOUND SURVEY AND UPDATED ACOUSTICAL ANALYSIS OF A NEW NATURAL GAS COMPRESSOR STATION ASSOCIATED WITH THE PROPOSED ATLANTIC BRIDGE PROJECT (“AB PROJECT”)

H&K Report No. 3513

H&K Job No. 4818

Date of Report: January 11, 2017

Prepared for: **Algonquin Gas Transmission, LLC** (“Algonquin”)
890 Winter Street, Suite 300
Waltham, MA 02451

Submitted by: Paul D. Kiteck, P.E. (primary author)
Hoover & Keith, Inc. (H&K)

Hoover & Keith Inc.
Consultants in Acoustics and Noise Control Engineering
TX Office: 11381 Meadowglen, Suite I; Houston, TX 77082 TX Office Phone: (281) 496-9876
CO Office: 1680 Northwestern Road; Longmont, CO 80503 CO Office Phone: (303) 834-9455

REPORT SUMMARY

This report includes the results of an updated acoustical analysis for the Weymouth Compressor Station (abbreviated as "Station" in this report), a grass roots natural gas compressor station associated with the Atlantic Bridge Project ("Project" or "AB Project") for Algonquin Gas Transmission, LLC ("Algonquin"). The purpose of the updated acoustical analysis is to include the estimated sound level of the Station at the Station property line and compare to applicable sound criterion. For completeness, included in the report is the previously reported Station acoustical analysis for identified NSAs and for receptors recommended by the Massachusetts Energy Facilities Siting Board ("Siting Board") along with an assessment of the noise increases for both nighttime and daytime levels at the NSAs/receptors, based on the lowest ambient levels.

The following table summarizes the ambient sound level at the Station site (i.e., ambient L_{dn}), the estimated sound contribution of the Station during full load operation at the receptors/NSAs and the "total" cumulative sound level at the NSAs (i.e., Station sound level plus the ambient sound level). The results in this table are defined as the "Noise Quality Analysis" for the Station.

Noise Quality Analysis for the Weymouth Compressor Station associated with the AB Project

Identified Receptor/NSA and Type of Receptor/NSA	Distance & Direction of Receptor/NSA	Ambient Ldn (dBA)	Est'd Sound Level (Ldn) of Station at Full Load (dBA)	Est'd Station Sound Level (Ldn) + Ambient Ldn (dBA)	Increase above Ambient Ldn (dB)
NSA #1 (Residences)	610 feet (SSE)	70.4	49.0	70.4	0.0
NSA #2 (Residences)	1,370 feet (north)	54.9	42.1	55.1	0.2
NSA #3 (Residences)	1,560 feet (east)	54.0	40.8	54.2	0.2
NSA #4 (Residences)	900 feet (south)	56.5	45.3	56.8	0.3
NSA #5 (Residences)	1,030 feet (SE)	64.3	43.9	64.3	0.0
NSA #6 (Residences)	2,300 feet (SE)	50.6	35.7	50.7	0.1
NSA #7 (Residences)	1,970 feet (ENE)	49.1	38.2	49.4	0.3
NSA #8 (Residences)	2,400 feet (west)	52.6	35.3	52.7	0.1
NSA #9 (School)	4,200 feet (ESE)	49.8	29.1	49.8	0.0

The acoustical analysis presented in this report indicates that the noise attributable to the Weymouth Compressor Station is estimated to be lower than **55 dBA** (L_{dn}) at all surrounding receptors/NSAs. Consequently, the noise generated by the Station should meet the anticipated FERC sound level requirement for the Station. In addition, the results of the acoustical analysis indicates that the Station sound contribution should also meet the MassDEP noise requirements at the Station property line, as well as the MassDEP noise guideline for pure tone noise condition. The noise generated by the Station should have minimum noise impact at the surrounding receptors/NSAs, even during nighttime Station operation. It should be noted that very stringent and proven noise control measures will be employed at this Station to meet the FERC level sound requirement and other Commonwealth of Massachusetts/township noise standards.

TABLE OF CONTENTS

1.0 INTRODUCTION

An acoustical analysis report for the Weymouth Compressor Station, a grass roots natural gas compressor station associated with the proposed Atlantic Bridge Project ("AB Project" or "Project") for Algonquin Gas Transmission, LLC ("Algonquin"), was previously filed with the Federal Energy Regulatory Commission as part of Resource Report 9 of the AB Project Certificate Application. In this report, Hoover & Keith Inc. (H&K) presents the results of an updated acoustical analysis for the Weymouth Compressor Station. The purpose of the updated acoustical analysis is to include the estimated sound level contribution of the Station at the closest Station property line and compare to applicable sound criterion. For completeness, included in the report is the previously reported Station acoustical analysis (i.e., H&K Report No. 3316[1]) for identified noise-sensitive areas (NSAs) and for receptors recommended by the Massachusetts Energy Facilities Siting Board ("Siting Board") along with an assessment of the noise increases for both nighttime and daytime levels at the NSAs/receptors, based on the lowest ambient levels. The following summarizes the information included in the report:

- Document existing acoustic environment and identify nearby NSAs, such as residences, schools, hospitals and other receptors, around the Station including additional receptors recommended by the Siting Board.
- Estimated sound contribution of the Station at the surrounding receptors/NSAs and closest Station property line including an expanded noise analysis for receptors recommended by the Siting Board (i.e., assessment of the noise increases for both nighttime and daytime levels, based on the lowest ambient levels).
- Determine noise control measures and discuss noise mitigation practices to insure that applicable sound criteria are not exceeded due to the operation of the Station.
- Project the noise resulting from construction activities at the site of the Station and estimate the noise contribution due to a compressor unit blowdown event; and address noise-related comments/requests by the Siting Board regarding the Weymouth Compressor Station[2].

2.0 DESCRIPTION OF STATION SITE AND EQUIPMENT

Figure 1 (**Appendix**, p. 16) is an area layout around the Station site showing the nearby NSAs (i.e., primarily residences) within ½ mile of the Station, the location of the identified NSAs-receptors and reported sound measurement positions near the identified NSAs. **Figure 2** (**Appendix**, p. 17) show a conceptual layout of Station buildings, equipment, area of

---

[1]H&K Report No. 3316, dated 10/5/15, entitled "Weymouth Compressor Station: Results of the Most Recent Ambient Sound Survey and Updated Acoustical Analysis…associated with the AB Project"

[2]Siting Board comments/requests were included in letters sent via electronic filing to FERC, dated July 24, 2015 and June 18, 2015 (Re: Algonquin Gas Transmission, L.L.C, PF15-12-000), in advance of FERC's preparation of EA.

aboveground piping and Station property line. The Station will be located in Norfolk County, Massachusetts, within the city limits of Weymouth (MA), just on the North Side of Bridge Street. There is an existing Algonquin natural gas meter station (i.e., "Weymouth Meter Station"), and the MWRA Pumping Station located in the same general area as the Station site. The Station will be equipped with one (1) Solar Model Taurus 60 turbine-driven compressor unit [ISO horsepower (HP) of 7,700 HP]. The turbine and compressor will be installed in an acoustically-insulated metal building ("Compressor Building"), which will be constructed of a brick façade. The following describes the auxiliary equipment and other notable items associated with the Station.

- Turbine exhaust system, which includes a silencer system and exhaust stack;
- Turbine air intake filter system that includes an in-duct intake silencer system;
- Outdoor lube oil cooler ("LO cooler") that serves the compressor unit;
- Aboveground gas piping and associated components (e.g., valves, suction filter separators);
- Outdoor gas aftercooler that serves the Station compressor unit; and
- Courtyard barrier/walls will be employed between the Compressor Building and Auxiliary Building; as a result, the gas aftercooler and aboveground piping in the area of the Compressor Building will be located inside a "courtyard area".

In addition, there will be a gas blowdown vent for the compressor unit at the "Source Control", within the fenced area of the Station (defined as the "unit blowdown" via a "case vent separator"), in which natural gas between the suction/discharge valves and compressor is vented to the atmosphere via a blowdown silencer. During commissioning, a unit blowdown could occur 3 or 4 times/day and only during the daytime. During normal Station operation (i.e., after commissioning), a unit blowdown event occurs infrequently (e.g., 2 to 3 times/month) and only for a short time frame (e.g., unit blowdown persist for approximately 1 to 5 minutes). The Station also includes an emergency shutdown ("ESD") that will only occur at required DOT test intervals (e.g., annual test of blowdown system) or in an emergency situation (gas leak or fire), and we understand that an ESD blowdown, if necessary, occurs for less than five (5) minutes.

3.0 <u>SOUND LEVEL CRITERIA</u>

3.1 Federal (FERC) Sound Requirement: The Office of Energy Projects (OEP) of the Federal Energy Regulatory Commission (FERC) requires that the sound attributable to a natural gas compressor station not exceed the day-night average sound level (i.e., L_{dn}) of **55 dBA** at any nearby NSA. In addition, **55 dBA** (L_{dn}) is used as a "guideline" for assessing the noise impact of temporary or intermittent noise such as construction noise or noise of a blowdown event. The L_{dn} is an energy average of the equivalent A-weighted ("A-wt.") sound level ("L_{eq}") during the daytime ("L_d") and the nighttime L_{eq} ("L_n") plus **10 dB**. For a steady sound source that operates over a 24-hour period and controls the environmental sound level, the L_{dn} is approximately **6.4 dB** above the measured L_{eq}. As a result, an L_{dn} of **55 dBA** corresponds to a L_{eq} (e.g., L_d) of **48.6 dBA**. If both the L_d and L_n are measured, then the L_{dn} is calculated using the following formula:

$$L_{\mathrm{dn}} = 10\log_{10}\left(\frac{15}{24}10^{L_{\mathrm{d}}/10} + \frac{9}{24}10^{(L_{\mathrm{n}}+10)/10}\right)$$

3.2 State, County and/or Local Noise Regulations

Commonwealth of Massachusetts: The following policy was adopted by the Division of Air Quality Control ("DAQC") for The Commonwealth of Massachusetts, which is intended to enforce and provide a guideline for the current noise regulation (i.e., 310 CMR Section 7.10). DAQC's Policy 90-001, as stated by Barbara Kwetz (DAQC Acting Director) on Feb. 1, 1990 is as follows:

A source of sound will be considered to be violating the Massachusetts Department of Environmental Protection ("MassDEP") noise regulation (310 CMR 7.10) if the source:

1. Increases the broadband sound level by more than **10 dB** above ambient (referred to as the "10 dBA above ambient limit"), or
2. Produces a "pure tone" condition—when any O.B. center frequency sound pressure level exceeds the two adjacent center frequency sound pressure levels by **3 decibels** or more.

These criteria are measured both at the property line and at the nearest inhabited residence. The "ambient" is defined as the lowest background A-wt. sound level that is exceeded 90% of the time ("L_{90}"). Although not stated, it is assumed that the "pure tone" condition includes the O.B. SPLs of 31.5 Hz to 8000 Hz. The ambient may also be established by other means with the consent of the Department. Based on the reported lowest background sound level (i.e., nighttime L_{90}), the DAQC A-wt. noise guideline for the identified NSAs is greater than the FERC sound level requirement. Consequently, in general, if the FERC sound level requirement is achieved, which will be required by the FERC, the DAQC A-wt. noise limit should also be attained.

Town of Weymouth: There is a Weymouth Regulation #17 (RE: MGL Chapter 111 Section 31 and Section 122, adopted by Board of Health), related to nuisances. In our opinion, if the Station sound level meets the DAQC noise guideline, the noise-related condition in the Regulation will be achieved (i.e., "noise over **10 dB** over ambient background" is considered a nuisance).

4.0 MEASUREMENT METHODOLOGY, CONDITIONS, SOUND MEASUREMENT LOCATIONS

4.1 Measurement Methodology and Conditions

Sound surveys at the identified NSAs/receptors was performed by Garrett Porter of H&K during the daytime and nighttime of August 14, 2015 and nighttime sound tests were conducted between 12:00 PM and 4:00 AM (i.e., considered by the Siting Board as the most typical quiet hours). During the nighttime tests, there was no construction activities at the Fore River Bridge related to the current Fore River Bridge Replacement Project. Additional sound surveys were conducted by Garrett Porter during daytime and nighttime on Sept. 8 & 9 (2016) around the Station property line, which were not performed during the August (2015) sound surveys.

At each sound measurement location, the ambient L_d, L_n and nighttime L90 and associated unweighted octave-band (O.B.) sound pressure levels (i.e., L_{eq} SPLs and L90 SPLs) were measured at 5 feet above the ground. Periodic samples of the ambient noise level were typically performed at the sound measurement positions. To measure ambient sound levels that are representative of "long-term average" ambient levels, the sound measurements attempted to exclude "extraneous sound" such as a vehicle passing immediately by the sound measurement location or other intermittent sources. The acoustical measurement system consisted of a Norsonic Model Nor140 Sound Level Meter (a Type 1 "SLM" per ANSI S1.4 & S1.11) equipped with a ½-inch condenser microphone with a windscreen. The SLM was calibrated with a microphone calibrator that was calibrated within 1 year of the sound test date.

4.2 Description of Sound Measurement Locations and Receptors/NSAs

During the 2015 sound surveys, ambient levels were measured at the identified closest NSAs (i.e., primarily residences) within each cardinal direction of the Station along with other "receptors" in which a noise analysis impact was requested by the Siting Board. Consequently, there are a total of nine (9) "identified receptors/NSAs" [i.e., closest NSA ("NSA #1") plus 8 other receptors designated by the Siting Board]. The following is a description of the identified receptors-NSAs and chosen sound measurement positions near the receptors/NSAs:

Pos. 1: "NSA #1" (considered the "closest NSA"); Residences located on the North Side of Bridge Street, in Weymouth, approximately 610 feet south-southeast (SSE) of the Station site "acoustic center" (i.e., anticipated location of Compressor Building).
Pos. 2: "NSA #2"; Residences at the end of Saint German St. (area of Germantown Point; Town of Quincy), approximately 1,370 feet north of the Station site center.
Pos. 3: "NSA #3"; Residences located along Kings Cove Beach Road (near Hunt Hills Point, Weymouth), approximately 1,560 feet east of the Station site center.
Pos. 4: "NSA #4"; Residences located near the intersection of Monatiquot Street and Vaness Road (Weymouth), approximately 900 feet south of the Station site center.
Pos. 5: "NSA #5"; Residences located along Kings Cove Way (Weymouth), approximately 1,030 feet southeast (SE) of the Station site center.
Pos. 6: "NSA #6"; Residences located in the area of Roslind Road and Evans Road (Weymouth), approximately 2,300 feet SE of the Station site center.
Pos. 7: "NSA #7"; Residences located in the area of Weybosset Street and Fore River Ave. (Weymouth), approximately 1,970 feet east-northeast (ENE) of the Station site center.
Pos. 8: "NSA #8"; Residences located along Dee Road (Quincy), approximately 2,400 feet west of the Station site center.
Pos. 9: "NSA #9"; Johnson School (Pearl Street, Weymouth), located approximately 4,200 feet east-southeast (ESE) of the Station site center.

For the 2016 sound surveys [around the Station property line ("PL")], sound tests were conducted at the north PL (i.e., Meas. Pos. B), West PL (i.e., Meas. Pos. C), south PL (i.e., Meas. Pos. D) and the east PL (i.e., Meas. Pos. A; closest PL to Station site center and adjacent to "King's Cove Park–Conservation Area").

5.0 MEASUREMENT RESULTS AND OBSERVATIONS

The following summarizes the sound data tables included in the **Appendix** of the report that provide the results of the sound surveys:

- **Table 1** (**Appendix**, p. 18) summarizes the measured L_d, L_n, daytime L90 and nighttime L90 at NSA sound measurement positions along with the resulting ambient L_{dn}.
- **Table 2** (**Appendix**, p. 18) provides meteorological conditions during 2015 sound surveys.
- **Table 1A** (**Appendix**, p. 19) summarizes the measured L_d, L_n, measured daytime L90 and nighttime L90 at the PL sound measurement positions (2016 sound surveys).
- **Table 2A** (**Appendix**, p. 19) provides meteorological conditions during 2016 sound surveys.
- **Table 3** (**Appendix**, p. 20) includes the measured daytime A-wt. sound levels (L_d) and unweighted O.B. SPLs at the NSA sound measurement positions;
- **Table 4** (**Appendix**, p. 21) includes the measured nighttime A-wt. sound levels (L_n) and related unweighted O.B. SPLs at the NSA sound measurement positions;
- **Table 5** (**Appendix**, p. 22) includes the measured daytime L_{90} and related unweighted O.B. L_{90} SPLs at the NSA sound measurement positions.
- **Table 6** (**Appendix**, p. 23) includes the measured nighttime L_{90} and related unweighted O.B. L_{90} SPLs at the NSA sound measurement positions.

The following **Table A** summarizes the measured ambient L_d, ambient L_n and resulting L_{dn} (i.e., calculated via the measured L_d and L_n) at the identified receptors/NSAs.

Meas. Position	Identified Receptors/NSAs and Description of Sound Measurement Location near the Respective NSA	Meas'd Ambient Ld (dBA)	Meas'd Ambient Ln (dBA)	Resulting Ambient Ldn (dBA)
Pos. 1	NSA #1: Residences approx. 610 ft. SSE of the Station site center	72.4	46.7	70.4
Pos. 2	NSA #2: Residences approx. 1,370 ft. north of Station site center	50.3	48.1	54.9
Pos. 3	NSA #3: Residences approx. 1,560 ft. east of the Station site center	50.1	46.9	54.0
Pos. 4	NSA #4: Residences approx. 900 ft. south of the Station site center	51.0	49.9	56.5
Pos. 5	NSA #5: Residences approx. 1,030 ft. SE of the Station site center	66.2	42.6	64.3
Pos. 6	NSA #6: Residences approx. 2,300 ft. SE of the Station site center	45.1	44.0	50.6
Pos. 7	NSA #7: Residences approx. 1,970 ft. ENE of the Station site center	46.9	41.3	49.1
Pos. 8	NSA #8: Residences approx. 2,400 ft. west of the Station site center	48.2	45.7	52.6
Pos. 9	NSA #9: Johnson School approx. 4,200 ft. ESE of Station site center	47.0	42.4	49.8

Table A: Summary of the Measured Ambient Ld, Measured Ambient Ln and Resulting Ambient Ldn at the Identified Receptors/NSAs based on the Most Recent Sound Survey, conducted 8/14/15.

The following **Table B** includes the measured daytime L90 and the measured nighttime L90 (considered the "lowest ambient sound level") along with the resulting DAQC A-wt. noise level guideline at the NSAs-receptors and East PL of the Station (i.e., based on "10 dBA above ambient limit" adopted by the MassDAQC).

Meas. Pos.	Identified Receptors/NSAs and Description of Sound Measurement Location near the Respective NSA	Meas'd Daytime L90 (dBA)	Meas'd Nighttime L90 (dBA)	Calc'd DAQC Noise Limit (dBA)
Pos. 1	NSA #1: Residences approx. 610 ft. SSE of the Station site center	66.4	44.8	54.8
Pos. 2	NSA #2: Residences approx. 1,370 ft. north of Station site center	46.8	46.8	56.8
Pos. 3	NSA #3: Residences approx. 1,560 ft. east of the Station site center	48.4	44.0	54.0
Pos. 4	NSA #4: Residences approx. 900 ft. south of the Station site center	49.3	48.5	58.5
Pos. 5	NSA #5: Residences approx. 1,030 ft. SE of the Station site center	55.1	41.3	51.3
Pos. 6	NSA #6: Residences approx. 2,300 ft. SE of the Station site center	42.6	41.4	51.4
Pos. 7	NSA #7: Residences approx. 1,970 ft. ENE of the Station site center	44.5	39.3	49.3
Pos. 8	NSA #8: Residences approx. 2,400 ft. west of the Station site center	46.1	44.5	54.5
Pos. 9	NSA #9: Johnson School approx. 4,200 ft. ESE of Station site center	43.3	41.0	51.0
Pos. A	East PL of Station (area of King's Cove Park/Conservation Area)	47.8	49.5	57.8

Table B: Summary of Measured Ambient Daytime L90 (i.e., "Lowest Ambient Daytime Level") and Ambient Nighttime L90 (i.e., "Lowest Ambient Level") at the Identified Receptors/NSAs and Calculated DAQC Noise Limit based on the Lowest Ambient Level.

In our opinion, the measured ambient sound data adequately quantifies and is representative of the existing ambient environment at the identified receptors/NSAs for the meteorological conditions that occurred during the sound surveys.

During the <u>daytime</u> ambient sound measurements near the NSAs, the audible noise sources that contributed to the measured ambient A-wt. sound level included primarily the noise of vehicle traffic (primarily traffic along Bridge Street), noise of industrial activity (e.g., noise of Power Plant and other industrial facilities in the area), and at times, some sound of insects and the noise of small boats in the river and waterways.

During the <u>nighttime</u> ambient sound measurements near the NSAs, the audible noise sources that contributed to the measured ambient A-wt. sound level included the noise of distant vehicle traffic (noise of traffic notably lower than during the daytime), the noise of industrial activity in the area, and at times, the sound of insects. Note that at the Station property line, it is possible that daytime ambient levels can be higher than nighttime ambient levels due to the type of environmental noise sources that influence the measured ambient levels.

Note that there was <u>no construction activities</u> at the Fore River Bridge, as related to the Fore River Bridge Replacement Project, during the nighttime sound tests. In addition, the noise of construction activities at the Fore River Bridge during the daytime sound measurements did not appear to be a significant noise contributor to the daytime A-wt. sound levels since the noise of traffic along Bridge Street was the dominant noise contributor during the daytime sound tests.

6.0 NOISE IMPACT ANALYSIS (COMPRESSOR STATION)

The following section addresses the potential noise impact due to the full load operation of the Station at the identified receptors/NSAs. Also included is a noise assessment of the noise associated with a unit blowdown that occurs occasionally and a discussion of perceptible vibration during Station operation. The noise contribution of the Station at more distant NSAs should be lower than the predicted noise level at the identified receptors/NSAs.

6.1 Sound Contribution of the Station

The acoustical analysis considers the noise produced by all continuously-operated equipment that could impact the sound contribution at the identified nine (9) receptors/NSAs. The following sound sources associated with the Station compressor installation were considered significant.

- Noise generated by the turbine/compressor that penetrates the Compressor Building.
- Noise of the turbine exhaust (primary noise source that could generate perceptible vibration).
- Noise radiated from aboveground gas piping and associated components.
- Noise of the outdoor LO cooler.
- Noise generated by the turbine air intake system.
- Noise of the outdoor gas aftercooler.

For this acoustical analysis, the sound contribution of the Station was estimated for the identified receptors/NSAs along with the total cumulative sound level at the receptors/NSAs [i.e., Station sound level contribution plus the measured ambient L_{dn} or the "lowest ambient sound level" (daytime or nighttime L90)]. A description of the acoustical analysis methodology and source of sound data are provided in the **Appendix** (pp. 30–31). The acoustical analysis includes the effect of anticipated noise mitigation measures for the Station/equipment, as described in more detail in **Section 8.0**.

For those receptors in which there is mostly land between the receptor and Station (i.e., NSA #1, NSA #4, NSA #5, NSA #6, NSA #8 & NSA #9), **Tables 7–12** (**Appendix**, pp. 24–26) provide the spreadsheet calculation of the estimated A-wt. sound level and unweighted O.B. SPLs at the respective NSA contributed by the Station if operated at full load. Also the total cumulative sound level at the respective NSA is estimated in these tables (i.e., Station sound level plus the lowest ambient sound level or ambient L_{dn}). The spreadsheet analyses in **Tables 8–12** are based on the estimated Station sound level contribution at NSA #1 (i.e., **Table 7**), which is the closest NSA.

For those receptors in which there is a large body of water (e.g., Kings Cove or Weymouth Fore River) between the receptor and the Station (i.e., NSA #2, NSA #3 & NSA #7), the acoustical analysis in **Tables 13–15** (**Appendix**, pp. 27–28) includes the estimated noise impact of the Station noise traveling over water along with the total cumulative sound level. The spreadsheet analyses in **Tables 14** & **15** are based on the estimated Station sound contribution at NSA #2 (i.e., **Table 13**), which is the closest NSA with a large water body between the Station and receptor. The Station sound contribution for these NSAs were analyzed separately to address comments regarding the impact of Station noise traveling over a large body of water. The acoustical analysis methodology related to noise dispersion over water is discussed in more detail in the "description of the acoustical analysis methodology" (i.e., **Appendix**).

The following **Table C** summarizes the estimated A-wt. sound level contribution of the Station at the identified receptors/NSAs assuming full load operation of Station equipment along with the resulting L_{dn} of the Station, based on the estimated A-wt. sound level contribution.

Location (Receptor/NSA) and Operating Condition	Estimated A-Wt. Sound Level (dBA)	Resulting Ldn (dBA)
Est'd sound level contribution of the Station during full load at NSA #1	42.6	49.0
Est'd sound level contribution of the Station during full load at NSA #2	35.7	42.1
Est'd sound level contribution of the Station during full load at NSA #3	34.4	40.8
Est'd sound level contribution of the Station during full load at NSA #4	38.9	45.3
Est'd sound level contribution of the Station during full load at NSA #5	37.5	43.9
Est'd sound level contribution of the Station during full load at NSA #6	29.3	35.7
Est'd sound level contribution of the Station during full load at NSA #7	31.8	38.2
Est'd sound level contribution of the Station during full load at NSA #8	28.9	35.3
Est'd sound level contribution of the Station during full load at NSA #9	22.7	29.1

Table C: Estimated A-Wt. Sound Level Contribution of the Compressor Station and Resulting Ldn at the Identified Receptors/NSAs during Full Load Operation of the Station

6.2 Noise Impact of the Station compared to Lowest Ambient Daytime/Nighttime Levels

Based on the results of the ambient sound survey and acoustical analyses, the following **Table D** summarizes the measured "lowest ambient daytime levels" at the identified receptors/NSAs (i.e., based on L90 measurements), the estimated sound level contribution of the Station and the estimated noise increase above the lowest daytime levels at the identified receptors/NSAs.

Identified Receptor/NSA and Type of Receptor/NSA	Distance & Direction of Receptor/NSA	Measured Ambient Daytime L90 (dBA)	Est'd A-Wt. Sound Level of the Station at Full Load (dBA)	Est'd Station Sound Level + Ambient Daytime L90 (dBA)	Increase above Lowest Daytime Ambient (dB)
NSA #1 (Residences)	610 feet (SSE)	66.4	42.6	66.4	0.0
NSA #2 (Residences)	1,370 feet (north)	46.8	35.7	47.1	0.3
NSA #3 (Residences)	1,560 feet (east)	48.4	34.4	48.6	0.2
NSA #4 (Residences)	900 feet (south)	49.3	38.9	49.7	0.4
NSA #5 (Residences)	1,030 feet (SE)	55.1	37.5	55.2	0.1
NSA #6 (Residences)	2,300 feet (SE)	42.6	29.3	42.8	0.2
NSA #7 (Residences)	1,970 feet (ENE)	44.5	31.8	44.7	0.2
NSA #8 (Residences)	2,400 feet (west)	46.1	28.9	46.2	0.1
NSA #9 (School)	4,200 feet (ESE)	43.3	22.7	43.3	0.0

Table D: Estimated A-Wt. Sound Level Contribution of the Compressor Station at the Identified Receptors/NSAs and Potential Noise Increase above the Lowest Daytime Levels.

The following **Table E** summarizes the measured "lowest ambient nighttime level" at the identified receptors/NSAs (i.e., based on L90 measurements and considered to be the "lowest ambient level"), the estimated sound level contribution of the Station compared to the established DAQC Noise Limit and estimated noise increase above the lowest ambient level at the receptors/NSAs.

Identified Receptor/NSA and Type of Receptor/NSA	Distance & Direction of Receptor/NSA	Measured Ambient Nighttime L90 (dBA)	Calc'd DAQC Noise Limit (dBA)	Est'd A-Wt. Sound Level of Station (dBA)	Est'd Station Level + Lowest Ambient Level (dBA)	Increase above Lowest Ambient Level (dB)
NSA #1 (Residences)	610 feet (SSE)	44.8	54.8	42.6	46.9	2.1
NSA #2 (Residences)	1,370 feet (north)	46.8	56.8	35.7	47.1	0.3
NSA #3 (Residences)	1,560 feet (east)	44.0	54.0	34.4	44.4	0.4
NSA #4 (Residences)	900 feet (south)	48.5	58.5	38.9	48.9	0.4
NSA #5 (Residences)	1,030 feet (SE)	41.3	51.3	37.5	42.8	1.5
NSA #6 (Residences)	2,300 feet (SE)	41.4	51.4	29.3	41.7	0.3
NSA #7 (Residences)	1,970 feet (ENE)	39.3	49.3	31.8	40.0	0.7
NSA #8 (Residences)	2,400 feet (west)	44.5	54.5	28.9	44.6	0.1
NSA #9 (School)	4,200 feet (ESE)	41.0	51.0	22.7	41.1	0.1

Table E: Estimated A-Wt. Sound Contribution of the Compressor Station at the Receptors/NSAs, as compared to the DAQC Noise Limit, and Noise Increase above the "Lowest Ambient Level".

Consequently, the results provided in **Table E** indicated that the noise generated by the Station should be notably lower than the MassDEP noise requirements. In addition, the results of the acoustical analyses (i.e., **Tables 7–15** in the **Appendix**) indicate the Station noise should meet the MassDEP noise guideline for pure tone noise condition.

Regarding the potential noise impact of the Station at the surrounding receptors/NSAs, if an intruding noise (e.g., noise generated by the Station during operation) causes less than a **3 dB** increase in the overall environmental (ambient) sound level at the receptors (i.e., defined as "increase above ambient level"), the noise generated by the Station should be barely perceivable by the human ear and should have minimum impact on the acoustical environment. As a result, since the estimated increase above the lowest ambient level should be less than **3 dB** at all of the identified receptors/NSAs, even during nighttime Station operation, the noise generated by the Station should have minimum noise impact at the surrounding receptors/NSAs.

6.3 Sound Contribution at Closest Station Property Line and King's Cove Park/Conservation Area

Table 16 (**Appendix**, p. 29) provides a spreadsheet calculation of the estimated A-wt. sound level and unweighted O.B. SPLs during Station operation at the closest Station property limit (i.e., east Station PL), which is adjacent to the "King's Cove Park/Conservation Area". It is assumed that if the noise limits are achieved at the "closest Station property line", then the noise limits will be achieved at other more distant Station property limits.

The following **Table F** summarizes the estimated A-wt. sound level of the Station at the closest Station property limit, lowest ambient L_{90} and the estimated Station sound level above (+) the lowest ambient L_{90} (i.e., based on measured 2016 sound levels at Pos. A, which should be representative of ambient levels in the area of King's Cove Park/Area). The results of **Table F** are presented as a comparison of the most stringent noise limits of the MassDEP (i.e., 10 dBA above ambient limit) to the predicted Station sound level at the closest Station property line.

Location of Closest Station Property Limit	Distance & Direction of Compressor Bldg. to the Property Line	Lowest A-Wt. Ambient L90 (dBA)	A-Wt. Sound Level of the Station (dBA)	Est'd Total A-Wt. Sound Level of Station (dBA)	Station Level above Lowest Ambient L90 (dB)
E. Property Line	Approx. 100 ft. (E)	47.8	53.0	54.2	+5.2

Table F: Estimated A-Wt. Sound Level of the Station at the Closest Station Property Limit (East PL), Lowest Ambient L90, Total Station Sound Level above the Lowest Measured Ambient L90.

The results provided in **Table F** indicate that the Station sound level during operation at the Station property line and in the area of Kings' Cove Park/Conservation Area (i.e., Station east PL) should be lower than the MassDEP (DAQC) noise requirement (i.e., 10 dB above the ambient limit) and should meet the MassDEP noise guideline for pure tone noise condition.

6.4 Perceptible Vibration of the Station Compressor Unit

In general, the noise sources at the Station that could generate "perceptible vibration", such as the noise associated with the turbine exhaust, will be adequately mitigated to insure that the operation of the new compressor unit at the Station will not result in any increase in perceptible vibration (i.e., "direct", or "noise-induced") at any NSA. For clarification, in our opinion, the following defines "direct perceptible vibration" and "noise-induced perceptible vibration":

- "Direct perceptible vibration" is considered to be perceptible <u>groundborne vibration</u> generated by equipment operation (i.e., equipment vibration, which is in contact with the ground, transmitted to and through the ground); in general, the potential groundborne vibration due to the operation of a turbine-driven centrifugal compressor unit should be imperceptible, noting that any ground vibration due to this type of compressor unit during operation should only be perceptible at distances of less than 200 feet from the compressor unit.

- "Noise-induced perceptible vibration" or "<u>airborne vibration</u>" is low-frequency airborne noise that generates perceptible vibration (e.g., "rattling" of windows at a house; vibration of objects inside a house); note that low-frequency noise levels that generate airborne vibration my not be audible by the human ear (i.e., below the threshold for perception of the noise).

<u>Regarding "noise-induced perceptible vibration"</u>, the acoustical analysis (RE: **Table 7**, p. 24) indicates that the low-frequency noise levels generated by the Station (i.e., unweighted O.B. SPL for the 31.5 Hz O.B. & 63 Hz O.B. center frequencies) at the closest NSA will be **63 dB** (31.5 Hz O.B. SPL) and **57 dB** (63 Hz O.B. SPL). Typically, low-frequency noise levels above **65 dB** (e.g., 31.5 Hz O.B. SPL & 63 Hz O.B. SPL) are potentially perceived as noise-induced vibration. Since the predicted low-frequency airborne noise levels at the closest NSAs should be below **65 dB**, there should not be any noise-induced perceptible vibration at any NSA. In conclusion, there

should not result in any increase in perceptible vibration (direct, or noise-induced) at any NSA since Station noise sources that could generate perceptible vibration will be adequately mitigated (i.e., turbine exhaust system will include a 2-stage silencer system).

6.5 Sound Contribution of a Unit Blowdown Event at the Station

The noise of a unit blowdown venting via a blowdown silencer will be specified to meet an A-wt. sound level of **55 dBA** at a distance of 300 feet. If this sound requirement is achieved, the noise of a unit blowdown will be approximately **46 dBA** (i.e., L_{dn} of approximately **52 to 53 dBA**) at the closest NSA (NSA #1), located approximately 700 feet from the blowdown silencer, which would be equal to or lower than **55 dBA** (L_{dn}). Consequently, although the noise of a unit blowdown event could be slightly audible at the nearby NSAs, it is not expected to present a noise impact, noting also that a unit blowdown event occurs infrequently for a short time frame (e.g., 1 to 5 minute period). A description of the acoustical analysis methodology and source of sound data related to blowdown noise are provided in the **Appendix** (p. 31).

7.0 NOISE IMPACT ANALYSIS (SITE CONSTRUCTION ACTIVITIES)

The noise impact analysis of the construction-related activities at the Station site considers the noise produced by any significant sound sources associated with the primary construction equipment that could impact the sound contribution at the nearby NSAs. The predicted sound contribution of construction activities was performed only for the closest NSA (i.e., NSA #1). Construction of the Station will consist of earth work (e.g., site grading, clearing & grubbing) and construction of the site buildings, and the highest level of construction noise would occur during earth work (i.e., period when the largest amount of construction equipment would operate).

Table 17 (**Appendix**, p. 32) shows the calculation of the estimated maximum A-wt. sound level at the closest NSA contributed by the construction activities for standard day propagating conditions. A description of the analysis methodology and source of sound data for the analysis of construction noise are provided in the **Appendix** (p. 33). The acoustical analysis indicates that the maximum A-wt. noise level of construction activities at the closest NSA would be equal to or less than **56 dBA** (L_{dn} of **54 dBA** since nighttime construction activities are not anticipated).

8.0 NOISE CONTROL MEASURES AND EQUIPMENT SOUND REQUIREMENTS

The following section provides recommended noise control measures and equipment sound requirements associated with the compressor installation along with other assumptions that may affect the noise and vibration generated by the Station during normal operation. It is anticipated that all of the recommended noise mitigation measures will be implemented by Algonquin, noting that Algonquin has successfully utilized these type of noise mitigation measures for similar situations/facilities and have proven to be very effective.

8.1 Building Enclosing the Turbine and Compressor

We understand that noise control measures will be applied to the building enclosing the turbine and compressor rather than to the equipment themselves. The following describes specific requirements and other items related to the building components.

- As a minimum, walls/roof should be constructed with an exterior skin of 22–gauge metal. In addition, building interior surfaces should be covered with a minimum of 6–inch thick "high-density" mineral wool (i.e., 6.0-8.0 pcf uniform density) covered with a perforated liner.

- No windows or louvers should be installed in the building walls. Personnel entry doors should be a **STC-36 sound rating**, even if glazing is employed, and should be self-closing and should seal well when closed. The large access door system ("roll-up door") should be consist of an insulated-type door (e.g., designed with 18-ga. exterior facing, 24-ga. backskin with insulation core), and should be installed on the West Side or North Side of the building;

- Building Ventilation: It is anticipated that the building air ventilation system will be designed with air supply fans mounted in the building walls along with roof-mounted air exhaust vents. Assuming this type of air ventilation system, the sound level for each wall air-supply fan should not exceed **50 dBA** at 50 feet, which will require that each supply fan employ an exterior dissipative-type silencer (e.g., 3-ft. length) and an acoustically-lined weatherhood.

8.2 Turbine Exhaust System

The turbine exhaust system for the Station compressor unit should include a silencer system that provides the following dynamic sound insertion loss ("DIL") values, which should minimize any perceptible increase in vibration.

DIL Values for the Exhaust Muffler System in dB per Octave-Band (O.B.) Center Freq. (Hz)

31.5	63	125	250	500	1000	2000	4000	8000
5	18	25	35	45	45	45	35	25

To meet the DIL values and minimize turbine exhaust noise, it is recommended two (2) exhaust silencers (i.e., 2-stage silencer system) be employed. For example, one (1) silencer section should be employed horizontally in the exhaust ducting located inside the Compressor Building ("1st stage horizontal silencer") and the other silencer section could be integrated into the vertical outdoor exhaust stack ("2nd stage vertical silencer"). If a CO converter is employed, which is anticipated, it is assumed that a CO converter system would be inserted upstream of the 1st stage silencer, inside the Compressor Building.

8.3 Aboveground Gas Piping and associated Components

The acoustical analysis indicates that noise control measures, such as acoustical pipe insulation, will be required for outdoor gas piping, noting that most gas piping will be located above ground. The following items for the gas piping and associated components should be addressed:

- Acoustical insulation should be employed for the aboveground suction and discharge piping for the new compressor unit and for aboveground piping associated with the new gas aftercooler. Acoustical pipe insulation should consist of 3-inch thick mineral wool or equivalent type of material (e.g., 6.0 to 8.0 pcf density) that is covered with a mass-filled vinyl jacket (e.g., composite of 1.0 psf mass-filled vinyl laminated to 0.020-inch thick aluminum);

- All outdoor exposed pipe support guides for the outdoor aboveground piping should be covered with an acoustical material and/or acoustical cover. Aboveground valves located outdoors should be covered with an acoustical type of acoustical blanket material.

- Aboveground inlet pipe risers/header for the gas cooler should be covered with acoustical pipe insulation but the outlet pipe risers should not have to be covered with acoustical insulation. It is also recommended that the suction pipe strainer for the new compressor unit be removed soon after the unit is placed in service, if feasible.

8.4 Lube Oil Cooler

The LO cooler should not exceed **58 dBA** at **50 feet** from the cooler perimeter at the full rated operating conditions (i.e., equivalent to a PWL of **92–93 dBA**), and a "special" or "custom" Solar LO cooler will be required to meet the recommended sound requirement.

8.5 Turbine Air Intake System

The turbine air intake system should be designed with at least one (1) in-duct silencer (e.g., min. 5-ft. length), and the silencer should be installed in the ductwork located inside the Compressor Building. The air intake silencer should be capable of providing the following DIL values.

DIL Values in dB per O.B. Center Frequency for the Turbine Air Intake System

31.5 Hz	63 Hz	125 Hz	250 Hz	500 Hz	1000 Hz	2000 Hz	4000 Hz	8000 Hz
2	5	12	15	30	45	50	60	60

8.6 Gas Aftercooler

The sound level generated by the new multi-fan gas aftercooler should not exceed **62 dBA** at **50 feet** at the full rated operating conditions (i.e., all fans operating at maximum design speed), and the gas cooler will need to be designed with "low-noise" fans that operate at low fan tip speeds.

8.7 Station Unit Blowdown Silencer

The unit blowdown silencer should attenuate the unsilenced blowdown noise to a noise level equal to or less than **55 dBA** at 300 feet from the outlet of the silencer, which includes the noise radiated from the shell of the silencer during the blowdown event.

9.0 SUMMARY AND FINAL COMMENT

The following **Table G** summarizes the ambient noise environment around the Station (i.e., ambient L_{dn}), estimated sound contribution of the Station during operation at the receptors/NSAs and "total" cumulative sound level at the NSAs (i.e., Station sound level plus the ambient sound level). The results in **Table G** are defined as the "Noise Quality Analysis" for the Station.

Identified Receptor/NSA and Type of Receptor/NSA	Distance & Direction of Receptor/NSA	Ambient Ldn (dBA)	Est'd Sound Level (Ldn) of Station at Full Load (dBA)	Est'd Station Sound Level (Ldn) + Ambient Ldn (dBA)	Increase above Ambient Ldn (dB)
NSA #1 (Residences)	610 feet (SSE)	70.4	49.0	70.4	0.0
NSA #2 (Residences)	1,370 feet (north)	54.9	42.1	55.1	0.2
NSA #3 (Residences)	1,560 feet (east)	54.0	40.8	54.2	0.2
NSA #4 (Residences)	900 feet (south)	56.5	45.3	56.8	0.3
NSA #5 (Residences)	1,030 feet (SE)	64.3	43.9	64.3	0.0
NSA #6 (Residences)	2,300 feet (SE)	50.6	35.7	50.7	0.1
NSA #7 (Residences)	1,970 feet (ENE)	49.1	38.2	49.4	0.3
NSA #8 (Residences)	2,400 feet (west)	52.6	35.3	52.7	0.1
NSA #9 (School)	4,200 feet (ESE)	49.8	29.1	49.8	0.0

Table G: Noise Quality Analysis for the Weymouth Compressor Station associated with the AB Project

The acoustical analysis presented in this report indicates that the noise attributable to the Weymouth Compressor Station is estimated to be lower than **55 dBA** (L_{dn}) at all surrounding receptors/NSAs. Consequently, the noise generated by the Station should meet the anticipated FERC sound level requirement for the Station. In addition, the results of the acoustical analysis indicate that the Station sound contribution should also meet the MassDEP noise requirements, including the MassDEP noise guideline for pure tone noise condition, and the noise generated by the Station should have minimum noise impact at the surrounding receptors/NSAs, even during nighttime Station operation.

The acoustical analysis also shows that the noise of construction activities and the noise resulting from a unit blowdown event at the Station should have minimum noise impact on the surrounding environment. In addition, since the Station noise sources that could cause perceptible vibration (e.g., turbine exhaust noise) will be adequately mitigated, there should not be any perceptible increase in vibration (direct, or noise-induced) at any NSA during Station operation.

APPENDIX

- **FIGURE 1: AREA LAYOUT SHOWING NSAs WITHIN APPROXIMATELY ½ MILE, LOCATION OF THE CHOSEN SOUND MEASUREMENT POSITIONS AT THE SURROUNDING RECEPTORS AND NSAs FOR THE MOST RECENT AMBIENT SOUND SURVEY**
- **FIGURE 2: CONCEPTUAL LOCATION OF STATION EQUIPMENT/BUILDINGS/PIPING AND STATION FENCELINE**
- **SUMMARY OF THE MEASURED AMBIENT SOUND DATA**
- **ACOUSTICAL ANALYSES (COMPRESSOR STATION)**
- **ANALYSIS METHODOLOGY (NOISE ATTRIBUTABLE TO THE STATION AND A BLOWDOWN EVENT) AND THE SOURCE OF SOUND DATA**
- **ACOUSTICAL ANALYSIS (CONSTRUCTION ACTIVITIES)**
- **DESCRIPTION OF THE ANALYSES METHODOLOGY (CONSTRUCTION ACTIVITIES) AND THE SOURCE OF SOUND DATA**

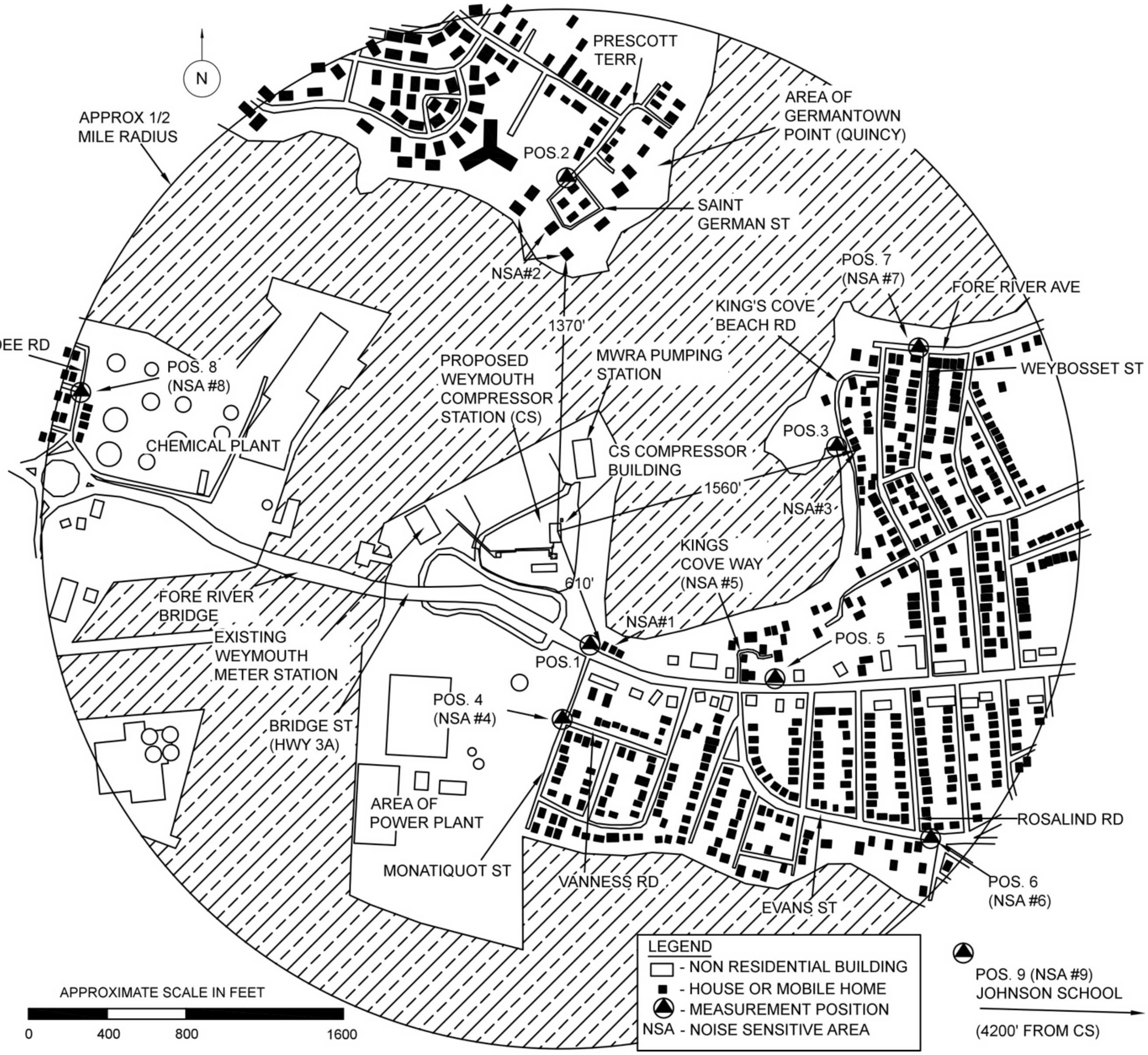


Figure 1: Weymouth Compressor Station: Area Layout showing Receptors/NSAs within ½ Mile Radius, Closest Identified NSAs, Conceptual Layout of the Station and Location of the Chosen Sound Measurements Positions near the Identified Receptors/NSAs.

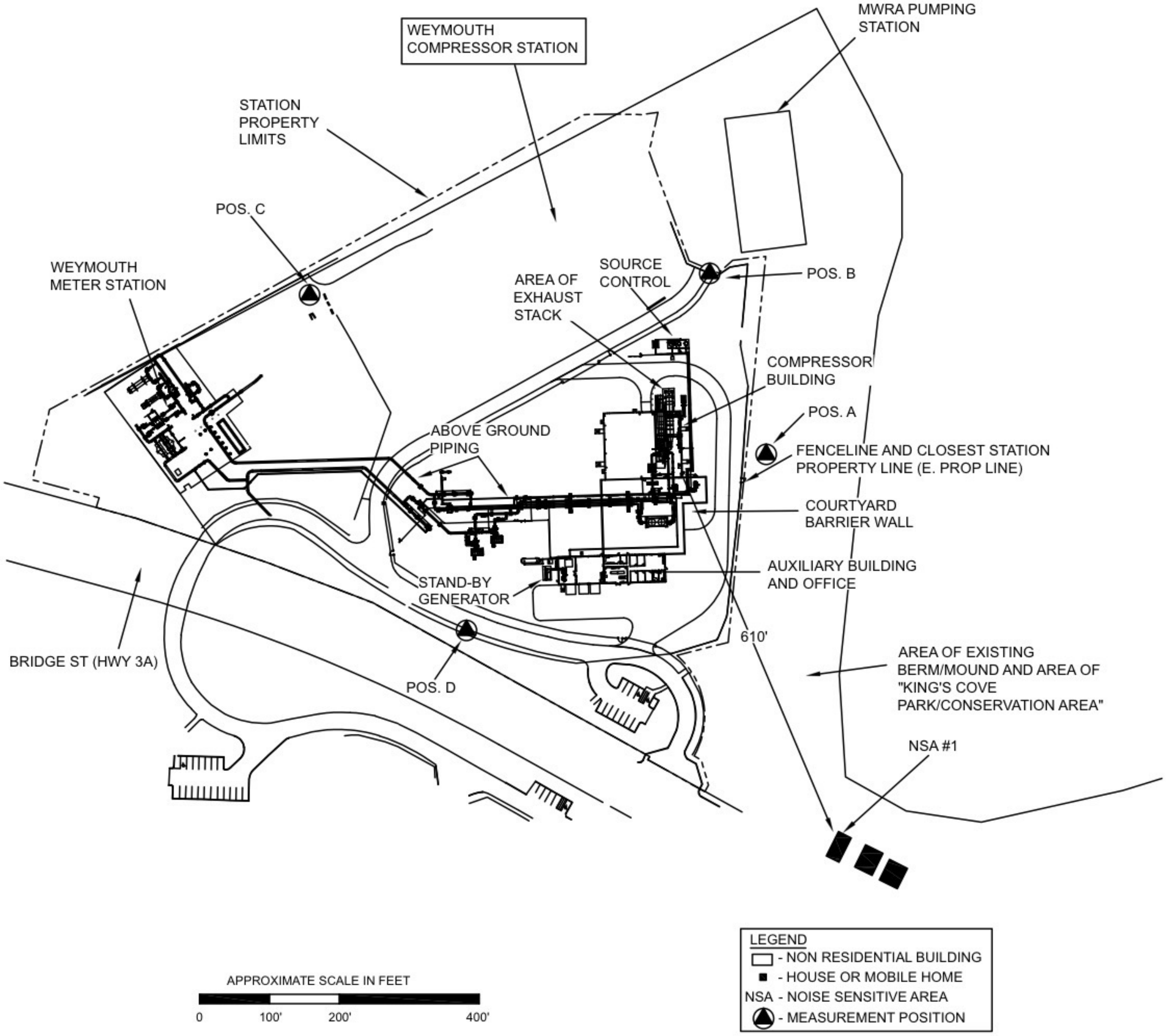


Figure 2: Weymouth Compressor Station: Drawing showing the Conceptual Layout of Station Equipment, Buildings. Aboveground Piping and Area of Courtyard Barrier/Walls.

Measurement Set		Meas'd/Calc'd A-Wt. Levels (dBA)					Avg. of Daytime L90	Avg. of N-time L90 Note (2)	
Meas. Pos. & NSA	Date of Test	Day-time Leq(Ld)	Avg'd of Ld	Night-time Leq(Ln)	Avg'd of Ln	Calc'd Ldn Note (1)			Notes/Observations
Pos. 1 (NSA #1)	(8/14/15)	71.9		47.2					Primary noise during day: traffic along
Closest NSA (residences	(8/14/15)	72.8	**72.4**	46.6	**46.7**	**70.4**	66.4	44.8	Bridge Street, as would be expected
on N. Side of Bridge St.),	(8/14/15)	72.4		46.3					Primary noise during night: industrial,
610 ft. SSE of CS Site									insects, power plant, distant traffic
Pos. 2 (NSA #2)	(8/14/15)	51.5		48.1					Primary noise during day: insects,
Residences in area	(8/14/15)	50.4	**50.3**	48.1	**48.1**	**54.9**	46.8	46.8	industrial, and at times, sound of birds
of Germantown Point,	(8/14/15)	49.0		48.1					Primary noise during night: industrial &
1,370 ft. north of CS Site									insects (no work at Fore River Bridge)
Pos. 3 (NSA #3)	(8/14/15)	50.7		46.0					Primary noise during day: traffic along
Residences along	(8/14/15)	50.0	**50.1**	46.2	**46.9**	**54.0**	48.4	44.0	Bridge St., industrial, sound of waves
Kings Cove Beach Rd.,	(8/14/15)	49.5		48.7					Primary noise during night: industrial &
1,560 ft. east of CS Site									traffic (no work at Fore River Bridge)
Pos. 4 (NSA #4)	(8/14/15)	51.4		50.0					Primary noise during day: power plant
Residences at Vanness	(8/14/15)	50.4	**51.0**	49.9	**49.9**	**56.5**	49.3	48.5	& traffic on Bridge Street
Road & Monatiquot St.,	(8/14/15)	51.2		49.9					Primary noise during night: power plant
900 ft. south of CS Site									& insects (no work at Fore River Bridge)
Pos. 5 (NSA #5)	(8/14/15)	64.5		42.4					Primary noise during day: traffic along
Residences along	(8/14/15)	70.6	**66.2**	42.2	**42.6**	**64.3**	55.1	41.3	Bridge Street, as would be expected
Kings Cove Way,	(8/14/15)	63.4		43.1					Primary noise during night: industrial,
1,030 ft. SE of CS Site									power plant & insects
Pos. 6 (NSA #6)	(8/14/15)	47.3		44.0					Primary noise during day: industrial,
Residences at Evans	(8/14/15)	44.4	**45.1**	43.6	**44.0**	**50.6**	42.6	41.4	traffic along Bridge St. & insects
Street & Rosalind Road,	(8/14/15)	43.6		44.4					Primary noise during night: distant
2,300 ft. SE of CS Site									traffic, industrial & some insects.
Pos. 7 (NSA #7)	(8/14/15)	45.2		41.1					Primary noise during day: industrial,
Residences at Fore River	(8/14/15)	47.9	**46.9**	40.5	**41.3**	**49.1**	44.5	39.3	distant small boats & some insects
Ave. & Weybosset St.,	(8/14/15)	47.6		42.2					Primary noise during night: industrial &
1,970 ft. ENE of CS Site									some sound of insects
Pos. 8 (NSA #8)	(8/14/15)	49.5		45.9					Primary noise during day: industrial,
Residences along	(8/14/15)	48.0	**48.2**	45.9	**45.7**	**52.6**	46.1	44.5	traffic along Bridge St. & some insects
Dee Road, 2,400 ft.	(8/14/15)	47.1		45.4					Primary noise during night: industrial,
west of CS Site									distant traffic & some insects
Pos. 9 (NSA #9)	(8/14/15)	47.2		42.7					Primary noise during day: distant traffic
Johnson School,	(8/14/15)	47.6	**47.0**	42.2	**42.4**	**49.8**	43.3	41.0	and at times, sound of wind in trees.
approx. 4,200 ft. ESE	(8/14/15)	46.3		42.2					Primary noise during night: distant
of the CS Site									traffic and at times, sound of insects

Table 1: **Site of Weymouth Compressor Station ("CS Site"): Summary of Measured Ambient Daytime Sound Levels (Ld), Daytime L90, Ambient Nighttime Sound Levels (Ln) and Nighttime L90 at the Receptors/NSAs as Measured on August 14, 2014 along with Resulting Ambient Ldn.**

Note (1): Ldn calculated by adding 6.4 dB to the measured Ld. If both the Ld and Ln are measured and/or estimated, the Ldn is calculated using the following formula:

$$L_{\mathrm{dn}} = 10\log_{10}\left(\frac{15}{24}10^{L_{\mathrm{d}}/10} + \frac{9}{24}10^{(L_{\mathrm{n}}+10)/10}\right)$$

Note (2): Nightime L90 levels were measured between 12:00 AM & 3:00 AM and represents lowest ambient A-wt. sound level

Measurement Set		Temp.	R.H.	Wind	Wind	Peak	
Meas. Positions/Period	Time Frame/Date of Tests	(°F)	(%)	Direction	Speed	Wind	Sky Conditions
Pos. 1 to 9 (Daytime)	10:00 AM to 12:30 PM (8/14/15)	78	47	From the south	1-3 mph	3 mph	Clear Skies
Pos. 1 to 9 (Nighttime)	12:00 AM to 3:00 AM (8/14/15)	71	61	From the east	0-1 mph	2 mph	Clear Skies

Table 2: **Site of Weymouth Compressor Station: Summary of the Meteorological Conditions during the Sound Survey on August 14, 2015.**

Measurement Set		Meas'd/Calc'd A-Wt. Levels (dBA)					Avg. of Daytime L90	Avg. of N-time L90 Note (2)	Notes/Observations
Meas. Pos. & NSA	Date of Test	Day-time Leq(Ld)	Avg'd of Ld	Night-time Leq(Ln)	Avg'd of Ln	Calc'd Ldn Note (1)			
Pos. D South property line of the CS Site	(9/8/16 & 9/9/16) (9/8/16 & 9/9/16) (9/8/16 & 9/9/16)	52.8 52.5 55.2	**53.5**	50.5 48.8 49.3	**49.5**	**56.8**	50.6	46.9	Primary noise during day: construction, traffic, insects Primary noise during night: refinery, traffic, insects
Pos. A East property line of the CS Site	(9/8/16 & 9/9/16) (9/8/16 & 9/9/16) (9/8/16 & 9/9/16)	49.4 48.7 51.7	**50.0**	51.1 50.7 53.3	**51.7**	**57.9**	47.8	49.5	Primary noise during day: refinery, construction, traffic, insects Primary noise during night: refinery, traffic, insects
Pos. C West property line of the CS Site	(9/8/16 & 9/9/16) (9/8/16 & 9/9/16) (9/8/16 & 9/9/16)	57.1 57.1 56.6	**56.9**	51.7 51.0 52.3	**51.7**	**59.4**	54.9	50.2	Primary noise during day: refinery, construction, traffic, insects Primary noise during night: refinery, traffic, insects
Pos. B North property line of the CS Site	(9/8/16 & 9/9/16) (9/8/16 & 9/9/16) (9/8/16 & 9/9/16)	51.9 52.0 51.4	**51.8**	52.4 54.1 54.9	**53.8**	**60.0**	50.5	51.7	Primary noise during day: refinery, sewage plant, construction, traffic, insects Primary noise during night: refinery, sewage plant, traffic, insects

Table 1A: **Site of Weymouth Compressor Station ("CS Site"): Summary of Measured Ambient Daytime Sound Levels (Ld), Daytime L90, Ambient Nighttime Sound Levels (Ln) and Nighttime L90 at CS Site Property Line, as Measured on Sept. 8 & 9, 2016 along with Resulting Ambient Ldn.**

Note (1): Ldn calculated by adding 6.4 dB to the measured Ld. If both the Ld and Ln are measured and/or estimated, the Ldn is calculated using the following formula:

$$L_{\mathrm{dn}} = 10\log_{10}\left(\frac{15}{24}10^{L_d/10} + \frac{9}{24}10^{(L_n+10)/10}\right)$$

Note (2): Nightime L90 levels were measured between 12:00 AM & 3:00 AM and represents lowest ambient A-wt. sound levels

Measurement Set		Temp. (°F)	R.H. (%)	Wind Direction	Wind Speed	Peak Wind	Sky Conditions
Meas. Positions/Period	Time Frame/Date of Tests						
Pos. A, B, C & D (Daytime)	12:00 PM to 2:00 PM (9/8/16)	72	90	From the east	1-4 mph	5 mph	Cloudy
Pos. A, B, C & D (N-time)	12:00 AM to 2:00 AM (9/9/16)	65-70	85	From the north	1-3 mph	5 mph	Cloudy

Table 2A: **Site of Weymouth Compressor Station: Summary of the Meteorological Conditions during Sound Tests on Sept. 8 & 9, 2016 at CS Site Property Line.**

Measurement Set		Unweighted Sound Pressure Level (SPL) in dB per O.B. Freq. (in Hz)									A-Wt.
Meas. Pos. & NSA	**Time/Date of Test**	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**Level**
Pos. 1 (NSA #1)	12:25 PM (8/14/15)	70.0	68.2	64.8	63.1	66.0	69.6	64.5	55.9	47.0	71.9
Closest NSA (residences	12:26 PM (8/14/15)	73.3	73.2	70.5	67.2	68.0	70.2	64.9	56.5	48.5	72.8
on N. Side of Bridge St.),	12:27 PM (8/14/15)	69.1	72.0	69.0	67.4	65.7	70.1	64.7	55.5	47.1	72.4
610 ft. SSE of CS Site	**Avg. A-Wt. & SPL**	**70.8**	**71.1**	**68.1**	**65.9**	**66.6**	**70.0**	**64.7**	**56.0**	**47.5**	**72.4**
Pos. 2 (NSA #2)	10:57 AM (8/14/15)	71.2	61.2	56.2	49.0	42.9	41.9	39.2	44.8	47.4	51.5
Residences in area	10:58 AM (8/14/15)	71.5	61.1	56.5	51.8	46.4	41.7	36.9	39.7	43.9	50.4
of Germantown Point,	11:00 AM (8/14/15)	72.1	61.3	56.1	49.7	44.6	42.4	37.4	37.5	38.3	49.0
1,370 ft. north of CS Site	**Avg. A-Wt. & SPL**	**71.6**	**61.2**	**56.3**	**50.2**	**44.6**	**42.0**	**37.8**	**40.7**	**43.2**	**50.3**
Pos. 3 (NSA #3)	12:01 PM (8/14/15)	63.0	63.5	60.9	49.9	44.8	45.9	39.0	33.7	27.5	50.7
Residences along	12:02 PM (8/14/15)	62.6	64.3	61.5	50.0	43.3	43.6	38.2	33.1	28.2	50.0
Kings Cove Beach Rd.,	12:03 PM (8/14/15)	63.2	62.8	58.8	48.7	44.0	44.4	39.1	35.3	30.1	49.5
1,560 ft. east of CS Site	**Avg. A-Wt. & SPL**	**62.9**	**63.5**	**60.4**	**49.5**	**44.0**	**44.6**	**38.8**	**34.0**	**28.6**	**50.1**
Pos. 4 (NSA #4)	12:16 PM (8/14/15)	64.7	64.2	60.4	51.0	46.0	46.6	41.9	33.4	28.1	51.4
Residences at Vanness	12:17 PM (8/14/15)	64.7	63.8	57.5	49.9	44.8	46.1	41.5	33.2	27.1	50.4
Road & Monatiquot St.,	12:18 PM (8/14/15)	64.7	63.9	57.9	51.8	46.5	46.6	41.6	33.6	25.5	51.2
900 ft. south of CS Site	**Avg. A-Wt. & SPL**	**64.7**	**64.0**	**58.6**	**50.9**	**45.8**	**46.4**	**41.7**	**33.4**	**26.9**	**51.0**
Pos. 5 (NSA #5)	12:08 PM (8/14/15)	65.3	64.3	58.8	57.2	58.7	62.6	55.7	46.6	39.7	64.5
Residences along	12:11 PM (8/14/15)	64.8	72.7	66.1	64.1	66.0	68.3	62.2	53.3	44.4	70.6
Kings Cove Way,	12:12 PM (8/14/15)	62.9	60.8	57.9	57.2	58.8	61.4	53.9	44.9	36.2	63.4
1,030 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**64.3**	**65.9**	**60.9**	**59.5**	**61.2**	**64.1**	**57.3**	**48.3**	**40.1**	**66.2**
Pos. 6 (NSA #6)	11:26 AM (8/14/15)	54.0	56.0	53.2	46.6	41.5	42.7	39.1	36.3	29.6	47.3
Residences at Evans	11:30 AM (8/14/15)	54.1	55.3	52.3	44.9	39.6	38.8	34.9	31.9	27.1	44.4
Street & Rosalind Road,	11:37 AM (8/14/15)	52.2	54.8	50.9	43.2	38.5	38.2	34.9	32.4	24.5	43.6
2,300 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**53.4**	**55.4**	**52.1**	**44.9**	**39.9**	**39.9**	**36.3**	**33.5**	**27.1**	**45.1**
Pos. 7 (NSA #7)	11:54 AM (8/14/15)	56.6	58.0	55.7	47.6	41.1	36.3	32.2	28.6	32.4	45.2
Residences at Fore River	11:55 AM (8/14/15)	57.8	61.9	59.4	50.6	43.0	39.2	32.7	27.7	24.1	47.9
Ave. & Weybosset St.,	11:57 AM (8/14/15)	58.5	60.4	60.8	49.2	39.6	37.8	33.5	27.4	20.7	47.6
1,970 ft. ENE of CS Site	**Avg. A-Wt. & SPL**	**57.6**	**60.1**	**58.6**	**49.1**	**41.2**	**37.8**	**32.8**	**27.9**	**25.7**	**46.9**
Pos. 8 (NSA #8)	11:15 AM (8/14/15)	60.2	59.3	54.4	48.2	45.1	43.4	40.9	40.9	34.1	49.5
Residences along	11:17 AM (8/14/15)	60.6	58.9	53.3	46.0	42.3	42.0	39.4	40.2	33.1	48.0
Dee Road, 2,400 ft.	11:18 AM (8/14/15)	59.3	59.4	53.2	46.2	40.7	41.1	38.2	39.1	32.1	47.1
west of CS Site	**Avg. A-Wt. & SPL**	**60.0**	**59.2**	**53.6**	**46.8**	**42.7**	**42.2**	**39.5**	**40.1**	**33.1**	**48.2**
Pos. 9 (NSA #9)	11:44 AM (8/14/15)	56.2	53.6	52.8	46.0	41.6	41.3	38.6	38.8	35.4	47.2
Johnson School,	11:47 AM (8/14/15)	54.5	53.7	53.0	45.9	42.7	43.5	39.0	35.1	30.1	47.6
approx. 4,200 ft. ESE	11:48 AM (8/14/15)	50.9	52.8	54.0	48.9	40.2	41.0	37.0	31.2	25.7	46.3
of the CS Site	**Avg. A-Wt. & SPL**	**53.9**	**53.4**	**53.3**	**46.9**	**41.5**	**41.9**	**38.2**	**35.0**	**30.4**	**47.0**

Table 3: **Weymouth Compressor Station: Measured Ambient Daytime Leq (Ld) and associated Ambient Unweighted Octave-Band (O.B.) SPLs at Receptors/NSAs, as Meas'd on 8/14/15.**

Measurement Set		Unweighted Sound Pressure Level (SPL) in dB per O.B. Freq. (in Hz)									A-Wt.
Meas. Pos. & NSA	**Time/Date of Test**	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**Level**
Pos. 1 (NSA #1)	2:01 AM (8/14/15)	62.0	58.8	53.1	44.8	41.8	39.6	42.5	31.7	23.6	47.2
Closest NSA (residences	2:04 AM (8/14/15)	60.2	58.3	52.3	44.7	41.1	38.4	42.2	31.3	20.2	46.6
on N. Side of Bridge St.),	2:14 AM (8/14/15)	60.3	58.9	53.4	45.1	40.7	38.2	41.0	32.3	20.6	46.3
610 ft. SSE of CS Site	**Avg. A-Wt. & SPL**	**60.8**	**58.7**	**52.9**	**44.9**	**41.2**	**38.7**	**41.9**	**31.8**	**21.5**	**46.7**
Pos. 2 (NSA #2)	12:21 AM (8/14/15)	63.7	59.1	55.8	49.3	42.9	42.1	40.2	32.8	25.2	48.1
Residences in area	12:22 AM (8/14/15)	62.8	59.3	56.0	49.4	43.2	41.6	40.2	32.9	25.2	48.1
of Germantown Point,	12:24 AM (8/14/15)	62.8	58.8	55.8	49.2	43.1	41.8	40.5	33.6	25.4	48.1
1,370 ft. north of CS Site	**Avg. A-Wt. & SPL**	**63.1**	**59.1**	**55.9**	**49.3**	**43.1**	**41.8**	**40.3**	**33.1**	**25.3**	**48.1**
Pos. 3 (NSA #3)	1:34 AM (8/14/15)	58.6	57.7	53.8	43.1	39.5	39.6	40.3	32.3	20.6	46.0
Residences along	1:36 AM (8/14/15)	58.1	57.1	53.7	43.4	39.7	39.7	40.7	32.6	21.7	46.2
Kings Cove Beach Rd.,	1:37 AM (8/14/15)	57.6	56.8	52.9	44.1	40.6	45.4	42.2	34.3	21.4	48.7
1,560 ft. east of CS Site	**Avg. A-Wt. & SPL**	**58.1**	**57.2**	**53.5**	**43.5**	**39.9**	**41.6**	**41.1**	**33.1**	**21.2**	**46.9**
Pos. 4 (NSA #4)	1:55 AM (8/14/15)	63.3	60.7	54.4	48.1	44.4	43.7	44.6	38.2	28.4	50.0
Residences at Vanness	1:56 AM (8/14/15)	63.1	60.9	55.0	48.1	44.8	43.9	43.7	37.7	29.1	49.9
Road & Monatiquot St.,	1:57 AM (8/14/15)	63.8	61.0	54.8	48.0	45.0	43.7	44.2	36.5	28.0	49.9
900 ft. south of CS Site	**Avg. A-Wt. & SPL**	**63.4**	**60.9**	**54.7**	**48.1**	**44.7**	**43.8**	**44.2**	**37.5**	**28.5**	**49.9**
Pos. 5 (NSA #5)	1:48 AM (8/14/15)	52.1	53.2	49.3	43.9	37.3	37.1	33.5	27.3	23.8	42.4
Residences along	1:50 AM (8/14/15)	52.2	53.6	49.9	44.5	37.8	35.4	33.0	27.5	23.8	42.2
Kings Cove Way,	1:51 AM (8/14/15)	52.8	53.6	50.9	45.1	38.5	37.1	33.9	27.9	24.7	43.1
1,030 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**52.4**	**53.5**	**50.0**	**44.5**	**37.9**	**36.5**	**33.5**	**27.6**	**24.1**	**42.6**
Pos. 6 (NSA #6)	1:06 AM (8/14/15)	52.9	54.2	48.9	42.5	38.3	38.1	32.5	38.0	25.0	44.0
Residences at Evans	1:08 AM (8/14/15)	51.7	52.6	48.0	42.6	36.8	37.2	31.7	38.5	25.5	43.6
Street & Rosalind Road,	1:10 AM (8/14/15)	51.1	52.9	48.7	43.0	37.7	38.9	32.2	38.8	26.5	44.4
2,300 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**51.9**	**53.2**	**48.5**	**42.7**	**37.6**	**38.1**	**32.1**	**38.4**	**25.7**	**44.0**
Pos. 7 (NSA #7)	1:25 AM (8/14/15)	56.7	52.8	47.5	41.9	37.7	36.2	30.9	25.0	18.9	41.1
Residences at Fore River	1:27 AM (8/14/15)	56.1	53.2	47.6	40.4	36.5	35.8	30.2	24.6	18.3	40.5
Ave. & Weybosset St.,	1:28 AM (8/14/15)	56.2	52.7	46.6	42.1	38.2	38.5	31.7	25.1	19.3	42.2
1,970 ft. ENE of CS Site	**Avg. A-Wt. & SPL**	**56.3**	**52.9**	**47.2**	**41.5**	**37.5**	**36.8**	**30.9**	**24.9**	**18.8**	**41.3**
Pos. 8 (NSA #8)	12:44 AM (8/14/15)	57.1	54.0	49.0	42.3	37.4	37.6	36.1	41.6	33.7	45.9
Residences along	12:45 AM (8/14/15)	57.0	53.6	47.7	41.2	37.1	37.8	36.5	41.7	33.9	45.9
Dee Road, 2,400 ft.	12:47 AM (8/14/15)	57.0	53.3	47.2	40.3	36.6	36.9	35.4	41.6	33.8	45.4
west of CS Site	**Avg. A-Wt. & SPL**	**57.0**	**53.6**	**48.0**	**41.3**	**37.0**	**37.4**	**36.0**	**41.6**	**33.8**	**45.7**
Pos. 9 (NSA #9)	1:15 AM (8/14/15)	51.2	55.2	49.0	41.7	37.0	36.7	35.5	32.5	24.3	42.7
Johnson School,	1:16 AM (8/14/15)	50.4	54.6	49.2	41.0	36.8	36.1	34.0	32.8	24.8	42.2
approx. 4,200 ft. ESE	1:18 AM (8/14/15)	51.1	54.5	50.1	41.4	37.2	34.9	34.2	32.8	23.8	42.2
of the CS Site	**Avg. A-Wt. & SPL**	**50.9**	**54.8**	**49.4**	**41.4**	**37.0**	**35.9**	**34.6**	**32.7**	**24.3**	**42.4**

Table 4: **Weymouth Compressor Station: Measured Ambient Nighttime Leq (Ln) and associated Ambient Unweighted Octave-Band (O.B.) SPLs at Receptors/NSAs, as Meas'd on 8/14/15.**

Measurement Set		Unweighted Sound Pressure Level (SPL) in dB per O.B. Freq. (in Hz)									A-Wt.
Meas. Pos. & NSA	Time/Date of Test	31.5	63	125	250	500	1000	2000	4000	8000	Level
Pos. 1 (NSA #1)	12:25 PM (8/14/15)	66.1	64.9	61.0	58.8	60.5	65.3	60.1	51.0	40.9	67.4
Closest NSA (residences	12:26 PM (8/14/15)	68.5	67.8	62.7	60.9	58.7	63.9	57.9	47.8	37.8	65.9
on N. Side of Bridge St.),	12:27 PM (8/14/15)	66.1	65.3	61.2	58.9	58.2	63.9	58.0	47.2	35.7	65.8
610 ft. SSE of CS Site	**Avg. A-Wt. & SPL**	**66.9**	**66.0**	**61.6**	**59.5**	**59.1**	**64.4**	**58.7**	**48.7**	**38.1**	**66.4**
Pos. 2 (NSA #2)	10:57 AM (8/14/15)	68.4	59.5	54.7	47.3	41.5	40.5	36.8	37.1	31.3	46.9
Residences in area	10:58 AM (8/14/15)	68.7	59.1	54.7	47.0	42.0	40.1	35.6	35.8	30.7	46.5
of Germantown Point,	11:00 AM (8/14/15)	69.9	59.3	54.5	47.9	42.7	40.5	36.4	35.1	32.4	47.0
1,370 ft. north of CS Site	**Avg. A-Wt. & SPL**	**69.0**	**59.3**	**54.6**	**47.4**	**42.1**	**40.4**	**36.3**	**36.0**	**31.5**	**46.8**
Pos. 3 (NSA #3)	12:01 PM (8/14/15)	60.3	61.4	57.6	48.2	43.8	44.4	37.9	31.9	24.7	48.8
Residences along	12:02 PM (8/14/15)	59.5	61.8	59.2	48.1	42.2	42.5	37.2	31.6	24.5	48.3
Kings Cove Beach Rd.,	12:03 PM (8/14/15)	58.6	60.3	56.9	47.2	43.0	43.0	37.9	33.2	27.3	48.0
1,560 ft. east of CS Site	**Avg. A-Wt. & SPL**	**59.5**	**61.2**	**57.9**	**47.8**	**43.0**	**43.3**	**37.7**	**32.2**	**25.5**	**48.4**
Pos. 4 (NSA #4)	12:16 PM (8/14/15)	62.0	62.1	57.8	49.4	44.3	44.4	39.8	31.7	25.8	49.3
Residences at Vanness	12:17 PM (8/14/15)	61.9	61.8	56.0	48.5	43.6	44.8	40.3	31.0	25.1	49.0
Road & Monatiquot St.,	12:18 PM (8/14/15)	62.2	62.1	56.3	49.5	44.4	45.4	40.6	32.3	22.8	49.6
900 ft. south of CS Site	**Avg. A-Wt. & SPL**	**62.0**	**62.0**	**56.7**	**49.1**	**44.1**	**44.9**	**40.2**	**31.7**	**24.6**	**49.3**
Pos. 5 (NSA #5)	12:08 PM (8/14/15)	59.7	57.2	53.1	49.1	46.6	48.0	42.0	34.1	26.3	51.0
Residences along	12:11 PM (8/14/15)	60.5	59.6	57.8	56.9	54.5	58.4	53.1	45.5	36.4	60.9
Kings Cove Way,	12:12 PM (8/14/15)	59.7	57.4	54.0	51.2	48.4	51.1	43.5	35.2	28.1	53.4
1,030 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**60.0**	**58.1**	**55.0**	**52.4**	**49.8**	**52.5**	**46.2**	**38.3**	**30.3**	**55.1**
Pos. 6 (NSA #6)	11:26 AM (8/14/15)	51.5	53.9	50.7	43.3	39.7	40.5	35.8	30.5	24.3	44.6
Residences at Evans	11:30 AM (8/14/15)	50.3	52.8	49.9	42.8	37.8	36.5	31.8	30.2	25.4	42.1
Street & Rosalind Road,	11:37 AM (8/14/15)	49.4	52.9	49.3	41.8	36.6	35.5	30.6	26.5	21.6	41.0
2,300 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**50.4**	**53.2**	**50.0**	**42.6**	**38.0**	**37.5**	**32.7**	**29.1**	**23.8**	**42.6**
Pos. 7 (NSA #7)	11:54 AM (8/14/15)	54.3	55.5	52.7	43.1	37.8	34.7	30.0	24.8	17.3	42.0
Residences at Fore River	11:55 AM (8/14/15)	55.5	58.2	57.3	49.2	40.4	37.6	30.8	24.9	17.5	45.9
Ave. & Weybosset St.,	11:57 AM (8/14/15)	56.4	58.8	58.2	47.7	38.6	36.6	31.7	25.9	18.9	45.6
1,970 ft. ENE of CS Site	**Avg. A-Wt. & SPL**	**55.4**	**57.5**	**56.1**	**46.7**	**38.9**	**36.3**	**30.8**	**25.2**	**17.9**	**44.5**
Pos. 8 (NSA #8)	11:15 AM (8/14/15)	57.3	56.9	52.0	44.5	41.4	41.3	37.8	39.1	32.6	46.9
Residences along	11:17 AM (8/14/15)	57.0	56.9	51.4	44.0	40.8	40.6	37.7	39.1	31.7	46.5
Dee Road, 2,400 ft.	11:18 AM (8/14/15)	56.7	57.0	50.9	43.3	39.0	38.5	35.5	38.1	30.5	45.0
west of CS Site	**Avg. A-Wt. & SPL**	**57.0**	**56.9**	**51.4**	**43.9**	**40.4**	**40.1**	**37.0**	**38.8**	**31.6**	**46.1**
Pos. 9 (NSA #9)	11:44 AM (8/14/15)	50.5	50.4	49.7	42.7	38.4	38.0	35.8	33.7	29.1	43.6
Johnson School,	11:47 AM (8/14/15)	50.0	50.8	50.2	42.9	39.8	40.6	36.8	31.1	22.7	44.7
approx. 4,200 ft. ESE	11:48 AM (8/14/15)	47.4	50.2	48.5	41.8	36.4	36.9	33.6	26.4	18.2	41.6
of the CS Site	**Avg. A-Wt. & SPL**	**49.3**	**50.5**	**49.5**	**42.5**	**38.2**	**38.5**	**35.4**	**30.4**	**23.3**	**43.3**

Table 5: **Weymouth Compressor Station: Measured Ambient Daytime L90 and associated Ambient Unweighted Octave-Band (O.B.) SPLs at Receptors/NSAs, as Meas'd on 8/14/15.**

Measurement Set		Unweighted Sound Pressure Level (SPL) in dB per O.B. Freq. (in Hz)									A-Wt.
Meas. Pos. & NSA	Time/Date of Test	31.5	63	125	250	500	1000	2000	4000	8000	Level
Pos. 1 (NSA #1)	2:01 AM (8/14/15)	58.3	56.6	51.0	42.7	39.9	37.7	40.5	30.4	19.8	45.2
Closest NSA (residences	2:04 AM (8/14/15)	57.2	56.1	50.8	43.3	40.0	37.2	40.3	29.7	19.5	45.0
on N. Side of Bridge St.),	2:14 AM (8/14/15)	57.3	56.5	51.1	43.2	39.1	35.8	39.3	30.1	19.3	44.3
610 ft. SSE of CS Site	**Avg. A-Wt. & SPL**	**57.6**	**56.4**	**51.0**	**43.1**	**39.7**	**36.9**	**40.0**	**30.1**	**19.5**	**44.8**
Pos. 2 (NSA #2)	12:21 AM (8/14/15)	60.0	57.1	54.3	48.1	42.0	40.9	38.9	32.1	24.5	46.9
Residences in area	12:22 AM (8/14/15)	59.2	57.1	54.5	48.1	41.9	40.4	38.9	32.2	24.0	46.8
of Germantown Point,	12:24 AM (8/14/15)	59.2	56.9	54.3	48.1	41.9	40.4	39.3	32.6	24.5	46.8
1,370 ft. north of CS Site	**Avg. A-Wt. & SPL**	**59.5**	**57.0**	**54.4**	**48.1**	**41.9**	**40.6**	**39.0**	**32.3**	**24.3**	**46.8**
Pos. 3 (NSA #3)	1:34 AM (8/14/15)	55.3	55.5	52.0	41.9	38.6	36.3	38.3	30.1	19.6	43.9
Residences along	1:36 AM (8/14/15)	55.0	55.1	51.7	41.8	38.8	36.4	38.2	30.3	19.6	43.9
Kings Cove Beach Rd.,	1:37 AM (8/14/15)	54.5	55.0	51.4	42.0	39.1	36.7	38.6	31.2	20.0	44.1
1,560 ft. east of CS Site	**Avg. A-Wt. & SPL**	**54.9**	**55.2**	**51.7**	**41.9**	**38.8**	**36.5**	**38.4**	**30.5**	**19.7**	**44.0**
Pos. 4 (NSA #4)	1:55 AM (8/14/15)	60.4	58.6	53.0	46.7	43.2	42.5	43.2	36.2	27.1	48.6
Residences at Vanness	1:56 AM (8/14/15)	60.1	59.0	53.5	46.8	42.9	42.5	42.3	35.6	27.1	48.3
Road & Monatiquot St.,	1:57 AM (8/14/15)	60.6	58.9	53.2	46.4	43.4	42.5	42.8	35.1	26.4	48.5
900 ft. south of CS Site	**Avg. A-Wt. & SPL**	**60.4**	**58.8**	**53.2**	**46.6**	**43.2**	**42.5**	**42.8**	**35.6**	**26.9**	**48.5**
Pos. 5 (NSA #5)	1:48 AM (8/14/15)	49.3	51.2	48.0	42.8	36.1	34.6	32.3	26.6	21.3	40.8
Residences along	1:50 AM (8/14/15)	49.5	51.7	48.5	43.5	37.0	34.6	32.3	26.8	21.3	41.2
Kings Cove Way,	1:51 AM (8/14/15)	50.1	51.6	49.4	43.4	37.7	35.8	33.2	27.1	22.5	41.9
1,030 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**49.6**	**51.5**	**48.6**	**43.2**	**36.9**	**35.0**	**32.6**	**26.8**	**21.7**	**41.3**
Pos. 6 (NSA #6)	1:06 AM (8/14/15)	49.9	52.3	47.4	41.0	36.8	36.3	30.5	33.2	21.1	41.5
Residences at Evans	1:08 AM (8/14/15)	49.1	50.6	46.4	40.3	35.2	36.0	30.5	34.1	21.9	41.2
Street & Rosalind Road,	1:10 AM (8/14/15)	48.8	51.0	46.7	41.0	36.2	36.9	30.4	33.2	21.4	41.5
2,300 ft. SE of CS Site	**Avg. A-Wt. & SPL**	**49.3**	**51.3**	**46.8**	**40.8**	**36.1**	**36.4**	**30.5**	**33.5**	**21.5**	**41.4**
Pos. 7 (NSA #7)	1:25 AM (8/14/15)	54.0	50.8	46.0	40.2	36.1	33.8	28.8	22.8	16.7	39.2
Residences at Fore River	1:27 AM (8/14/15)	53.3	51.2	45.2	38.6	34.6	33.4	28.2	22.6	16.5	38.3
Ave. & Weybosset St.,	1:28 AM (8/14/15)	52.8	50.8	45.1	40.8	36.2	36.3	30.0	23.4	16.4	40.2
1,970 ft. ENE of CS Site	**Avg. A-Wt. & SPL**	**53.4**	**50.9**	**45.4**	**39.9**	**35.6**	**34.5**	**29.0**	**22.9**	**16.5**	**39.3**
Pos. 8 (NSA #8)	12:44 AM (8/14/15)	54.6	52.0	47.2	40.0	36.2	36.6	35.2	40.2	32.6	44.5
Residences along	12:45 AM (8/14/15)	54.5	51.6	46.1	39.4	35.7	36.6	35.1	40.6	32.8	44.6
Dee Road, 2,400 ft.	12:47 AM (8/14/15)	54.6	51.3	45.7	38.9	35.5	36.2	34.6	40.5	32.6	44.4
west of CS Site	**Avg. A-Wt. & SPL**	**54.6**	**51.6**	**46.3**	**39.4**	**35.8**	**36.5**	**35.0**	**40.4**	**32.7**	**44.5**
Pos. 9 (NSA #9)	1:15 AM (8/14/15)	47.4	53.4	47.9	40.2	35.5	34.7	33.7	31.3	22.7	41.1
Johnson School,	1:16 AM (8/14/15)	47.7	53.0	48.0	40.0	35.8	34.4	33.4	31.6	23.4	41.1
approx. 4,200 ft. ESE	1:18 AM (8/14/15)	48.3	52.8	48.4	40.3	36.1	33.5	33.2	31.6	22.1	40.9
of the CS Site	**Avg. A-Wt. & SPL**	**47.8**	**53.1**	**48.1**	**40.2**	**35.8**	**34.2**	**33.4**	**31.5**	**22.7**	**41.0**

Table 6: **Weymouth Compressor Station: Measured Ambient Nighttime L90 and associated Ambient Unweighted Octave-Band (O.B.) SPLs at Receptors/NSAs, as Meas'd on 8/14/15.**

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted PWL or SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	Calc'd Ldn (dBA)
1)	PWL of Turbine/Compressor inside Building	110	110	112	112	110	110	112	118	112	121	
	Attenuation of the Building	-8	-12	-18	-26	-32	-35	-38	-40	-40		
	Misc. Atten. (Shielding, Land Contour, Ground Effect)	0	0	0	0	-1	-1	-3	-4	-4		
610	Hemispherical Radiation	-53	-53	-53	-53	-53	-53	-53	-53	-53		
610	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-2	-5	-8		
610	Source Sound Level Contribution	49	45	40	32	23	20	16	16	6	29	
2)	PWL of Unsilenced Turbine Exhaust	120	123	120	123	127	119	112	104	96	126	
	Atten. of Noise Control (Custom 2-Silencer System)	-7	-18	-28	-35	-45	-45	-45	-35	-25		
	Misc. Atten. (Shielding, Land Contour, Ground Effect)	0	0	0	0	0	0	0	0	0		
680	Hemispherical Radiation	-54	-54	-54	-54	-54	-54	-54	-54	-54		
680	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-2	-5	-9		
680	Source Sound Level Contribution	59	51	38	33	27	19	11	9	7	31	
3)	PWL of Aboveground Piping & Components	98	98	102	95	96	105	110	108	100	114	
	Atten. of Noise Control (Insulation & Courtyard Effect)	4	4	0	-4	-10	-15	-18	-20	-20		
	Misc. Atten. (Shielding, Land Contour, Ground Effect)	0	0	0	0	-1	-1	-3	-4	-4		
600	Hemispherical Radiation	-53	-53	-53	-53	-53	-53	-53	-53	-53		
600	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-2	-5	-8		
600	Source Sound Level Contribution	49	49	49	37	31	35	34	26	15	40	
4)	PWL of LO Cooler	105	100	94	90	88	84	80	78	75	90	
	NR of Noise Control	0	0	0	0	0	0	0	0	0		
	Misc. Atten. (Shielding, Land Contour, Ground Effect)	0	0	0	0	-1	-1	-3	-4	-4		
680	Hemispherical Radiation	-54	-54	-54	-54	-54	-54	-54	-54	-54		
680	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-2	0	-1	-2	-5	-9		
680	Source Sound Level Contribution	51	46	40	34	32	28	21	14	7	33	
5)	PWL of Unsilenced Turbine Air Intake	108	114	120	121	122	124	129	152	144	153	
	Attenuation of Intake Silencer System ("Custom")	-2	-5	-12	-15	-30	-45	-50	-60	-60		
	Attenuation of Air Intake Filter	-1	-6	-12	-18	-22	-25	-25	-25	-20		
	Misc. Atten. (Shielding, Land Contour, Ground Effect)	0	0	0	0	-1	-1	-3	-4	-4		
680	Hemispherical Radiation	-54	-54	-54	-54	-54	-54	-54	-54	-54		
680	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-2	-5	-9		
680	Source Sound Level Contribution	51	49	42	33	14	0	0	3	0	29	
6)	PWL of the Gas Aftercooler	112	108	96	94	92	90	85	82	80	95	
	NR of Noise Control (Attenuation by Courtyard)	0	-2	-3	-4	-6	-7	-8	-8	-8		
	Misc. Atten. (Shielding, Land Contour, Ground Effect)	0	0	0	0	-1	-1	-3	-4	-4		
560	Hemispherical Radiation	-53	-53	-53	-53	-53	-53	-53	-53	-53		
560	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-2	-4	-8		
560	Source Sound Level Contribution	59	53	40	37	32	28	20	13	8	35	
Est'd Total Sound Contribution of the Station at NSA #1		**63**	**57**	**51**	**43**	**37**	**37**	**34**	**27**	**17**	**42.6**	**49.0**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										44.8	70.4
	Est'd Sound Level of Station plus Lowest Ambient Level										**46.9**	**70.4**
	Increase above Lowest Ambient Sound Level (dB)										**2.1**	**0.0**

Table 7: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at Closest NSA (i.e., NSA #1; Residences along Bridge Street, approx. 610 Ft. SSE of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Level) and Potential Increase above Lowest Ambient Sound Level.

Note (1): Lowest ambient sound levels based on the results of a 2015 sound survey by H&K around the site of the Station.

NOTE: Muffler DIL & Equipment PWL values on this spreadsheet should not be used as the specified values. Refer to "Noise Control Measures" section in report or company specifications for actual specified values.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	Calc'd Ldn
	Station A-Wt. Level & SPLs at 610 Ft. (RE: Table 7)	63	57	51	43	37	37	34	27	17	42.6	
900	Hemisph Radiation [20*log(900/610) = 3.4 dB]	-3.4	-3.4	-3.4	-3.4	-3.4	-3.4	-3.4	-3.4	-3.4		
900	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	-1	-2	-4		
Est'd Total Sound Contribution of the Station at NSA #4		**59**	**54**	**47**	**39**	**34**	**33**	**30**	**22**	**10**	**38.9**	**45.3**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										48.5	56.5
	Est'd Sound Level of Station plus Lowest Ambient Level										**48.9**	**56.8**
	Increase above Lowest Ambient Sound Level (dB)										**0.4**	**0.3**

Table 8: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at NSA #4 (i.e., Residences at Vanness Rd. & Monatiquot St., 900 Ft. South of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	Calc'd Ldn
	Station A-Wt. Level & SPLs at 610 Ft. (RE: Table 7)	63	57	51	43	37	37	34	27	17	42.6	
1030	Hemisph Radiation [20*log(1030/610) = 4.6 dB]	-4.6	-4.6	-4.6	-4.6	-4.6	-4.6	-4.6	-4.6	-4.6		
1030	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-1	-3	-6		
Est'd Total Sound Contribution of the Station at NSA #5		**58**	**53**	**46**	**38**	**32**	**31**	**29**	**19**	**7**	**37.5**	**43.9**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										41.3	64.3
	Est'd Sound Level of Station plus Lowest Ambient Level										**42.8**	**64.3**
	Increase above Lowest Ambient Sound Level (dB)										**1.5**	**0.0**

Table 9: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at NSA #5 (i.e., Residences along Kings Cove Way, approx. 1,030 Ft. SE of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	Calc'd Ldn
	Station A-Wt. Level & SPLs at 610 Ft. (RE: Table 7)	63	57	51	43	37	37	34	27	17	42.6	
2300	Hemisph Radiation [20*log(2300/610) = 11.5 dB]	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5	-11.5		
2300	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-3	-5	-13	-23		
Est'd Total Sound Contribution of the Station at NSA #6		**51**	**46**	**39**	**31**	**25**	**22**	**18**	**3**	**0**	**29.3**	**35.7**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										41.4	50.6
	Est'd Sound Level of Station plus Lowest Ambient Level										**41.7**	**50.7**
	Increase above Lowest Ambient Sound Level (dB)										**0.3**	**0.1**

Table 10: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at NSA #6 (i.e., Residences in Area of Evans St. & Rosalind Road, 2,300 Ft. SE of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	
	Station A-Wt. Level & SPLs at 610 Ft. (RE: Table 7)	63	57	51	43	37	37	34	27	17	42.6	
2400	Hemisph Radiation [20*log(2400/610) = 11.9 dB]	-11.9	-11.9	-11.9	-11.9	-11.9	-11.9	-11.9	-11.9	-11.9		Calc'd
2400	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-3	-5	-14	-25		Ldn
Est'd Total Sound Contribution of the Station at NSA #8		**51**	**45**	**39**	**30**	**24**	**22**	**17**	**2**	**0**	**28.9**	**35.3**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										44.5	52.6
	Est'd Sound Level of Station plus Lowest Ambient Level										**44.6**	**52.7**
	Increase above Lowest Ambient Sound Level (dB)										**0.1**	**0.1**

Unweighted SPL in dB per O.B. Center Frequency (Hz)

Table 11: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at NSA #8 (i.e., Residences in the Area of Dee Road, approx. 2,400 Ft. West of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	
	Station A-Wt. Level & SPLs at 610 Ft. (RE: Table 7)	63	57	51	43	37	37	34	27	17	42.6	
4200	Hemisph Radiation [20*log(4200/610) = 16.8 dB]	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8		Calc'd
4200	Atm. Absorption (70% R.H., 60 deg F)	0	0	-1	-1	-3	-5	-11	-27	-49		Ldn
Est'd Total Sound Contribution of the Station at NSA #9		**46**	**40**	**33**	**25**	**18**	**14**	**7**	**0**	**0**	**22.7**	**29.1**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										41.0	49.8
	Est'd Sound Level of Station plus Lowest Ambient Level										**41.1**	**49.8**
	Increase above Lowest Ambient Sound Level (dB)										**0.1**	**0.0**

Unweighted SPL in dB per O.B. Center Frequency (Hz)

Table 12: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at NSA #9 (i.e., Johnson School, approximately 4,200 ESE of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus the Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted PWL or SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	Calc'd Ldn
1)	PWL of Turbine/Compressor inside Building	110	110	112	112	110	110	112	118	112	121	
	Attenuation of the Building	-8	-12	-18	-26	-32	-35	-38	-40	-40		
	Misc. Atten. (Shielding, Land Contour)	0	0	0	0	0	0	0	0	0		
1370	Hemispherical Radiation	-60	-60	-60	-60	-60	-60	-60	-60	-60		
1370	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-2	-4	-10	-19		
1370	Source Sound Level Contribution	41	37	33	25	17	13	9	7	0	22	
2)	PWL of Unsilenced Turbine Exhaust	120	123	120	123	127	119	112	104	96	126	
	Atten. of Noise Control (Custom 2-Silencer System)	-7	-18	-28	-35	-45	-45	-45	-35	-25		
	Misc. Atten. (Shielding, Land Contour)	0	0	0	0	0	0	0	0	0		
1370	Hemispherical Radiation	-60	-60	-60	-60	-60	-60	-60	-60	-60		
1370	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-2	-4	-10	-19		
1370	Source Sound Level Contribution	52	44	31	27	21	12	2	0	0	24	
3)	PWL of Aboveground Piping & Components	98	98	102	95	96	105	110	108	100	114	
	Atten. of Noise Control (Insulation & Courtyard Effect)	4	4	0	-4	-10	-15	-18	-20	-20		
	Misc. Atten. (Shielding, Land Contour)	0	0	0	0	0	0	0	0	0		
1370	Hemispherical Radiation	-60	-60	-60	-60	-60	-60	-60	-60	-60		
1370	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-2	-4	-10	-19		
1370	Source Sound Level Contribution	41	41	41	30	25	28	27	17	1	33	
4)	PWL of LO Cooler	105	100	94	90	88	84	80	78	75	90	
	NR of Noise Control	0	0	0	0	0	0	0	0	0		
	Misc. Atten. (Shielding, Land Contour)	0	0	0	0	0	0	0	0	0		
1370	Hemispherical Radiation	-60	-60	-60	-60	-60	-60	-60	-60	-60		
1370	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-2	-1	-2	-4	-10	-19		
1370	Source Sound Level Contribution	44	39	33	28	27	22	15	7	0	28	
5)	PWL of Unsilenced Turbine Air Intake	108	114	120	121	122	124	129	152	144	153	
	Attenuation of Intake Silencer System ("Custom")	-2	-5	-12	-15	-30	-45	-50	-60	-60		
	Attenuation of Air Intake Filter	-1	-6	-12	-18	-22	-25	-25	-25	-20		
	Misc. Atten. (Shielding, Land Contour)	0	0	0	0	0	0	0	0	0		
1370	Hemispherical Radiation	-60	-60	-60	-60	-60	-60	-60	-60	-60		
1370	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-2	-4	-10	-19		
1370	Source Sound Level Contribution	44	42	35	27	9	0	0	0	0	23	
6)	PWL of the Gas Aftercooler	112	108	96	94	92	90	85	82	80	95	
	NR of Noise Control (Attenuation by Courtyard)	0	-2	-3	-4	-6	-7	-8	-8	-8		
	Misc. Atten. (Shielding or Ground Effect)	0	0	0	0	0	0	0	0	0		
1370	Hemispherical Radiation	-60	-60	-60	-60	-60	-60	-60	-60	-60		
1370	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-1	-1	-2	-4	-10	-19		
1370	Source Sound Level Contribution	51	45	32	29	25	21	12	3	0	27	
Est'd Total Sound Contribution of the Station at NSA #2		**56**	**50**	**44**	**36**	**31**	**29**	**28**	**18**	**1**	**35.7**	**42.1**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										46.8	54.9
	Est'd Sound Level of Station plus Lowest Ambient Level										**47.1**	**55.1**
	Increase above Lowest Ambient Sound Level (dB)										**0.3**	**0.2**

Table 13: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at the Closest NSA with Water Body between the CS Site and the NSA (i.e., NSA #2; Residences in the Area of Germantown Point, approx. 1,370 Ft. North of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Note (1): Lowest ambient sound levels based on the results of a 2015 sound survey by H&K around the site of the Station.

NOTE: Muffler DIL & Equipment PWL values on this spreadsheet should <u>not</u> be used as the specified values. Refer to "Noise Control Measures" section in report or other company specifications for actual specified values.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	
	Station A-Wt. Level & SPLs at 1,370 Ft. (RE: Table 13)	56	50	44	36	31	29	28	18	1	35.7	
1560	Hemisph Radiation [20*log(1560/1370) = 1.1 dB]	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1	-1.1		Calc'd
1560	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	-1	-1	-3		Ldn
Est'd Total Sound Contribution of the Station at NSA #3		**55**	**49**	**43**	**35**	**30**	**28**	**26**	**16**	**0**	**34.4**	**40.8**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										44.0	54.0
	Est'd Sound Level of Station plus Lowest Ambient Level										**44.4**	**54.2**
	Increase above Lowest Ambient Sound Level (dB)										**0.4**	**0.2**

Table 14: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at another NSA with Water Body between the Station Site and the NSA (i.e., NSA #3; Residences along King's Cove Beach Road, approx. 1,560 Ft. East of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Sound Level) and Potential Increase above Lowest Ambient Sound Level.

Source No. & Dist. (Ft.)	Noise Sources and Other Conditions/Factors associated with Acoustical Analysis	Unweighted SPL in dB per O.B. Center Frequency (Hz) 31.5	63	125	250	500	1000	2000	4000	8000	A-Wt. Level	
	Station A-Wt. Level & SPLs at 1,370 Ft. (RE: Table 13)	56	50	44	36	31	29	28	18	1	35.7	
1970	Hemisph Radiation [20*log(1970/1370) = 3.2 dB]	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2	-3.2		Calc'd
1970	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	-1	-2	-5	-8		Ldn
Est'd Total Sound Contribution of the Station at NSA #7		**53**	**47**	**41**	**32**	**27**	**25**	**23**	**10**	**0**	**31.8**	**38.2**
	Measured Lowest Ambient L90 and Ldn at NSA: Note (1)										39.3	49.1
	Est'd Sound Level of Station plus Lowest Ambient Level										**40.0**	**49.4**
	Increase above Lowest Ambient Sound Level (dB)										**0.7**	**0.3**

Table 15: Weymouth Compressor Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit) at another NSA with Water Body between the Station Site and the NSA (i.e., NSA #7; Residences at Fore River Ave. & Weybossett St., approx. 1,970 Ft. ENE of the Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Level) and Potential Increase above Lowest Ambient Sound Level.

Source No.	Noise Sources and Other Conditions/Factors	Unweighted PWL or SPL in dB per O.B. Center Frequency (Hz)									A-Wt.
& Dist. (Ft.)	associated with Acoustical Analysis	31.5	63	125	250	500	1000	2000	4000	8000	Level
1)	PWL of Turbine/Compressor inside Building	110	110	112	112	110	110	112	118	112	121
	Attenuation of the Building	-8	-12	-18	-28	-35	-38	-40	-45	-45	
	Misc. Atten. (Shielding or Effect of Courtyard Wall)	0	0	0	0	0	0	0	0	0	
100	Hemispherical Radiation	-38	-38	-38	-38	-38	-38	-38	-38	-38	
100	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	0	-1	-1	
100	Source Sound Level Contribution	64	60	56	46	37	34	34	35	28	45
2)	PWL of Unsilenced Turbine Exhaust	120	123	120	123	127	119	112	104	96	126
	Atten. of Noise Control (Custom 2-Silencer System)	-7	-18	-28	-35	-45	-45	-45	-35	-25	
	Misc. Atten. (Stack Directivity)	-1	-2	-2	-3	-5	-8	-9	-10	-10	
150	Hemispherical Radiation	-41	-41	-41	-41	-41	-41	-41	-41	-41	
150	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	0	-1	-2	
150	Source Sound Level Contribution	71	62	49	44	36	25	16	17	18	41
3)	PWL of Aboveground Piping & Components	98	98	102	95	96	105	110	108	100	114
	Atten. of Noise Control (Insulation & Courtyard Effect)	4	4	0	-2	-8	-12	-16	-18	-18	
	Misc. Atten. (Shielding or Effect of Courtyard Wall)	-2	-4	-6	-8	-12	-14	-16	-18	-18	
130	Hemispherical Radiation	-40	-40	-40	-40	-40	-40	-40	-40	-40	
130	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	0	-1	-2	
130	Source Sound Level Contribution	60	58	56	45	36	39	38	31	22	45
4)	PWL of LO Cooler	105	100	94	90	88	84	80	78	75	90
	NR of Noise Control	0	0	0	0	0	0	0	0	0	
	Misc. Atten. (Shielding or Effect of Courtyard Wall)	0	0	0	0	-1	-1	-2	-3	-3	
120	Hemispherical Radiation	-39	-39	-39	-39	-39	-39	-39	-39	-39	
120	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	-2	0	0	0	-1	-2	
120	Source Sound Level Contribution	66	61	55	49	48	44	38	35	31	49
5)	PWL of Unsilenced Turbine Air Intake	108	114	120	121	122	124	129	152	144	153
	Attenuation of Intake Silencer System ("Custom")	-2	-5	-12	-15	-30	-45	-50	-60	-60	
	Attenuation of Air Intake Filter	-1	-6	-12	-18	-22	-25	-25	-25	-20	
	Misc. Atten. (Shielding or Effect of Courtyard Wall)	0	0	0	0	-1	-2	-4	-5	-5	
140	Hemispherical Radiation	-41	-41	-41	-41	-41	-41	-41	-41	-41	
140	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	0	-1	-2	
140	Source Sound Level Contribution	64	62	55	47	28	11	9	20	16	43
6)	PWL of the Gas Aftercooler	112	108	96	94	92	90	85	82	80	95
	NR of Noise Control	0	0	0	0	0	0	0	0	0	
	Misc. Atten. (Shielding or Effect of Courtyard Wall)	-2	-4	-6	-8	-12	-14	-16	-18	-18	
160	Hemispherical Radiation	-42	-42	-42	-42	-42	-42	-42	-42	-42	
160	Atm. Absorption (70% R.H., 60 deg F)	0	0	0	0	0	0	0	-1	-2	
160	Source Sound Level Contribution	68	62	48	44	38	34	27	21	18	42
Total Sound Contribution of Station at Closest Property Line		**75**	**69**	**62**	**54**	**49**	**46**	**42**	**39**	**33**	**53.0**

Meas'd Lowest Ambient L90 at Property Line: Note (1)	47.8
Est'd Sound Level of Station plus Lowest Ambient Level	**54.2**
Est'd Station Sound Level above the Lowest Ambient L90	**5.2**

Table 16: Algonquin Weymouth Station: Est'd Sound Contribution of the Station (i.e., Solar Taurus 60 Turbine-Driven Compressor Unit #1 & Gas Aftercooler) at Closest Station Property Line (i.e., East Property Limit 100 Ft. East of Compressor Building), Total Cumulative Sound Level (i.e., Station Level plus Lowest Ambient Level) and Potential Increase above Lowest Ambient Sound Level.

Note (1): Lowest ambient sound levels based on the results of a 2016 sound survey by H&K around property line of Station.

DESCRIPTION OF ACOUSTICAL ANALYSIS METHODOLOGY AND SOURCE OF SOUND DATA

Analysis Methodology: In general, the predicted sound level contributed by the Station was calculated as a function of frequency from estimated octave-band (O.B.) sound power levels (PWLs) for each significant Station sound source. The following summarizes the acoustical analysis procedure:

- Initially, unweighted O.B. PWLs of the significant noise sources associated with the compressor unit and Station were determined from actual sound level measurements performed by H&K at similar type of facilities and/or from acceptable equipment supplier data/tests;

- Then, expected noise reduction (NR) or attenuation in dB per O.B. frequency due to any noise control measures, hemispherical sound propagation (discussed in more detail below*) and atmospheric sound absorption (discussed in more detail below**) were subtracted from the unweighted O.B. PWLs to obtain the unweighted O.B. SPLs of each noise source;

- Finally, the resulting estimated O.B. SPLs for all noise sources associated with the Station (with noise control and other sound attenuation effects) were logarithmically summed, and the total O.B. SPLs for all noise sources were corrected for A-weighting to provide the estimated overall A-wt. sound level contributed by the compressor unit at the closest NSA. The predicted sound contribution of the compressor unit at the closest NSA was utilized to estimate the station noise contribution at the other nearby NSAs that are more distant that the closest NSA.

*Sound propagates outwards in all directions (i.e., length, width, height) from a point source, and the sound energy of a noise source decreases with increasing distance from the source. In the case of hemispherical sound propagation, the source is located on a flat continuous plane/surface (e.g., ground), and the sound radiates hemispherically (i.e., outward, over and above the surface) from the source. The following equation is the theoretical decrease of sound energy when determining the resulting SPL of a noise source at a specific distance ("r") of a receiver from a source PWL:

- Decrease in SPL ("hemispherical propagation") from a noise source = **20*log(r) – 2.3 dB** (where "r" is distance of the receiver from the noise source)

Since the analysis methodology incorporates hemispherical sound propagation, this methodology is actually more applicable to sound propagation over "acoustically-hard" surfaces, such as concrete or water. Therefore, for those receptors in which there is a water body between the receptor and the Station, we believe that the noise modeling accounts for the sound propagation over water although temporary temperature inversion conditions could elevate sound levels at a receptor located across a body of water but there is no reliable "industrial standard" method to predict the frequency and duration of these inversions as well as the degree of sound level elevation (RE: ISO 9613[3]). For receptors in which there is mostly land between the receptor and Station, existing topography, ground effect and shielding by structures-roadways can influence the sound contributed by the Station at a receptor. Therefore, if applicable, the attenuation due to topography, ground effect and/or shielding effect was included for those receptors with land between the receptor and Station. The sound attenuation effect due to foliage/trees

[3]ISO Standard 9613-1 1993 (E) & ISO Standard 9613-2: 1996 (E), entitled "Acoustics – Attenuation of sound during propagation outdoors – Part 1: Calculation of the absorption of sound by the atmosphere; and Part 2: General method of calculation".

was not considered in the analysis since there is minimal foliage between the Station and the identified closest receptors/NSAs.

Air absorbs sound energy, and the amount of absorption ("attenuation") is dependent on temperature and relative humidity (R.H.) of air and frequency of sound. For example, the attenuation due to air absorption for 1000 Hz octave band SPL is approximately **1.5 dB per 1,000 feet for standard day conditions (i.e., no wind, 59 deg. F. and 70% R.H.).

Analysis and Methodology (Noise Attributable to a Unit Blowdown Event): The noise resulting from a blowdown event was estimated by using the "inverse-square law" and included some attenuation due to atmospheric sound absorption. Consequently, the estimated noise of a blowdown event at the receptor (i.e., closest NSA) was calculated as follows:

SPL (receptor) = (Blowdown SPL at R1) – 20*log(R2/R1) – Atm. Atten. = **55 dBA** – 20*log (700/300) – 2 dB = **46 dBA**

Where: R1 = Distance of Specified Blowdown Noise Level Requirement (i.e., 300 ft.)
R2 = Distance of the Closest Receptor (NSA #1) from the Blowdown Silencer (700 ft.)

Source of Sound Data: The following describes the source of sound data for estimating the source sound levels and source PWLs used in the acoustical analysis. Note that equipment noise levels utilized in the acoustical analysis (i.e., spreadsheet analysis) are generally higher than the sound level requirement for the equipment to insure that the design incorporates an acoustical "margin of safety."

(1) PWL values of the specific equipment inside the building (i.e., noise of turbine/compressor) was calculated from sound data measured by H&K on similar type of gas compressor installation;

(2) Turbine exhaust PWL values were calculated from sound data provided in Solar Noise Prediction Manual and sound data measured by H&K on a similar turbine installation;

(3) Noise radiated from gas piping is primarily a result the noise generated by the gas compressor. Consequently, measurement of both near field and far field sound data on gas piping is assumed to be an accurate method of quantifying the noise associated with the new gas piping, and the estimated PWL values for gas piping used in the analysis were determined from near field and far field sound data by H&K on a similar type of compressor to that of the planned compressor unit.

(4) PWL values for Station coolers were designated to meet the design noise goal. Note that the estimated PWL for the cooler utilized in the acoustical analysis assumes some noise associated with piping associated with the coolers. The noise level for the cooler(s) used in the acoustical analysis is generally higher than the sound level requirement in order that the noise design analysis incorporates an acoustical "margin of safety." In addition, there can be other noise associated with the cooler that is not directly related to the operation of the cooler fans.

(5) PWL values for the turbine air intake were calculated from sound data in Solar Noise Prediction Manual, although the low-frequency SPLs were modified as a result of field tests by H&K;

(6) Estimated A-wt. sound level of a unit blowdown event, via a blowdown vent/silencer, was calculated from sound data measured by H&K on similar type of blowdown operations.

Type of Equipment	Equipment Power Rating or Capacity	Est'd Number Required	Est'd A-Wt. Sound Level at 50 Ft.: Note (1)	Resulting A-Wt. PWL of Single Piece of Equip.	Assumed Max. No. Operating at One Time	Est'd Max. A-Wt. PWL or Sound Level of Equip.	
Diesel Generator	250 to 400 HP	1 to 2	65 - 70 dBA	102 dBA	1	102	
Bulldozer	250 to 700 HP	1 to 2	75 - 80 dBA	110 dBA	1	110	
Grader	450 to 600 HP	1 to 2	70 - 75 dBA	105 dBA	1	105	
Backhoe	130 to 210 HP	1 to 2	65 - 72 dBA	104 dBA	1	104	
Front End Loader	150 to 250 HP	1 to 2	65 - 70 dBA	102 dBA	1	102	
Truck Loaded	40 Ton	As needed	70 - 75 dBA	105 dBA	1	105	
	Est'd Total Maximum A-Wt. PWL (dBA) of Construction Site Equipment					113	Calc'd
	Atten. (dB) due to Hemispherical Sound Propagation (650 Ft.): Note (2)					-54	Ldn
	Est'd Attenuation (in dB) due to Air Absorption and Topography: Note (3)					-3	Note (4)
	Est'd A-Wt. Sound Level (dBA) at the Closest NSA Considering a Maximum Number of Equipment Operating at One Time					56 dBA	54 dBA

Table 17: **Algonquin Weymouth Station: Est'd Sound Contribution at the Closest NSA (i.e., approx. 650 Ft. SSE of Site) during Construction Activity at the Site of the Compressor Station. Sound Contribution assumes Operation of the "Loudest" Equipment during a Time Frame with the Largest Amount of Equipment Operating (e.g., Site Grading & Clearing/Grubbing)**

Note (1): Noise Emission Levels of construction equipment based on an EPA Report (meas'd sound data for a railroad construction project) and measured sound data in the field by H&K or other published sound data.

Note (2): Noise attenuation due to hemispherical sound propagation: Sound propagates outwards in all directions (i.e., length, width, height) from a point source, and the sound energy of a noise source decreases with increasing distance from the source. In the case of hemispherical sound propagation, the source is located on a flat continuous plane/surface (e.g., ground), and the sound radiates hemispherically from the source.

The following equation is the theoretical decrease of sound energy when determining the resulting SPL of a noise source at a specific distance (“r”) of a receiver from a source sound power level (PWL):

Decrease in SPL (“hemispherical propagation”) from a noise source = 20*log(r) – 2.3 dB, where “r” is distance of the receiver from the noise source. For example, if the distance "r" is 650 feet between the site and closest NSA, the “hemispherical propagation” = **20*log(650) – 2.3 dB** = **54 dB**.

Note (3): Noise attenuation due to air absorption, foliage, shielding, topography: Air absorbs sound energy and amount of absorption ("attenuation") is dependent on temperature & relative humidity (R.H.) of the air and frequency of sound. For standard day conditions (i.e., no wind, 60 deg. F. and 70% R.H.), the attenuation due to air absorption for the medium frequency” (i.e., 1000 Hz octave band SPL) is approximately **1.5 dB** per 1,000 feet. In addition, foliage, shielding an topography between the Station and receptors/NSAs, can have a sound attenuation effect. For example, the "medium-frequency" attenuation (i.e., 1000 Hz) due to forest greater than 500 feet thick is approximately **10 dB**. For this site, there will be existing topography (berm) between the Station and closest NSA that should provide a minimum of **2 dB** attenuation; adding to the air absorption attenuation (approx. **1 dB**), an overall attenuation of **3 dB** was utilized as the estimated attenuation due to air absorption and existing topography.

Note (4): Calc'd Ldn is approx. 2 dB lower than A-wt. sound level since construction activities will occur only during daytime.

ANALYSIS METHODOLOGY AND SOURCE OF SOUND DATA (CONSTRUCTION ACTIVITIES)

The predicted sound level contributed by the construction-related activity (i.e., construction of the compressor station) was calculated from estimated A-wt. PWL of noise sources (i.e., construction equipment noise) that typically operate during the specific construction activity. The following summarizes the acoustical analysis procedure utilized for the construction activity at the site:

- Initially, the A-wt. PWL of noise sources associated with the construction activity were determined from published sound data and/or actual sound level measurements by H&K, and the total PWL of each noise source (equipment) was based on the anticipated number of equipment operating;

- Next, A-wt. PWL of all sources were logarithmically summed to provide the overall A-wt. PWL contributed by construction activity. It is assumed that the highest level of construction noise would occur during site earth work (i.e., time frame when largest amount of equipment operate);

- Finally, the estimated A-wt. sound level of the construction activity at the specific distance was determined by compensating for sound attenuation due to propagation (hemispherical radiation), atmospheric sound absorption and any sound attenuation effect of foliage/topography***.

The noise levels of construction equipment were based on an EPA Report (i.e., measured sound data from railroad construction equipment taken during the Northeast Corridor Improvement Project) that was summarized in a 1995 Report to the Federal Transit Administration as prepared by Harris Miller Miller & Hanson Inc. Also, construction equipment noise levels listed in an article in the Journal of Noise Control Engineering and sound data measured by H&K was utilized. The following list some references used by H&K to determine construction equipment noise emission levels:

(1) "Transit Noise and Vibration Impact Assessment", dated April 1995, prepared by Harris Miller Miller & Hanson Inc. for the Office of Planning of the Federal Transit Administration.
(2) Erich Thalheimer, "Construction Noise Control Program and Mitigation Strategy at the Central Artery/Tunnel Project", J of Noise Control Eng., 48 (5), pp. 157-165 (2000 Sep-Oct).
(3) "Noise Control for Building Manufacturing Plant Equipment and Products", course handout notes for a noise course given each year by Hoover & Keith Inc.

***Discussion of noise attenuation due to foliage, shielding and/or existing topography: Foliage, shielding and existing topography between a Station and receptors/NSAs, can have a sound attenuation effect. For example, based on our experience and ISO Standard, (previously referenced ISO Standard 9613-1 & ISO Standard 9613-2) the "medium-frequency" attenuation (1000 Hz) due to foliage/trees greater than 500 feet thick is approximately **10 dB**. For this Station site, there will be minimal foliage between the site and closest receptors, but there is existing topography (berm/mound) between the Station and closest NSA that should provide a minimum of **2 dB** attenuation; adding attenuation due to air absorption (approx. **1 dB**) to the attenuation due to the topography, an overall attenuation of **3 dB** was utilized as the attenuation due to air absorption and existing topography.

End of Report

ATTACHMENT G: DETAILED EMISSIONS CALCULATIONS AND MANUFACTURER SPECIFICATIONS

TABLE B-1Aa Ambient Temperature, Start Model, and Utilization Data *PTE - 100% Fuel Utilization at 100% Power Output*			
Month	#Days	Daily Average	Weighted Daily Average
JAN	31.00	22.85	1.94
FEB	28.50	24.75	1.93
MAR	31.00	33.65	2.85
APR	30.00	44.35	3.64
MAY	31.00	55.50	4.71
JUN	30.00	64.20	5.27
JUL	31.00	69.70	5.91
AUG	31.00	67.95	5.76
SEP	30.00	60.10	4.93
OCT	31.00	50.00	4.24
NOV	30.00	39.35	3.23
DEC	31.00	27.40	2.32
Annual	365.50	46.65	**46.74**
Low Temperature Data			
Below 0˚F Hours		12 hrs/yr	
Below -20˚F Hours		0 hrs/yr	
NOTES			
1. Please refer to TABLE B-0.			
Start Model and Utilization			
Utilization		100.00%	
Start Model		AGT - Medium	
Starts		416.00 starts/yr	

TABLE B-1Ab
Manufacturer's Operating and Emissions Data
Normal Operations
PTE - 100% Fuel Utilization at 100% Power Output

Parameters			Curve Fitting			Vendor Data						
Ambient	Temperature	°F	-20.00	-20.00	46.65	-0.01	0.01	20.00	40.00	60.00	80.00	100.00
	Altitude	ft	0	0	0	0	0	0	0	0	0	0
	Pressure	psia	14.702	14.702	14.702	14.702	14.702	14.702	14.702	14.702	14.702	14.702
	Relative Humidity	%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%
	Specific Humidity	$lb_{H2O}/lb_{Dry\ Air}$	0.0003	0.0003	0.0035	0.0006	0.0006	0.0013	0.0028	0.0058	0.0124	0.0262
Fuel	Lower Heating Value (LHV)	BTU/scf	939.2	939.2	939.2	939.2	939.2	939.2	939.2	939.2	939.2	939.2
	Higher Heating Value (HHV)	BTU/scf	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6
Turbine	Net Output Power	hp	8,664	8,664	7,758	8,414	8,414	8,164	7,876	7,473	6,883	6,242
	Fuel Consumption	scf/hr	71,786	71,786	66,080	70,241	70,241	68,697	66,823	64,342	60,850	57,261
	Heat Input at LHV	MMBTU/hr	67.42	67.42	62.06	65.97	65.97	64.52	62.76	60.43	57.15	53.78
	Heat Input at HHV	MMBTU/hr	74.91	74.91	68.96	73.30	73.30	71.69	69.73	67.14	63.50	59.76
	Heat Rate at LHV	BTU/hp-hr	7,782	7,782	8,000	7,841	7,841	7,903	7,969	8,086	8,303	8,616
	Heat Rate at HHV	BTU/hp-hr	8,646	8,646	8,889	8,712	8,712	8,781	8,854	8,985	9,226	9,573
Exhaust	Temperature	°F	865	865	943	889	889	913	936	957	976	999
	Water Fraction	%, by vol	5.67%	5.67%	6.38%	5.82%	5.82%	5.97%	6.25%	6.75%	7.67%	9.34%
	Non-Water Fraction	%, by vol	94.33%	94.33%	93.62%	94.18%	94.18%	94.03%	93.75%	93.25%	92.33%	90.66%
	O_2 Content	%, by vol (dry)	15.42%	15.42%	15.34%	15.39%	15.39%	15.36%	15.34%	15.34%	15.36%	15.36%
	Molecular Weight	lb/lb-mol	28.62	28.62	28.53	28.60	28.60	28.58	28.55	28.49	28.39	28.20
	Flow Rate	lb/hr	192,068	192,068	174,087	186,881	186,881	181,699	176,118	169,591	161,072	151,663
		scfm (1 atm, 68°F)	43,161	43,161	39,209	42,000	42,000	40,880	39,649	38,247	36,473	34,566
		acfm	108,268	108,268	104,162	107,265	107,265	106,263	104,789	102,604	99,157	95,478
NO_X Emissions		lb/lb-mol	46.01	46.01	46.01	46.01	46.01	46.01	46.01	46.01	46.01	46.01
		ppmvd, 15% O_2	120	42	9	42	9	9	9	9	9	9
		ppmvw	105.14	36.80	7.94	36.94	7.92	7.95	7.95	7.91	7.80	7.66
		lb/hr	32.46	11.36	2.23	11.11	2.38	2.32	2.26	2.17	2.04	1.90
CO Emissions		lb/lb-mol	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01	28.01
		ppmvd, 15% O_2	150	100	25	100	25	25	25	25	25	25
		ppmvw	131.42	87.61	22.06	87.95	21.99	22.07	22.09	21.97	21.67	21.28
		lb/hr	24.70	16.47	3.77	16.10	4.02	3.93	3.82	3.66	3.44	3.21
UHC Emissions		lb/lb-mol	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37	18.37
		ppmvd, 15% O_2	75	50	25	50	25	25	25	25	25	25
		ppmvw	65.71	43.81	22.06	43.98	21.99	22.07	22.09	21.97	21.67	21.28
		lb/hr	8.10	5.40	2.47	5.28	2.64	2.58	2.50	2.40	2.26	2.10

NOTES

1. Operating and emissions data was provided by the manufacturer for the following ambient temperatures: 0°F, 20°F, 40°F, 60°F, 80°F, and 100°F.
   Specific Humidity is estimate using curve fitting equation: $6.15E\text{-}04e^{3.75E\text{-}02T}$
   All other parameter values estimated using cubic spline.
2. Pollutant concentrations (ppmvd at 15% O2) for 0°F and -20°F based on information provided in a document published by the manufacturer.
3. Ambient pressure and humidity will vary. However, it is believed that any variation would not affect compliance with the proposed emission representations.
4. The heating value of the natural gas used to fuel the turbine will vary. However, it is believed that any variation would not affect compliance with the proposed emission representations.

TABLE B-1Ab
Manufacturer's Operating and Emissions Data
Normal Operations
PTE - 100% Fuel Utilization at 100% Power Output

Vendor Data

Make:	Solar										
Model:	060-07802S4										
Rate	7,700 hp (ISO)										
Capacity:	6,800 hp (NEMA)										
Load:	100%										
Ambient	Temperature	°F			-0.01	0.01	20.00	40.00	60.00	80.00	100.00
	Specific Humidity	$lb_{H2O}/lb_{Dry\ Air}$			0.0006	0.0006	0.0014	0.0031	0.0066	0.0133	0.0253
Fuel	Lower Heating Value (LHV)	BTU/scf			939.2	939.2	939.2	939.2	939.2	939.2	939.2
Turbine	Net Output Power	hp			8,414	8,414	8,164	7,876	7,473	6,883	6,242
	Heat Input at LHV	MMBTU/hr			65.97	65.97	64.52	62.76	60.43	57.15	53.78
Exhaust	Temperature	°F			889	889	913	936	957	976	999
	Water Fraction	%			5.82%	5.82%	5.97%	6.25%	6.75%	7.67%	9.34%
	O_2 Content	% (dry)			15.39%	15.39%	15.36%	15.34%	15.34%	15.36%	15.36%
	Molecular Weight	lb/lb-mol			28.60	28.60	28.58	28.55	28.49	28.39	28.20
	Flow Rate	lb/hr			186,881	186,881	181,699	176,118	169,591	161,072	151,663
		acfm			107,265	107,265	106,263	104,789	102,604	99,157	95,478
Guaranteed	NO_X	ppmvd, 15% O_2	120	42	42	9	9	9	9	9	9
Emissions	CO	ppmvd, 15% O_2	150	100	100	25	25	25	25	25	25
	UHC	ppmvd, 15% O_2	75	50	50	25	25	25	25	25	25

TABLE B-1Ac
Gas-Fired Turbines
Emission Estimates
Normal Operations
PTE - 100% Fuel Utilization at 100% Power Output

Make	Solar				
Model	060-07802S4				
Normal Operating Load	100%				
Fuel	Natural Gas				
Fuel Higher Heating Value (HHV)	1,020 BTU/scf			1,020 BTU/scf	
Ambient Temperature	46.65 °F			0.01 °F	
Power Output	7,758 bhp (mech.)			8,414 bhp (mech.)	
	5,785 kW (elec.)			6,274 kW (elec.)	
Heat Rate at HHV	8,889 BTU/hp-hr			8,712 BTU/hp-hr	
Operating Hours	8,760 hrs/yr				
Fuel Consumption	67,606 scfh			71,863 scfh	
	592.230 MMscf/yr				
Heat Input at HHV	68.96 MMBTU/hr			73.30 MMBTU/hr	
	604,075 MMBTU/yr	Average	Maximum		Maximum
NO_X	32.97 lb/MMscf	2.2288 lb/hr	9.7621 tpy	33.12 lb/MMscf	2.3799 lb/hr
CO	55.75 lb/MMscf	3.7690 lb/hr	16.5082 tpy	56.00 lb/MMscf	4.0245 lb/hr
SO_2	14.29 lb/MMscf	0.9658 lb/hr	4.2302 tpy	14.29 lb/MMscf	1.0266 lb/hr
$PM_{10/2.5}$	6.73 lb/MMscf	0.4551 lb/hr	1.9934 tpy	6.73 lb/MMscf	0.4838 lb/hr
$CO_{2\text{-}e}$	120,800 lb/MMscf	8,167 lb/hr	35,771 tpy	120,803 lb/MMscf	8,681 lb/hr
CO_2	120,017 lb/MMscf	8,114 lb/hr	35,539 tpy	120,017 lb/MMscf	8,625 lb/hr
N_2O	0.23 lb/MMscf	0.0153 lb/hr	0.0670 tpy	0.23 lb/MMscf	0.0163 lb/hr
TOC (Total)	36.57 lb/MMscf	2.4721 lb/hr	10.8278 tpy	36.73 lb/MMscf	2.6397 lb/hr
Methane	28.59 lb/MMscf	1.9327 lb/hr	8.4653 tpy	28.72 lb/MMscf	2.0637 lb/hr
Ethane	1.00 lb/MMscf	0.0674 lb/hr	0.2953 tpy	1.00 lb/MMscf	0.0720 lb/hr
VOC (Total)	6.98 lb/MMscf	0.4719 lb/hr	2.0671 tpy	7.01 lb/MMscf	0.5039 lb/hr
VOC (non-HAP)	3.57 lb/MMscf	0.2411 lb/hr	1.0559 tpy	3.58 lb/MMscf	0.2574 lb/hr
HAP (Total)	3.42 lb/MMscf	0.2309 lb/hr	1.0112 tpy	3.43 lb/MMscf	0.2465 lb/hr
Acetaldehyde	1.33E-01 lb/MMscf	0.0090 lb/hr	0.0394 tpy	1.34E-01 lb/MMscf	0.0096 lb/hr
Acrolein	2.13E-02 lb/MMscf	0.0014 lb/hr	0.0063 tpy	2.14E-02 lb/MMscf	0.0015 lb/hr
Benzene	3.99E-02 lb/MMscf	0.0027 lb/hr	0.0118 tpy	4.01E-02 lb/MMscf	0.0029 lb/hr
Biphenyl					
Butadiene (1,3-)	1.43E-03 lb/MMscf	0.0001 lb/hr	0.0004 tpy	1.44E-03 lb/MMscf	0.0001 lb/hr
Carbon Tetrachloride					
Chlorobenzene					
Chloroform					
Dichloropropene (1,3-)					
Ethylbenzene	1.06E-01 lb/MMscf	0.0072 lb/hr	0.0315 tpy	1.07E-01 lb/MMscf	0.0077 lb/hr
Ethylene Dibromide					
Formaldehyde	2.36E+00 lb/MMscf	0.1596 lb/hr	0.6989 tpy	2.37E+00 lb/MMscf	0.1704 lb/hr
Hexane (n-)					
Methanol					
Methylene Chloride					
Methylnaphthalene (2-)					
Naphthalene	4.32E-03 lb/MMscf	0.0003 lb/hr	0.0013 tpy	4.34E-03 lb/MMscf	0.0003 lb/hr
PAH	7.31E-03 lb/MMscf	0.0005 lb/hr	0.0022 tpy	7.35E-03 lb/MMscf	0.0005 lb/hr
Phenol					
Propylene Oxide	9.64E-02 lb/MMscf	0.0065 lb/hr	0.0285 tpy	9.68E-02 lb/MMscf	0.0070 lb/hr
Styrene					
Tetrachloroethane (1,1,2,2-)					
Toluene	4.32E-01 lb/MMscf	0.0292 lb/hr	0.1280 tpy	4.34E-01 lb/MMscf	0.0312 lb/hr
Trichloroethane (1,1,2-)					
Trimethylpentane (2,2,4-)					
Vinyl Chloride					
Xylenes	2.13E-01 lb/MMscf	0.0144 lb/hr	0.0630 tpy	2.14E-01 lb/MMscf	0.0154 lb/hr

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Manufacturer provided operating and emissions data (TABLE B-1Ab).
3. The annual emissions are based on a representative annual average ambient temperature (TABLE B-1Aa).
   Maximum hourly emissions are based on an ambient temperature of 0°F.
4. NOX, CO, and TOC (Total) emission factor based on Vendor Guarantee.
5. CO2 and N2O emission factors based on 40 CFR 98, Subpart C, Table C-1 and 40 CFR 98, Subpart C, Table C-2, respectively.
6. SO2 emission factor based on AP-42, Section 3.1 (Revised 4/00), Table 3.1-2a using Tariff (5 gr/100 scf).
7. PM10/2.5 emission factor based on AP-42, Section 3.1 (Revised 4/00), Table 3.1-2a, not Solar's PIL 171 dated 5/6/2015 (which is 127% greater).
8. Methane, Ethane, and VOC (Total) emissions based on scaling of AP-42, Section 3.1 (Revised 4/00), Table 3.1-2a using Vendor Guarantee.
   Speciated VOC (non-HAP) emissions based on scaling of AP-42, Section 3.1 (Revised 4/00), Table 3.1-2a using Vendor Guarantee.
   $EF_{Scaled} = (EF_{AP42})(EF_{TOC}/EF_{TOC\text{-}AP42})$

TABLE B-1Ad
Manufacturer's Operating and Emissions Data
Startup/Shutdown Step 2: Iginition-Idle
PTE - 100% Fuel Utilization at 100% Power Output

Parameters			Interpolated	Vendor Data					
Ambient	Temperature	°F	46.65	0.01	20.00	40.00	60.00	80.00	100.00
	Altitude	ft	0	0	0	0	0	0	0
	Pressure	psia	14.702	14.702	14.702	14.702	14.702	14.702	14.702
	Relative Humidity	%	60%	60%	60%	60%	60%	60%	60%
	Specific Humidity	$lb_{H2O}/lb_{Dry\ Air}$	0.0035	0.0006	0.0013	0.0028	0.0058	0.0124	0.0262
Fuel	Lower Heating Value (LHV)	BTU/scf	939.2	939.2	939.2	939.2	939.2	939.2	939.2
	Higher Heating Value (HHV)	BTU/scf	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6
Turbine	Net Output Power	hp	776	841	816	788	747	688	624
	Fuel Consumption	scf/hr	15,546	15,534	15,534	15,577	15,385	15,002	14,566
	Heat Input at LHV	MMBTU/hr	14.60	14.59	14.59	14.63	14.45	14.09	13.68
	Heat Input at HHV	MMBTU/hr	16.22	16.21	16.21	16.26	16.06	15.66	15.20
	Heat Rate at LHV	BTU/hp-hr	18,815	17,348	17,880	18,566	19,344	20,480	21,923
	Heat Rate at HHV	BTU/hp-hr	20,905	19,276	19,867	20,629	21,493	22,755	24,359
Exhaust	Temperature	°F	598	503	543	584	626	670	715
	Water Fraction	%, by vol	3.32%	2.56%	2.78%	3.15%	3.79%	4.89%	6.76%
	Non-Water Fraction	%, by vol	96.68%	97.44%	97.22%	96.85%	96.21%	95.11%	93.24%
	O_2 Content	%, by vol (dry)	18.40%	18.63%	18.54%	18.44%	18.33%	18.23%	18.10%
	Molecular Weight	lb/lb-mol	28.72	28.80	28.78	28.74	28.68	28.56	28.36
	Flow Rate	lb/hr	81,619	96,424	92,838	83,262	78,987	74,120	68,816
		scfm (1 atm, 68°F)	18,305	21,528	20,744	18,628	17,723	16,683	15,603
		acfm	36,660	39,250	39,391	36,819	36,439	35,690	34,709
NO_X Emissions		lb/lb-mol	46.01	46.01	46.01	46.01	46.01	46.01	46.01
		ppmvd, 15% O_2	50	50	50	50	50	50	50
		ppmvw	20.45	18.74	19.44	20.19	20.95	21.52	22.12
		lb/hr	2.67	2.89	2.89	2.69	2.66	2.57	2.47
CO Emissions		lb/lb-mol	28.01	28.01	28.01	28.01	28.01	28.01	28.01
		ppmvd, 15% O_2	10,000	10,000	10,000	10,000	10,000	10,000	10,000
		ppmvw	4,090.15	3,748.96	3,888.80	4,038.15	4,190.84	4,304.13	4,424.95
		lb/hr	325.54	351.57	351.37	327.68	323.29	312.88	300.75
UHC Emissions		lb/lb-mol	18.37	18.37	18.37	18.37	18.37	18.37	18.37
		ppmvd, 15% O_2	7,700	7,700	7,700	7,700	7,700	7,700	7,700
		ppmvw	3,149.42	2,886.70	2,994.38	3,109.38	3,226.95	3,314.18	3,407.21
		lb/hr	164.41	177.56	177.46	165.49	163.28	158.02	151.89

NOTES

1. Footnotes 1 thru 4 of TABLE B-1Ab.

TABLE B-1Ad
Manufacturer's Operating and Emissions Data
Startup/Shutdown Step 2: Iginition-Idle
PTE - 100% Fuel Utilization at 100% Power Output

Vendor Data

Make:	Solar								
Model:	060-07802S4								
Rate	7,700 hp (ISO)								
Capacity:	6,800 hp (NEMA)								
Load:	10%								
Ambient	Temperature	°F		0.01	20.00	40.00	60.00	80.00	100.00
	Specific Humidity	$lb_{H2O}/lb_{Dry\ Air}$		0.0006	0.0014	0.0031	0.0066	0.0133	0.0253
Fuel	Lower Heating Value (LHV)	BTU/scf		939.2	939.2	939.2	939.2	939.2	939.2
Turbine	Net Output Power	hp		841	816	788	747	688	624
	Heat Input at LHV	MMBTU/hr		14.59	14.59	14.63	14.45	14.09	13.68
Exhaust	Temperature	°F		503	543	584	626	670	715
	Water Fraction	%		2.56%	2.78%	3.15%	3.79%	4.89%	6.76%
	O_2 Content	% (dry)		18.63%	18.54%	18.44%	18.33%	18.23%	18.10%
	Molecular Weight	lb/lb-mol		28.80	28.78	28.74	28.68	28.56	28.36
	Flow Rate	lb/hr		96,424	92,838	83,262	78,987	74,120	68,816
		acfm		39,250	39,391	36,819	36,439	35,690	34,709
Estimated	NO_X	ppmvd, 15% O_2		50	50	50	50	50	50
Emissions	CO	ppmvd, 15% O_2		10,000	10,000	10,000	10,000	10,000	10,000
	UHC	ppmvd, 15% O_2		7,700	7,700	7,700	7,700	7,700	7,700

TABLE B-1Ae
Manufacturer's Operating and Emissions Data
Startup/Shutdown Step 3: Loading/Thermal Stabilization
PTE - 100% Fuel Utilization at 100% Power Output

Parameters			Interpolated	Vendor Data					
Ambient	Temperature	°F	46.65	0.01	20.00	40.00	60.00	80.00	100.00
	Altitude	ft	0	0	0	0	0	0	0
	Pressure	psia	14.702	14.702	14.702	14.702	14.702	14.702	14.702
	Relative Humidity	%	60%	60%	60%	60%	60%	60%	60%
	Specific Humidity	$lb_{H2O}/lb_{Dry\ Air}$	0.0035	0.0006	0.0013	0.0028	0.0058	0.0124	0.0262
Fuel	Lower Heating Value (LHV)	BTU/scf	939.2	939.2	939.2	939.2	939.2	939.2	939.2
	Higher Heating Value (HHV)	BTU/scf	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6	1,043.6
Turbine	Net Output Power	hp	2,327	2,524	2,449	2,363	2,242	2,065	1,873
	Fuel Consumption	scf/hr	28,688	29,152	29,035	28,822	28,279	27,310	26,256
	Heat Input at LHV	MMBTU/hr	26.94	27.38	27.27	27.07	26.56	25.65	24.66
	Heat Input at HHV	MMBTU/hr	29.94	30.42	30.30	30.08	29.51	28.50	27.40
	Heat Rate at LHV	BTU/hp-hr	11,576	10,848	11,135	11,456	11,847	12,421	13,166
	Heat Rate at HHV	BTU/hp-hr	12,863	12,053	12,372	12,729	13,163	13,801	14,629
Exhaust	Temperature	°F	704	607	649	691	728	762	794
	Water Fraction	%, by vol	4.23%	3.45%	3.69%	4.06%	4.67%	5.71%	7.48%
	Non-Water Fraction	%, by vol	95.77%	96.55%	96.31%	95.94%	95.33%	94.29%	92.52%
	O_2 Content	%, by vol (dry)	17.52%	17.77%	17.66%	17.55%	17.47%	17.41%	17.35%
	Molecular Weight	lb/lb-mol	28.67	28.74	28.72	28.69	28.62	28.51	28.32
	Flow Rate	lb/hr	121,691	132,796	128,069	123,398	118,041	112,104	106,173
		scfm (1 atm, 68°F)	27,296	29,693	28,670	27,643	26,512	25,270	24,101
		acfm	60,139	59,982	60,194	60,237	59,630	58,463	57,218
NO_X Emissions		lb/lb-mol	46.01	46.01	46.01	46.01	46.01	46.01	46.01
		ppmvd, 15% O_2	60	60	60	60	60	60	60
		ppmvw	32.91	30.73	31.73	32.68	33.25	33.46	33.40
		lb/hr	6.43	6.53	6.51	6.47	6.31	6.05	5.76
CO Emissions		lb/lb-mol	28.01	28.01	28.01	28.01	28.01	28.01	28.01
		ppmvd, 15% O_2	9,000	9,000	9,000	9,000	9,000	9,000	9,000
		ppmvw	4,936.89	4,609.85	4,760.00	4,902.70	4,987.86	5,019.74	5,010.19
		lb/hr	586.91	596.62	594.54	590.64	576.22	552.86	526.12
UHC Emissions		lb/lb-mol	18.37	18.37	18.37	18.37	18.37	18.37	18.37
		ppmvd, 15% O_2	4,460	4,460	4,460	4,460	4,460	4,460	4,460
		ppmvw	2,446.50	2,284.44	2,358.84	2,429.56	2,471.76	2,487.56	2,482.83
		lb/hr	190.76	193.92	193.25	191.98	187.29	179.70	171.01

NOTES

1. Footnotes 1 thru 4 of TABLE B-1Ab.

TABLE B-1Ae
Manufacturer's Operating and Emissions Data
Startup/Shutdown Step 3: Loading/Thermal Stabilization
PTE - 100% Fuel Utilization at 100% Power Output

Vendor Data

Make:	Solar								
Model:	060-07802S4								
Rate Capacity:	7,700 hp (ISO)								
	6,800 hp (NEMA)								
Load:	29%								
Ambient	Temperature	°F		0.01	20.00	40.00	60.00	80.00	100.00
	Specific Humidity	$lb_{H2O}/lb_{Dry\ Air}$		0.0006	0.0014	0.0031	0.0066	0.0133	0.0253
Fuel	Lower Heating Value (LHV)	BTU/scf		939.2	939.2	939.2	939.2	939.2	939.2
Turbine	Net Output Power	hp		2,524	2,449	2,363	2,242	2,065	1,873
	Heat Input at LHV	MMBTU/hr		27.38	27.27	27.07	26.56	25.65	24.66
Exhaust	Temperature	°F		607	649	691	728	762	794
	Water Fraction	%		3.45%	3.69%	4.06%	4.67%	5.71%	7.48%
	O_2 Content	% (dry)		17.77%	17.66%	17.55%	17.47%	17.41%	17.35%
	Molecular Weight	lb/lb-mol		28.74	28.72	28.69	28.62	28.51	28.32
	Flow Rate	lb/hr		132,796	128,069	123,398	118,041	112,104	106,173
		acfm		59,982	60,194	60,237	59,630	58,463	57,218
Estimated Emissions	NO_X	ppmvd, 15% O_2		60	60	60	60	60	60
	CO	ppmvd, 15% O_2		9,000	9,000	9,000	9,000	9,000	9,000
	UHC	ppmvd, 15% O_2		4,460	4,460	4,460	4,460	4,460	4,460

TABLE B-1Af
Gas-Fired Turbines
Emission Estimates
Startup
PTE - 100% Fuel Utilization at 100% Power Output

Make	Solar				
Model	060-07802S4				
Fuel	Natural Gas				
Ambient Temperature	46.65 °F			0.01 °F	
Maximum Event Frequency		2 events/hr	416 events/yr		2 events/hr
Maximum Startup Time		18.00 min/hr	62.40 hrs/yr		18.00 min/hr
Fuel Consumption		7,292 scf/hr	1.52 MMscf/yr		7,384 scf/hr
		Average	Maximum		Maximum
NO_X	0.7764 lbs/event	1.5528 lb/hr	0.1615 tpy	0.7977 lbs/event	1.5955 lb/hr
CO	74.9676 lbs/event	149.9353 lb/hr	15.5933 tpy	77.2408 lbs/event	154.4816 lb/hr
SO_2	0.0521 lbs/event	0.1042 lb/hr	0.0108 tpy	0.0527 lbs/event	0.1055 lb/hr
$PM_{10/2.5}$	0.0245 lbs/event	0.0491 lb/hr	0.0051 tpy	0.0249 lbs/event	0.0497 lb/hr
$CO_{2\text{-}e}$	971 lbs/event	1,943 lb/hr	202 tpy	996 lbs/event	1,992 lb/hr
CO_2	438 lbs/event	875 lb/hr	91 tpy	443 lbs/event	886 lb/hr
N_2O	0.0008 lbs/event	0.0016 lb/hr	0.0002 tpy	0.0008 lbs/event	0.0017 lb/hr
TOC (Total)	27.2971 lbs/event	54.5943 lb/hr	5.6778 tpy	28.2703 lbs/event	56.5406 lb/hr
Methane	21.3414 lbs/event	42.6828 lb/hr	4.4390 tpy	22.1022 lbs/event	44.2045 lb/hr
Ethane	0.7445 lbs/event	1.4889 lb/hr	0.1548 tpy	0.7710 lbs/event	1.5420 lb/hr
VOC (Total)	5.2113 lbs/event	10.4225 lb/hr	1.0839 tpy	5.3971 lbs/event	10.7941 lb/hr
VOC (non-HAP)	2.6619 lbs/event	5.3238 lb/hr	0.5537 tpy	2.7568 lbs/event	5.5136 lb/hr
HAP (Total)	2.5494 lbs/event	5.0988 lb/hr	0.5303 tpy	2.6403 lbs/event	5.2805 lb/hr
Acetaldehyde	9.93E-02 lbs/event	0.1985 lb/hr	0.0206 tpy	1.03E-01 lbs/event	0.2056 lb/hr
Acrolein	1.59E-02 lbs/event	0.0318 lb/hr	0.0033 tpy	1.64E-02 lbs/event	0.0329 lb/hr
Benzene	2.98E-02 lbs/event	0.0596 lb/hr	0.0062 tpy	3.08E-02 lbs/event	0.0617 lb/hr
Biphenyl					
Butadiene (1,3-)	1.07E-03 lbs/event	0.0021 lb/hr	0.0002 tpy	1.11E-03 lbs/event	0.0022 lb/hr
Carbon Tetrachloride					
Chlorobenzene					
Chloroform					
Dichloropropene (1,3-)					
Ethylbenzene	7.94E-02 lbs/event	0.1588 lb/hr	0.0165 tpy	8.22E-02 lbs/event	0.1645 lb/hr
Ethylene Dibromide					
Formaldehyde	1.76E+00 lbs/event	3.5238 lb/hr	0.3665 tpy	1.82E+00 lbs/event	3.6494 lb/hr
Hexane (n-)					
Methanol					
Methylene Chloride					
Methylnaphthalene (2-)					
Naphthalene	3.23E-03 lbs/event	0.0065 lb/hr	0.0007 tpy	3.34E-03 lbs/event	0.0067 lb/hr
PAH	5.46E-03 lbs/event	0.0109 lb/hr	0.0011 tpy	5.65E-03 lbs/event	0.0113 lb/hr
Phenol					
Propylene Oxide	7.20E-02 lbs/event	0.1439 lb/hr	0.0150 tpy	7.45E-02 lbs/event	0.1491 lb/hr
Styrene					
Tetrachloroethane (1,1,2,2-)					
Toluene	3.23E-01 lbs/event	0.6452 lb/hr	0.0671 tpy	3.34E-01 lbs/event	0.6682 lb/hr
Trichloroethane (1,1,2-)					
Trimethylpentane (2,2,4-)					
Vinyl Chloride					
Xylenes	1.59E-01 lbs/event	0.3176 lb/hr	0.0330 tpy	1.64E-01 lbs/event	0.3290 lb/hr

NOTES

1. Emissions of NOx, CO, and UHC are estimated using information provided in TABLE B-1Ad and TABLE B-1Ae.

	46.65 °F		0.01 °F	
	Step 2	Step 3	Step 2	Step 3
Duration	3.00 min/event	6.00 min/event	3.00 min/event	6.00 min/event
NO_X	0.1337 lb/event	0.6427 lb/event	0.1444 lb/event	0.6534 lb/event
CO	16.2771 lb/event	58.6905 lb/event	17.5787 lb/event	59.6621 lb/event
UHC	8.2206 lb/event	19.0765 lb/event	8.8780 lb/event	19.3923 lb/event
Fuel	777 scf/event	2,869 scf/event	777 scf/event	2,915 scf/event

2. Footnotes 4 thru 8 of TABLE B-1Ac.
3. The frequency of startup events was provided by Technical Services.

TABLE B-1Ag
Gas-Fired Turbines
Emission Estimates
Shutdown
PTE - 100% Fuel Utilization at 100% Power Output

Make	Solar				
Model	060-07802S4				
Fuel	Natural Gas				
Ambient Temperature	46.65 °F			0.01 °F	
Maximum Event Frequency		2 events/hr	416 events/yr		2 events/hr
Maximum Startup Time		17.00 min/hr	58.93 hrs/yr		17.00 min/hr
Fuel Consumption		8,128 scf/hr	1.69 MMscf/yr		8,260 scf/hr
		Average	Maximum		Maximum
NO_X	0.9105 lbs/event	1.8210 lb/hr	0.1894 tpy	0.9256 lbs/event	1.8512 lb/hr
CO	83.1449 lbs/event	166.2898 lb/hr	17.2941 tpy	84.5213 lbs/event	169.0426 lb/hr
SO_2	0.0581 lbs/event	0.1161 lb/hr	0.0121 tpy	0.0590 lbs/event	0.1180 lb/hr
$PM_{10/2.5}$	0.0274 lbs/event	0.0547 lb/hr	0.0057 tpy	0.0278 lbs/event	0.0556 lb/hr
$CO_{2\text{-}e}$	1,016 lbs/event	2,033 lb/hr	211 tpy	1,033 lbs/event	2,066 lb/hr
CO_2	488 lbs/event	976 lb/hr	101 tpy	496 lbs/event	991 lb/hr
N_2O	0.0009 lbs/event	0.0018 lb/hr	0.0002 tpy	0.0009 lbs/event	0.0019 lb/hr
TOC (Total)	27.0250 lbs/event	54.0501 lb/hr	5.6212 tpy	27.4724 lbs/event	54.9448 lb/hr
Methane	21.1287 lbs/event	42.2573 lb/hr	4.3948 tpy	21.4784 lbs/event	42.9568 lb/hr
Ethane	0.7370 lbs/event	1.4741 lb/hr	0.1533 tpy	0.7492 lbs/event	1.4985 lb/hr
VOC (Total)	5.1593 lbs/event	10.3186 lb/hr	1.0731 tpy	5.2447 lbs/event	10.4895 lb/hr
VOC (non-HAP)	2.6354 lbs/event	5.2707 lb/hr	0.5482 tpy	2.6790 lbs/event	5.3580 lb/hr
HAP (Total)	2.5240 lbs/event	5.0479 lb/hr	0.5250 tpy	2.5657 lbs/event	5.1315 lb/hr
Acetaldehyde	9.83E-02 lbs/event	0.1965 lb/hr	0.0204 tpy	9.99E-02 lbs/event	0.1998 lb/hr
Acrolein	1.57E-02 lbs/event	0.0314 lb/hr	0.0033 tpy	1.60E-02 lbs/event	0.0320 lb/hr
Benzene	2.95E-02 lbs/event	0.0590 lb/hr	0.0061 tpy	3.00E-02 lbs/event	0.0599 lb/hr
Biphenyl					
Butadiene (1,3-)	1.06E-03 lbs/event	0.0021 lb/hr	0.0002 tpy	1.07E-03 lbs/event	0.0021 lb/hr
Carbon Tetrachloride					
Chlorobenzene					
Chloroform					
Dichloropropene (1,3-)					
Ethylbenzene	7.86E-02 lbs/event	0.1572 lb/hr	0.0164 tpy	7.99E-02 lbs/event	0.1598 lb/hr
Ethylene Dibromide					
Formaldehyde	1.74E+00 lbs/event	3.4887 lb/hr	0.3628 tpy	1.77E+00 lbs/event	3.5464 lb/hr
Hexane (n-)					
Methanol					
Methylene Chloride					
Methylnaphthalene (2-)					
Naphthalene	3.19E-03 lbs/event	0.0064 lb/hr	0.0007 tpy	3.25E-03 lbs/event	0.0065 lb/hr
PAH	5.41E-03 lbs/event	0.0108 lb/hr	0.0011 tpy	5.49E-03 lbs/event	0.0110 lb/hr
Phenol					
Propylene Oxide	7.12E-02 lbs/event	0.1425 lb/hr	0.0148 tpy	7.24E-02 lbs/event	0.1449 lb/hr
Styrene					
Tetrachloroethane (1,1,2,2-)					
Toluene	3.19E-01 lbs/event	0.6388 lb/hr	0.0664 tpy	3.25E-01 lbs/event	0.6493 lb/hr
Trichloroethane (1,1,2-)					
Trimethylpentane (2,2,4-)					
Vinyl Chloride					
Xylenes	1.57E-01 lbs/event	0.3145 lb/hr	0.0327 tpy	1.60E-01 lbs/event	0.3197 lb/hr

NOTES

1. Emissions of NOx, CO, and UHC are estimated using information provided in TABLE B-1Ad and TABLE B-1Ae.

	46.65 °F		0.01 °F	
	Step 2	Step 3	Step 2	Step 3
Duration	0.00 min/event	8.50 min/event	0.00 min/event	8.50 min/event
NO_X	0.0000 lb/event	0.9105 lb/event	0.0000 lb/event	0.9256 lb/event
CO	0.0000 lb/event	83.1449 lb/event	0.0000 lb/event	84.5213 lb/event
UHC	0.0000 lb/event	27.0250 lb/event	0.0000 lb/event	27.4724 lb/event
Fuel	0 scf/event	4,064 scf/event	0 scf/event	4,130 scf/event

2. Footnotes 4 thru 8 of TABLE B-1Ac.
3. The frequency of startup events was provided by Technical Services.

TABLE B-1Ah
Gas-Fired Turbines
Emission Estimates
Low Temperatures
PTE - 100% Fuel Utilization at 100% Power Output

Make	Solar					
Model	060-07802S4					
Normal Operating Load	100%					
Fuel	Natural Gas					
Fuel Higher Heating Value (HHV)	1,020 BTU/scf			1,020 BTU/scf		
Ambient Temperature	-20.00 °F			-20.00 °F		
Power Output	8,664 bhp (mech.)			8,664 bhp (mech.)		
	6,461 kW (elec.)			6,461 kW (elec.)		
Heat Rate at HHV	8,646 BTU/hp-hr			8,646 BTU/hp-hr		
Operating Hours	12 hrs/yr			0 hrs/yr		
Fuel Consumption	73,444 scfh			73,444 scfh		
	0.881 MMscf/yr			0.000 MMscf/yr		
Heat Input at HHV	74.91 MMBTU/hr	0°F ≥ T > -20°F		74.91 MMBTU/hr	T ≤ -20°F	
	899 MMBTU/yr	Hourly	Annual	0 MMBTU/yr	Hourly	Annual
NO_X	154.71 lb/MMscf	11.3622 lb/hr	0.0682 tpy	442.02 lb/MMscf	32.4635 lb/hr	0.0000 tpy
CO	224.24 lb/MMscf	16.4693 lb/hr	0.0988 tpy	336.37 lb/MMscf	24.7040 lb/hr	0.0000 tpy
SO_2	14.29 lb/MMscf	1.0492 lb/hr	0.0063 tpy	14.29 lb/MMscf	1.0492 lb/hr	0.0000 tpy
$PM_{10/2.5}$	6.73 lb/MMscf	0.4944 lb/hr	0.0030 tpy	6.73 lb/MMscf	0.4944 lb/hr	0.0000 tpy
$CO_{2\text{-e}}$	121,522 lb/MMscf	8,925 lb/hr	54 tpy	122,241 lb/MMscf	8,978 lb/hr	0 tpy
CO_2	120,017 lb/MMscf	8,815 lb/hr	53 tpy	120,017 lb/MMscf	8,815 lb/hr	0 tpy
N_2O	0.23 lb/MMscf	0.0166 lb/hr	0.0001 tpy	0.23 lb/MMscf	0.0166 lb/hr	0.0000 tpy
TOC (Total)	73.54 lb/MMscf	5.4011 lb/hr	0.0324 tpy	110.31 lb/MMscf	8.1017 lb/hr	0.0000 tpy
Methane	57.50 lb/MMscf	4.2227 lb/hr	0.0253 tpy	86.24 lb/MMscf	6.3340 lb/hr	0.0000 tpy
Ethane	2.01 lb/MMscf	0.1473 lb/hr	0.0009 tpy	3.01 lb/MMscf	0.2210 lb/hr	0.0000 tpy
VOC (Total)	14.04 lb/MMscf	1.0311 lb/hr	0.0062 tpy	21.06 lb/MMscf	1.5467 lb/hr	0.0000 tpy
VOC (non-HAP)	7.17 lb/MMscf	0.5267 lb/hr	0.0032 tpy	10.76 lb/MMscf	0.7900 lb/hr	0.0000 tpy
HAP (Total)	6.87 lb/MMscf	0.5044 lb/hr	0.0030 tpy	10.30 lb/MMscf	0.7566 lb/hr	0.0000 tpy
Acetaldehyde	2.67E-01 lb/MMscf	0.0196 lb/hr	0.0001 tpy	4.01E-01 lb/MMscf	0.0295 lb/hr	0.0000 tpy
Acrolein	4.28E-02 lb/MMscf	0.0031 lb/hr	0.0000 tpy	6.42E-02 lb/MMscf	0.0047 lb/hr	0.0000 tpy
Benzene	8.02E-02 lb/MMscf	0.0059 lb/hr	0.0000 tpy	1.20E-01 lb/MMscf	0.0088 lb/hr	0.0000 tpy
Biphenyl						
Butadiene (1,3-)	2.87E-03 lb/MMscf	0.0002 lb/hr	0.0000 tpy	4.31E-03 lb/MMscf	0.0003 lb/hr	0.0000 tpy
Carbon Tetrachloride						
Chlorobenzene						
Chloroform						
Dichloropropene (1,3-)						
Ethylbenzene	2.14E-01 lb/MMscf	0.0157 lb/hr	0.0001 tpy	3.21E-01 lb/MMscf	0.0236 lb/hr	0.0000 tpy
Ethylene Dibromide						
Formaldehyde	4.75E+00 lb/MMscf	0.3486 lb/hr	0.0021 tpy	7.12E+00 lb/MMscf	0.5229 lb/hr	0.0000 tpy
Hexane (n-)						
Methanol						
Methylene Chloride						
Methylnaphthalene (2-)						
Naphthalene	8.69E-03 lb/MMscf	0.0006 lb/hr	0.0000 tpy	1.30E-02 lb/MMscf	0.0010 lb/hr	0.0000 tpy
PAH	1.47E-02 lb/MMscf	0.0011 lb/hr	0.0000 tpy	2.21E-02 lb/MMscf	0.0016 lb/hr	0.0000 tpy
Phenol						
Propylene Oxide	1.94E-01 lb/MMscf	0.0142 lb/hr	0.0001 tpy	2.91E-01 lb/MMscf	0.0214 lb/hr	0.0000 tpy
Styrene						
Tetrachloroethane (1,1,2,2-)						
Toluene	8.69E-01 lb/MMscf	0.0638 lb/hr	0.0004 tpy	1.30E+00 lb/MMscf	0.0957 lb/hr	0.0000 tpy
Trichloroethane (1,1,2-)						
Trimethylpentane (2,2,4-)						
Vinyl Chloride						
Xylenes	4.28E-01 lb/MMscf	0.0314 lb/hr	0.0002 tpy	6.42E-01 lb/MMscf	0.0471 lb/hr	0.0000 tpy

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Operating hours for low ambient temperatures best on best fit of available data (see TABLE B-1Aa).
3. Manufacturer provided data on: power output, heat rate, along with NOx, CO, and UHC (or TOC) emissions.
4. Footnotes 4 thru 8 of TABLE B-1Ac.

TABLE B-1Aj
Gas-Fired Turbines
Maximum Emission Estimates
Normal Operations, Startup, Shutdown, and Low Temperature Operations
PTE - 100% Fuel Utilization at 100% Power Output

Make		Solar																	
Model		060-07802S4																	
Normal Operating Load		100%																	
Operations		Normal			Startup			Shutdown			Startup/Shutdown w/ Normal			Low Temperatures			Combined Operations		
Maximum Annual Combined Event Frequency		8,760 hrs/yr			62 hrs/yr			59 hrs/yr			8,760 hrs/yr			12 hrs/yr			8,760 hrs/yr		
Pollutant	Control Efficiency	Hourly		Maximum	Hourly		Maximum	Hourly		Maximum	Hourly		Maximum	Hourly		Maximum	Hourly		Maximum
		Average	Maximum	Annual	Average	Maximum	Annual	Average	Maximum	Annual	Average	Maximum	Annual	Average	Maximum	Annual	Average	Maximum	Annual
NO_X		2.2288 lb/hr	2.3799 lb/hr	9.7621 tpy	1.5528 lb/hr	1.5955 lb/hr	0.1615 tpy	1.8210 lb/hr	1.8512 lb/hr	0.1894 tpy	2.2780 lb/hr	4.4382 lb/hr	9.9777 tpy	11.3622 lb/hr	32.4635 lb/hr	0.0682 tpy	2.2905 lb/hr	32.4635 lb/hr	10.0325 tpy
CO	95.00% by weight	0.1884 lb/hr	0.2012 lb/hr	0.8254 tpy	149.9353 lb/hr	154.4816 lb/hr	15.5933 tpy	8.3145 lb/hr	8.4521 lb/hr	0.8647 tpy	3.9434 lb/hr	163.0176 lb/hr	17.2720 tpy	0.8235 lb/hr	1.2352 lb/hr	0.0049 tpy	3.9442 lb/hr	163.0176 lb/hr	17.2758 tpy
SO_2		0.9658 lb/hr	1.0266 lb/hr	4.2302 tpy	0.1042 lb/hr	0.1055 lb/hr	0.0108 tpy	0.1161 lb/hr	0.1180 lb/hr	0.0121 tpy	0.9658 lb/hr	1.0266 lb/hr	4.2302 tpy	1.0492 lb/hr	1.0492 lb/hr	0.0063 tpy	0.9659 lb/hr	1.0492 lb/hr	4.2307 tpy
$PM_{10/2.5}$		0.4551 lb/hr	0.4838 lb/hr	1.9934 tpy	0.0491 lb/hr	0.0497 lb/hr	0.0051 tpy	0.0547 lb/hr	0.0556 lb/hr	0.0057 tpy	0.4551 lb/hr	0.4838 lb/hr	1.9934 tpy	0.4944 lb/hr	0.4944 lb/hr	0.0030 tpy	0.4552 lb/hr	0.4944 lb/hr	1.9937 tpy
$CO_{2\text{-}e}$		8,172 lb/hr	8,687 lb/hr	35,795 tpy	1,943 lb/hr	1,992 lb/hr	202 tpy	2,281 lb/hr	2,318 lb/hr	237 tpy	8,172 lb/hr	8,687 lb/hr	35,795 tpy	8,950 lb/hr	9,015 lb/hr	54 tpy	8,173 lb/hr	11,057 lb/hr	35,800 tpy
CO_2		8,120 lb/hr	8,631 lb/hr	35,564 tpy	875 lb/hr	886 lb/hr	91 tpy	1,224 lb/hr	1,244 lb/hr	127 tpy	8,120 lb/hr	8,631 lb/hr	35,564 tpy	8,839 lb/hr	8,851 lb/hr	53 tpy	8,121 lb/hr	8,851 lb/hr	35,568 tpy
N_2O		0.0153 lb/hr	0.0163 lb/hr	0.0670 tpy	0.0016 lb/hr	0.0017 lb/hr	0.0002 tpy	0.0018 lb/hr	0.0019 lb/hr	0.0002 tpy	0.0153 lb/hr	0.0163 lb/hr	0.0670 tpy	0.0166 lb/hr	0.0166 lb/hr	0.0001 tpy	0.0153 lb/hr	0.0166 lb/hr	0.0670 tpy
TOC (Total)	10.91% by weight	2.2024 lb/hr	2.3517 lb/hr	9.6465 tpy	54.5943 lb/hr	56.5406 lb/hr	5.6778 tpy	48.1537 lb/hr	48.9508 lb/hr	5.0080 tpy	4.6116 lb/hr	106.4713 lb/hr	20.1987 tpy	4.8119 lb/hr	7.2179 lb/hr	0.0289 tpy	4.6152 lb/hr	106.4713 lb/hr	20.2144 tpy
Methane	0.00% by weight	1.9327 lb/hr	2.0637 lb/hr	8.4653 tpy	42.6828 lb/hr	44.2045 lb/hr	4.4390 tpy	42.2573 lb/hr	42.9568 lb/hr	4.3948 tpy	3.9228 lb/hr	88.0212 lb/hr	17.1819 tpy	4.2227 lb/hr	6.3340 lb/hr	0.0253 tpy	3.9259 lb/hr	88.0212 lb/hr	17.1956 tpy
Ethane	50.00% by weight	0.0337 lb/hr	0.0360 lb/hr	0.1477 tpy	1.4889 lb/hr	1.5420 lb/hr	0.1548 tpy	0.7370 lb/hr	0.7492 lb/hr	0.0767 tpy	0.0861 lb/hr	2.3063 lb/hr	0.3771 tpy	0.0737 lb/hr	0.1105 lb/hr	0.0004 tpy	0.0862 lb/hr	2.3063 lb/hr	0.3773 tpy
VOC (Total)	50.00% by weight	0.2360 lb/hr	0.2520 lb/hr	1.0336 tpy	10.4225 lb/hr	10.7941 lb/hr	1.0839 tpy	5.1593 lb/hr	5.2447 lb/hr	0.5366 tpy	0.6027 lb/hr	16.1438 lb/hr	2.6398 tpy	0.5156 lb/hr	0.7733 lb/hr	0.0031 tpy	0.6031 lb/hr	16.1438 lb/hr	2.6414 tpy
VOC (non-HAP)	19.10% by weight	0.1950 lb/hr	0.2083 lb/hr	0.8542 tpy	5.3238 lb/hr	5.5136 lb/hr	0.5537 tpy	4.2642 lb/hr	4.3348 lb/hr	0.4435 tpy	0.4200 lb/hr	9.9352 lb/hr	1.8396 tpy	0.4261 lb/hr	0.6392 lb/hr	0.0026 tpy	0.4203 lb/hr	9.9352 lb/hr	1.8410 tpy
HAP (Total)	8.23E-01 by weight	0.0409 lb/hr	0.0437 lb/hr	0.1793 tpy	5.0988 lb/hr	5.2805 lb/hr	0.5303 tpy	0.8951 lb/hr	0.9099 lb/hr	0.0931 tpy	0.1827 lb/hr	6.2087 lb/hr	0.8002 tpy	0.0894 lb/hr	0.1342 lb/hr	0.0005 tpy	0.1828 lb/hr	6.2087 lb/hr	0.8005 tpy
Acetaldehyde	80.00% by weight	1.80E-03 lb/hr	1.92E-03 lb/hr	7.87E-03 tpy	1.99E-01 lb/hr	2.06E-01 lb/hr	2.06E-02 tpy	3.93E-02 lb/hr	4.00E-02 lb/hr	4.09E-03 tpy	7.42E-03 lb/hr	2.46E-01 lb/hr	3.25E-02 tpy	3.93E-03 lb/hr	5.89E-03 lb/hr	2.36E-05 tpy	7.42E-03 lb/hr	2.46E-01 lb/hr	3.25E-02 tpy
Acrolein	50.00% by weight	7.19E-04 lb/hr	7.68E-04 lb/hr	3.15E-03 tpy	3.18E-02 lb/hr	3.29E-02 lb/hr	3.30E-03 tpy	1.57E-02 lb/hr	1.60E-02 lb/hr	1.64E-03 tpy	1.84E-03 lb/hr	4.92E-02 lb/hr	8.04E-03 tpy	1.57E-03 lb/hr	2.36E-03 lb/hr	9.43E-06 tpy	1.84E-03 lb/hr	4.92E-02 lb/hr	8.05E-03 tpy
Benzene	50.00% by weight	1.35E-03 lb/hr	1.44E-03 lb/hr	5.91E-03 tpy	5.96E-02 lb/hr	6.17E-02 lb/hr	6.19E-03 tpy	2.95E-02 lb/hr	3.00E-02 lb/hr	3.07E-03 tpy	3.44E-03 lb/hr	9.23E-02 lb/hr	1.51E-02 tpy	2.95E-03 lb/hr	4.42E-03 lb/hr	1.77E-05 tpy	3.45E-03 lb/hr	9.23E-02 lb/hr	1.51E-02 tpy
Biphenyl	0.00% by weight																		
Butadiene (1,3-)	50.00% by weight	4.83E-05 lb/hr	5.16E-05 lb/hr	2.12E-04 tpy	2.13E-03 lb/hr	2.21E-03 lb/hr	2.22E-04 tpy	1.06E-03 lb/hr	1.07E-03 lb/hr	1.10E-04 tpy	1.23E-04 lb/hr	3.31E-03 lb/hr	5.41E-04 tpy	1.06E-04 lb/hr	1.58E-04 lb/hr	6.33E-07 tpy	1.23E-04 lb/hr	3.31E-03 lb/hr	5.41E-04 tpy
Carbon Tetrachloride	50.00% by weight																		
Chlorobenzene	50.00% by weight																		
Chloroform	50.00% by weight																		
Dichloropropene (1,3-)	50.00% by weight																		
Ethylbenzene	50.00% by weight	3.60E-03 lb/hr	3.84E-03 lb/hr	1.57E-02 tpy	1.59E-01 lb/hr	1.64E-01 lb/hr	1.65E-02 tpy	7.86E-02 lb/hr	7.99E-02 lb/hr	8.18E-03 tpy	9.18E-03 lb/hr	2.46E-01 lb/hr	4.02E-02 tpy	7.86E-03 lb/hr	1.18E-02 lb/hr	4.71E-05 tpy	9.19E-03 lb/hr	2.46E-01 lb/hr	4.03E-02 tpy
Ethylene Dibromide	50.00% by weight																		
Formaldehyde	95.00% by weight	7.98E-03 lb/hr	8.52E-03 lb/hr	3.49E-02 tpy	3.52E+00 lb/hr	3.65E+00 lb/hr	3.66E-01 tpy	1.74E-01 lb/hr	1.77E-01 lb/hr	1.81E-02 tpy	9.57E-02 lb/hr	3.83E+00 lb/hr	4.19E-01 tpy	1.74E-02 lb/hr	2.61E-02 lb/hr	1.05E-04 tpy	9.57E-02 lb/hr	3.83E+00 lb/hr	4.19E-01 tpy
Hexane (n-)	50.00% by weight																		
Methanol	95.00% by weight																		
Methylene Chloride	50.00% by weight																		
Methylnaphthalene (2-)	50.00% by weight																		
Naphthalene	50.00% by weight	1.46E-04 lb/hr	1.56E-04 lb/hr	6.40E-04 tpy	6.45E-03 lb/hr	6.68E-03 lb/hr	6.71E-04 tpy	3.19E-03 lb/hr	3.25E-03 lb/hr	3.32E-04 tpy	3.73E-04 lb/hr	9.99E-03 lb/hr	1.63E-03 tpy	3.19E-04 lb/hr	4.79E-04 lb/hr	1.91E-06 tpy	3.73E-04 lb/hr	9.99E-03 lb/hr	1.64E-03 tpy
PAH	50.00% by weight	2.47E-04 lb/hr	2.64E-04 lb/hr	1.08E-03 tpy	1.09E-02 lb/hr	1.13E-02 lb/hr	1.14E-03 tpy	5.41E-03 lb/hr	5.49E-03 lb/hr	5.62E-04 tpy	6.31E-04 lb/hr	1.69E-02 lb/hr	2.77E-03 tpy	5.40E-04 lb/hr	8.10E-04 lb/hr	3.24E-06 tpy	6.32E-04 lb/hr	1.69E-02 lb/hr	2.77E-03 tpy
Phenol	50.00% by weight																		
Propylene Oxide	50.00% by weight	3.26E-03 lb/hr	3.48E-03 lb/hr	1.43E-02 tpy	1.44E-01 lb/hr	1.49E-01 lb/hr	1.50E-02 tpy	7.12E-02 lb/hr	7.24E-02 lb/hr	7.41E-03 tpy	8.32E-03 lb/hr	2.23E-01 lb/hr	3.65E-02 tpy	7.12E-03 lb/hr	1.07E-02 lb/hr	4.27E-05 tpy	8.33E-03 lb/hr	2.23E-01 lb/hr	3.65E-02 tpy
Styrene	0.00% by weight																		
Tetrachloroethane (1,1,2,2-)	50.00% by weight																		
Toluene	50.00% by weight	1.46E-02 lb/hr	1.56E-02 lb/hr	6.40E-02 tpy	6.45E-01 lb/hr	6.68E-01 lb/hr	6.71E-02 tpy	3.19E-01 lb/hr	3.25E-01 lb/hr	3.32E-02 tpy	3.73E-02 lb/hr	9.99E-01 lb/hr	1.63E-01 tpy	3.19E-02 lb/hr	4.79E-02 lb/hr	1.91E-04 tpy	3.73E-02 lb/hr	9.99E-01 lb/hr	1.64E-01 tpy
Trichloroethane (1,1,2-)	50.00% by weight																		
Trimethylpentane (2,2,4-)	50.00% by weight																		
Vinyl Chloride	0.00% by weight																		
Xylenes	50.00% by weight	7.19E-03 lb/hr	7.68E-03 lb/hr	3.15E-02 tpy	3.18E-01 lb/hr	3.29E-01 lb/hr	3.30E-02 tpy	1.57E-01 lb/hr	1.60E-01 lb/hr	1.64E-02 tpy	1.84E-02 lb/hr	4.92E-01 lb/hr	8.04E-02 tpy	1.57E-02 lb/hr	2.36E-02 lb/hr	9.43E-05 tpy	1.84E-02 lb/hr	4.92E-01 lb/hr	8.05E-02 tpy

NOTES

1. See TABLE B-1Ai.
2. It's assumed that oxidation catalyst will be ineffective during startup events.
3. $CO2 = CO2_{uncontrolled} + CE_{CO\text{-}control\ efficiency} * CO_{uncontrolled} * (MW_{CO2}/MW_{CO}) = CO2_{uncontrolled} + CE_{CO\text{-}control\ efficiency} * CO_{uncontrolled} * (44.0095/28.0101)$.

TABLE C-1A
4-Stroke Lean-Burn Reciprocating Engines
Hourly and Annual Emission Estimates
Uncontrolled

Type		4slb				
Service		Emergency				
JJJJ Relevant Date		Manufactured: On or After 01/01/2009				
ZZZZ Status		New RICE at Area HAP Source				
Make		Waukesha				
Model		VGF24GL				
Fuel		Natural Gas				
Fuel Higher Heating Value (HHV)		1,020 BTU/scf			1,020 BTU/scf	
Ambient Temperature		80 °F			80 °F	
Power Output		585 bhp (mech.)			585 bhp (mech.)	
		405 kW (elec.)			405 kW (elec.)	
Heat Rate at HHV		7,911 BTU/hp-hr			7,911 BTU/hp-hr	
Operating Hours		300 hrs/yr				
Fuel Consumption		4,537 scfh			4,537 scfh	
		1.361 MMscf/yr				
Heat Input at HHV		4.63 MMBTU/hr			4.63 MMBTU/hr	
		1,388 MMBTU/yr	Uncontrolled			Uncontrolled
Pollutant	Control Efficiency	Uncontrolled	Average Hourly	Maximum Annual	Uncontrolled	Maximum Hourly
NO_X		568.49 lb/MMscf	2.5794 lb/hr	0.3869 tpy	568.49 lb/MMscf	2.5794 lb/hr
CO		369.52 lb/MMscf	1.6766 lb/hr	0.2515 tpy	369.52 lb/MMscf	1.6766 lb/hr
SO_2		14.29 lb/MMscf	0.0648 lb/hr	0.0097 tpy	14.29 lb/MMscf	0.0648 lb/hr
$PM_{10/2.5}$		10.19 lb/MMscf	0.0462 lb/hr	0.0069 tpy	10.19 lb/MMscf	0.0462 lb/hr
$CO_{2\text{-}e}$		152,049 lb/MMscf	690 lb/hr	103 tpy	152,049 lb/MMscf	690 lb/hr
CO_2		120,017 lb/MMscf	545 lb/hr	82 tpy	120,017 lb/MMscf	545 lb/hr
N_2O		0.23 lb/MMscf	0.0010 lb/hr	0.0002 tpy	0.23 lb/MMscf	0.0010 lb/hr
TOC (Total)		1,503.58 lb/MMscf	6.8221 lb/hr	1.0233 tpy	1,503.58 lb/MMscf	6.8221 lb/hr
Methane		1,278.55 lb/MMscf	5.8011 lb/hr	0.8702 tpy	1,278.55 lb/MMscf	5.8011 lb/hr
Ethane		102.90 lb/MMscf	0.4669 lb/hr	0.0700 tpy	102.90 lb/MMscf	0.4669 lb/hr
VOC (Total)		122.13 lb/MMscf	0.5541 lb/hr	0.0831 tpy	122.13 lb/MMscf	0.5541 lb/hr
VOC (non-HAP)		48.29 lb/MMscf	0.2191 lb/hr	0.0329 tpy	48.29 lb/MMscf	0.2191 lb/hr
HAP (Total)		73.84 lb/MMscf	0.3351 lb/hr	0.0503 tpy	73.84 lb/MMscf	0.3351 lb/hr
Acetaldehyde		8.55E+00 lb/MMscf	3.88E-02 lb/hr	5.82E-03 tpy	8.55E+00 lb/MMscf	3.88E-02 lb/hr
Acrolein		5.26E+00 lb/MMscf	2.39E-02 lb/hr	3.58E-03 tpy	5.26E+00 lb/MMscf	2.39E-02 lb/hr
Benzene		4.50E-01 lb/MMscf	2.04E-03 lb/hr	3.06E-04 tpy	4.50E-01 lb/MMscf	2.04E-03 lb/hr
Biphenyl		2.17E-01 lb/MMscf	9.84E-04 lb/hr	1.48E-04 tpy	2.17E-01 lb/MMscf	9.84E-04 lb/hr
Butadiene (1,3-)		2.73E-01 lb/MMscf	1.24E-03 lb/hr	1.86E-04 tpy	2.73E-01 lb/MMscf	1.24E-03 lb/hr
Carbon Tetrachloride		3.75E-02 lb/MMscf	1.70E-04 lb/hr	2.55E-05 tpy	3.75E-02 lb/MMscf	1.70E-04 lb/hr
Chlorobenzene		3.11E-02 lb/MMscf	1.41E-04 lb/hr	2.12E-05 tpy	3.11E-02 lb/MMscf	1.41E-04 lb/hr
Chloroform		2.92E-02 lb/MMscf	1.32E-04 lb/hr	1.98E-05 tpy	2.92E-02 lb/MMscf	1.32E-04 lb/hr
Dichloropropene (1,3-)		2.70E-02 lb/MMscf	1.23E-04 lb/hr	1.84E-05 tpy	2.70E-02 lb/MMscf	1.23E-04 lb/hr
Ethylbenzene		4.06E-02 lb/MMscf	1.84E-04 lb/hr	2.76E-05 tpy	4.06E-02 lb/MMscf	1.84E-04 lb/hr
Ethylene Dibromide		4.53E-02 lb/MMscf	2.06E-04 lb/hr	3.08E-05 tpy	4.53E-02 lb/MMscf	2.06E-04 lb/hr
Formaldehyde		5.40E+01 lb/MMscf	2.45E-01 lb/hr	3.68E-02 tpy	5.40E+01 lb/MMscf	2.45E-01 lb/hr
Hexane (n-)		1.14E+00 lb/MMscf	5.15E-03 lb/hr	7.73E-04 tpy	1.14E+00 lb/MMscf	5.15E-03 lb/hr
Methanol		2.56E+00 lb/MMscf	1.16E-02 lb/hr	1.74E-03 tpy	2.56E+00 lb/MMscf	1.16E-02 lb/hr
Methylene Chloride		2.05E-02 lb/MMscf	9.28E-05 lb/hr	1.39E-05 tpy	2.05E-02 lb/MMscf	9.28E-05 lb/hr
Methylnaphthalene (2-)		3.40E-02 lb/MMscf	1.54E-04 lb/hr	2.31E-05 tpy	3.40E-02 lb/MMscf	1.54E-04 lb/hr
Naphthalene		7.61E-02 lb/MMscf	3.45E-04 lb/hr	5.18E-05 tpy	7.61E-02 lb/MMscf	3.45E-04 lb/hr
PAH		2.75E-02 lb/MMscf	1.25E-04 lb/hr	1.87E-05 tpy	2.75E-02 lb/MMscf	1.25E-04 lb/hr
Phenol		2.45E-02 lb/MMscf	1.11E-04 lb/hr	1.67E-05 tpy	2.45E-02 lb/MMscf	1.11E-04 lb/hr
Propylene Oxide						
Styrene		2.41E-02 lb/MMscf	1.10E-04 lb/hr	1.64E-05 tpy	2.41E-02 lb/MMscf	1.10E-04 lb/hr
Tetrachloroethane (1,1,2,2-)		4.35E-02 lb/MMscf	1.97E-04 lb/hr	2.96E-05 tpy	4.35E-02 lb/MMscf	1.97E-04 lb/hr
Toluene		4.17E-01 lb/MMscf	1.89E-03 lb/hr	2.84E-04 tpy	4.17E-01 lb/MMscf	1.89E-03 lb/hr
Trichloroethane (1,1,2-)		3.25E-02 lb/MMscf	1.48E-04 lb/hr	2.21E-05 tpy	3.25E-02 lb/MMscf	1.48E-04 lb/hr
Trimethylpentane (2,2,4-)		2.56E-01 lb/MMscf	1.16E-03 lb/hr	1.74E-04 tpy	2.56E-01 lb/MMscf	1.16E-03 lb/hr
Vinyl Chloride		1.52E-02 lb/MMscf	6.91E-05 lb/hr	1.04E-05 tpy	1.52E-02 lb/MMscf	6.91E-05 lb/hr
Xylenes		1.88E-01 lb/MMscf	8.54E-04 lb/hr	1.28E-04 tpy	1.88E-01 lb/MMscf	8.54E-04 lb/hr

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Maximum hourly emissions based on 100% of rated capacity.
3. Vendor provided data on power output and heat rate.
4. SO2 emission factor based on AP-42, Section 3.2 (Revised 7/00), Table 3.2-1 using Tariff (5 gr/100 scf).
5. PM10/2.5 emission factor based on AP-42, Section 3.2 (Revised 7/00), Table 3.2-2.
6. CO2 and N2O emission factors based on 40 CFR 98, Subpart C, Table C-1 and 40 CFR 98, Subpart C, Table C-2, respectively.
7. NOX, CO, and Formaldehyde emission factors based on Vendor Data.
8. TOC (Total) and TOC specie emissions are estimated based on scaling of AP-42 using vendor Formaldehyde data.
   Emission factors based on: $EF_i = [EF_{Formaldehyde}/EF_{Formaldehyde\text{-}AP42}]\ (EF_{i\text{-}AP42})$

TABLE D-1A
Natural Gas Combustion
Hourly and Annual Emission Estimates
Uncontrolled

Application		Process Heater				
Combustion Process		Conventional				
Add-on Controls		None				
Package (Make: Model)		Hanover: N/A				
Burner (Make: Model)		Unknown: Unknown				
Fuel		Natural Gas				
Fuel Higher Heating Value (HHV)		1,020 BTU/scf			1,020 BTU/scf	
Heat Output at HHV		7.000 MMBTU/hr			7.350 MMBTU/hr	
Thermal Efficiency		74%			74%	
Operating Hours		8,760 hrs/yr				
Fuel Consumption		9,337 scfh			9,804 scfh	
		81.793 MMscf/yr				
Heat Input at HHV		9.524 MMBTU/hr			10.000 MMBTU/hr	
		83,429 MMBTU/yr	Uncontrolled			Uncontrolled
Pollutant	Control Efficiency	Uncontrolled	Average Hourly	Maximum Annual	Uncontrolled	Maximum Hourly
NO_X		98.43 lb/MMscf	0.9191 lb/hr	4.0255 tpy	98.43 lb/MMscf	0.9650 lb/hr
CO		150.00 lb/MMscf	1.4006 lb/hr	6.1345 tpy	150.00 lb/MMscf	1.4706 lb/hr
SO_2		14.29 lb/MMscf	0.1334 lb/hr	0.5842 tpy	14.29 lb/MMscf	0.1401 lb/hr
$PM_{10/2.5}$		7.60 lb/MMscf	0.0710 lb/hr	0.3108 tpy	7.60 lb/MMscf	0.0745 lb/hr
CO_{2-e}		120,338.86 lb/MMscf	1,123.6122 lb/hr	4,921.4213 tpy	120,338.86 lb/MMscf	1,179.7928 lb/hr
CO_2		120,017.45 lb/MMscf	1,120.6111 lb/hr	4,908.2768 tpy	120,017.45 lb/MMscf	1,176.6417 lb/hr
N_2O		0.23 lb/MMscf	0.0021 lb/hr	0.0093 tpy	0.23 lb/MMscf	0.0022 lb/hr
TOC (Total)		60.00 lb/MMscf	0.5602 lb/hr	2.4538 tpy	60.00 lb/MMscf	0.5882 lb/hr
Methane		10.16 lb/MMscf	0.0949 lb/hr	0.4155 tpy	10.16 lb/MMscf	0.0996 lb/hr
Ethane		13.69 lb/MMscf	0.1279 lb/hr	0.5600 tpy	13.69 lb/MMscf	0.1343 lb/hr
VOC (Total)		36.15 lb/MMscf	0.3375 lb/hr	1.4782 tpy	36.15 lb/MMscf	0.3544 lb/hr
VOC (non-HAP)		27.83 lb/MMscf	0.2599 lb/hr	1.1382 tpy	27.83 lb/MMscf	0.2728 lb/hr
HAP (Total)		8.32 lb/MMscf	0.0776 lb/hr	0.3401 tpy	8.32 lb/MMscf	0.0815 lb/hr
Acetaldehyde						
Acrolein						
Benzene		9.28E-03 lb/MMscf	8.66E-05 lb/hr	3.79E-04 tpy	9.28E-03 lb/MMscf	9.09E-05 lb/hr
Biphenyl						
Butadiene (1,3-)						
Carbon Tetrachloride						
Chlorobenzene						
Chloroform						
Dichloropropene (1,3-)						
Ethylbenzene						
Ethylene Dibromide						
Formaldehyde		3.31E-01 lb/MMscf	3.09E-03 lb/hr	1.35E-02 tpy	3.31E-01 lb/MMscf	3.25E-03 lb/hr
Hexane (n-)		7.95E+00 lb/MMscf	7.42E-02 lb/hr	3.25E-01 tpy	7.95E+00 lb/MMscf	7.80E-02 lb/hr
Methanol						
Methylene Chloride						
Methylnaphthalene (2-)		1.06E-04 lb/MMscf	9.90E-07 lb/hr	4.34E-06 tpy	1.06E-04 lb/MMscf	1.04E-06 lb/hr
Naphthalene		2.69E-03 lb/MMscf	2.52E-05 lb/hr	1.10E-04 tpy	2.69E-03 lb/MMscf	2.64E-05 lb/hr
PAH						
Phenol						
Propylene Oxide						
Styrene						
Tetrachloroethane (1,1,2,2-)						
Toluene		1.50E-02 lb/MMscf	1.40E-04 lb/hr	6.14E-04 tpy	1.50E-02 lb/MMscf	1.47E-04 lb/hr
Trichloroethane (1,1,2-)						
Trimethylpentane (2,2,4-)						
Vinyl Chloride						
Xylenes						

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Maximum hourly emissions based on 105% of rated capacity.
3. Vendor provided data on: heat output and heat input.
4. CO2 and N2O emission factors based on 40 CFR 98, Subpart C, Table C-1 and 40 CFR 98, Subpart C, Table C-2, respectively.
5. NOX, CO and TOC (Total) emission factors based on vendor data.
6. SO2 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2 using Tariff (5 gr/100 scf).
7. PM10/2.5 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2.
8. Remaining TOC specie emission factors based on scaling of AP-42, Section 1.4 (Revised 3/98), Table 1.4-3 using vendor HC data.
   $EF_i = (EF_{HC}/EF_{TOC\text{-}AP42})\ (EF_{i\text{-}AP42})$

TABLE D-1B
Natural Gas Combustion
Hourly and Annual Emission Estimates
Uncontrolled

Application		Process Heater				
Combustion Process		Conventional				
Add-on Controls		None				
Package (Make: Model)		NATCO: N/A				
Burner (Make: Model)		Unknown: Unknown				
Fuel		Natural Gas				
Fuel Higher Heating Value (HHV)		1,020 BTU/scf			1,020 BTU/scf	
Heat Output at HHV		5.000 MMBTU/hr			5.250 MMBTU/hr	
Thermal Efficiency		74%			74%	
Operating Hours		8,760 hrs/yr				
Fuel Consumption		6,669 scfh			7,003 scfh	
		58.423 MMscf/yr				
Heat Input at HHV		6.803 MMBTU/hr			7.143 MMBTU/hr	
		59,592 MMBTU/yr	Uncontrolled			Uncontrolled
Pollutant	Control Efficiency	Uncontrolled	Average Hourly	Maximum Annual	Uncontrolled	Maximum Hourly
NO_X		98.43 lb/MMscf	0.6565 lb/hr	2.8754 tpy	98.43 lb/MMscf	0.6893 lb/hr
CO		150.00 lb/MMscf	1.0004 lb/hr	4.3818 tpy	150.00 lb/MMscf	1.0504 lb/hr
SO_2		14.29 lb/MMscf	0.0953 lb/hr	0.4173 tpy	14.29 lb/MMscf	0.1000 lb/hr
$PM_{10/2.5}$		7.60 lb/MMscf	0.0507 lb/hr	0.2220 tpy	7.60 lb/MMscf	0.0532 lb/hr
$CO_{2\text{-}e}$		120,338.86 lb/MMscf	802.5801 lb/hr	3,515.3010 tpy	120,338.86 lb/MMscf	842.7091 lb/hr
CO_2		120,017.45 lb/MMscf	800.4365 lb/hr	3,505.9120 tpy	120,017.45 lb/MMscf	840.4584 lb/hr
N_2O		0.23 lb/MMscf	0.0015 lb/hr	0.0066 tpy	0.23 lb/MMscf	0.0016 lb/hr
TOC (Total)		60.00 lb/MMscf	0.4002 lb/hr	1.7527 tpy	60.00 lb/MMscf	0.4202 lb/hr
Methane		10.16 lb/MMscf	0.0678 lb/hr	0.2968 tpy	10.16 lb/MMscf	0.0711 lb/hr
Ethane		13.69 lb/MMscf	0.0913 lb/hr	0.4000 tpy	13.69 lb/MMscf	0.0959 lb/hr
VOC (Total)		36.15 lb/MMscf	0.2411 lb/hr	1.0559 tpy	36.15 lb/MMscf	0.2531 lb/hr
VOC (non-HAP)		27.83 lb/MMscf	0.1856 lb/hr	0.8130 tpy	27.83 lb/MMscf	0.1949 lb/hr
HAP (Total)		8.32 lb/MMscf	0.0555 lb/hr	0.2429 tpy	8.32 lb/MMscf	0.0582 lb/hr
Acetaldehyde						
Acrolein						
Benzene		9.28E-03 lb/MMscf	6.19E-05 lb/hr	2.71E-04 tpy	9.28E-03 lb/MMscf	6.50E-05 lb/hr
Biphenyl						
Butadiene (1,3-)						
Carbon Tetrachloride						
Chlorobenzene						
Chloroform						
Dichloropropene (1,3-)						
Ethylbenzene						
Ethylene Dibromide						
Formaldehyde		3.31E-01 lb/MMscf	2.21E-03 lb/hr	9.68E-03 tpy	3.31E-01 lb/MMscf	2.32E-03 lb/hr
Hexane (n-)		7.95E+00 lb/MMscf	5.30E-02 lb/hr	2.32E-01 tpy	7.95E+00 lb/MMscf	5.57E-02 lb/hr
Methanol						
Methylene Chloride						
Methylnaphthalene (2-)		1.06E-04 lb/MMscf	7.07E-07 lb/hr	3.10E-06 tpy	1.06E-04 lb/MMscf	7.42E-07 lb/hr
Naphthalene		2.69E-03 lb/MMscf	1.80E-05 lb/hr	7.87E-05 tpy	2.69E-03 lb/MMscf	1.89E-05 lb/hr
PAH						
Phenol						
Propylene Oxide						
Styrene						
Tetrachloroethane (1,1,2,2-)						
Toluene		1.50E-02 lb/MMscf	1.00E-04 lb/hr	4.39E-04 tpy	1.50E-02 lb/MMscf	1.05E-04 lb/hr
Trichloroethane (1,1,2-)						
Trimethylpentane (2,2,4-)						
Vinyl Chloride						
Xylenes						

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Maximum hourly emissions based on 105% of rated capacity.
3. Vendor provided data on: heat output and heat input.
4. CO2 and N2O emission factors based on 40 CFR 98, Subpart C, Table C-1 and 40 CFR 98, Subpart C, Table C-2, respectively.
5. NOX, CO and TOC (Total) emission factors based on vendor data.
6. SO2 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2 using Tariff (5 gr/100 scf).
7. PM10/2.5 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2.
8. Remaining TOC specie emission factors based on scaling of AP-42, Section 1.4 (Revised 3/98), Table 1.4-3 using vendor HC data.
   $EF_i = (EF_{HC}/EF_{TOC\text{-}AP42})\ (EF_{i\text{-}AP42})$

TABLE D-1C
Natural Gas Combustion
Hourly and Annual Emission Estimates
Uncontrolled

Application		Boiler				
Combustion Process		Low NOx Burners				
Add-on Controls		None				
Package (Make: Model)		Lochinvar: CHN1801				
Burner (Make: Model)		Unknown: Unknown				
Fuel		Natural Gas				
Fuel Higher Heating Value (HHV)		1,020 BTU/scf			1,020 BTU/scf	
Heat Output at HHV		1.512 MMBTU/hr			1.588 MMBTU/hr	
Thermal Efficiency		84%			84%	
Operating Hours		8,760 hrs/yr				
Fuel Consumption		1,765 scfh			1,853 scfh	
		15.459 MMscf/yr				
Heat Input at HHV		1.800 MMBTU/hr			1.890 MMBTU/hr	
		15,768 MMBTU/yr	Uncontrolled			Uncontrolled
Pollutant	Control Efficiency	Uncontrolled	Average Hourly	Maximum Annual	Uncontrolled	Maximum Hourly
NO_X		36.91 lb/MMscf	0.0651 lb/hr	0.2853 tpy	36.91 lb/MMscf	0.0684 lb/hr
CO		84.00 lb/MMscf	0.1482 lb/hr	0.6493 tpy	84.00 lb/MMscf	0.1556 lb/hr
SO_2		14.29 lb/MMscf	0.0252 lb/hr	0.1104 tpy	14.29 lb/MMscf	0.0265 lb/hr
$PM_{10/2.5}$		7.60 lb/MMscf	0.0134 lb/hr	0.0587 tpy	7.60 lb/MMscf	0.0141 lb/hr
CO_{2-e}		120,142.36 lb/MMscf	212.0159 lb/hr	928.6298 tpy	120,142.36 lb/MMscf	222.6167 lb/hr
CO_2		120,017.45 lb/MMscf	211.7955 lb/hr	927.6643 tpy	120,017.45 lb/MMscf	222.3853 lb/hr
N_2O		0.23 lb/MMscf	0.0004 lb/hr	0.0017 tpy	0.23 lb/MMscf	0.0004 lb/hr
TOC (Total)		13.58 lb/MMscf	0.0240 lb/hr	0.1050 tpy	13.58 lb/MMscf	0.0252 lb/hr
Methane		2.30 lb/MMscf	0.0041 lb/hr	0.0178 tpy	2.30 lb/MMscf	0.0043 lb/hr
Ethane		3.10 lb/MMscf	0.0055 lb/hr	0.0240 tpy	3.10 lb/MMscf	0.0057 lb/hr
VOC (Total)		8.18 lb/MMscf	0.0144 lb/hr	0.0632 tpy	8.18 lb/MMscf	0.0152 lb/hr
VOC (non-HAP)		6.30 lb/MMscf	0.0111 lb/hr	0.0487 tpy	6.30 lb/MMscf	0.0117 lb/hr
HAP (Total)		1.88 lb/MMscf	0.0033 lb/hr	0.0145 tpy	1.88 lb/MMscf	0.0035 lb/hr
Acetaldehyde						
Acrolein						
Benzene		2.10E-03 lb/MMscf	3.71E-06 lb/hr	1.62E-05 tpy	2.10E-03 lb/MMscf	3.89E-06 lb/hr
Biphenyl						
Butadiene (1,3-)						
Carbon Tetrachloride						
Chlorobenzene						
Chloroform						
Dichloropropene (1,3-)						
Ethylbenzene						
Ethylene Dibromide						
Formaldehyde		7.50E-02 lb/MMscf	1.32E-04 lb/hr	5.80E-04 tpy	7.50E-02 lb/MMscf	1.39E-04 lb/hr
Hexane (n-)		1.80E+00 lb/MMscf	3.18E-03 lb/hr	1.39E-02 tpy	1.80E+00 lb/MMscf	3.34E-03 lb/hr
Methanol						
Methylene Chloride						
Methylnaphthalene (2-)		2.40E-05 lb/MMscf	4.24E-08 lb/hr	1.86E-07 tpy	2.40E-05 lb/MMscf	4.45E-08 lb/hr
Naphthalene		6.10E-04 lb/MMscf	1.08E-06 lb/hr	4.71E-06 tpy	6.10E-04 lb/MMscf	1.13E-06 lb/hr
PAH						
Phenol						
Propylene Oxide						
Styrene						
Tetrachloroethane (1,1,2,2-)						
Toluene		3.40E-03 lb/MMscf	6.00E-06 lb/hr	2.63E-05 tpy	3.40E-03 lb/MMscf	6.30E-06 lb/hr
Trichloroethane (1,1,2-)						
Trimethylpentane (2,2,4-)						
Vinyl Chloride						
Xylenes						

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Maximum hourly emissions based on 105% of rated capacity.
3. Vendor provided data on: heat output and heat input.
4. CO2 and N2O emission factors based on 40 CFR 98, Subpart C, Table C-1 and 40 CFR 98, Subpart C, Table C-2, respectively.
5. NOX emission factor based on vendor data.
6. SO2 and PM10/2.5 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2.
7. Remaining emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-3.

TABLE D-1D
Natural Gas Combustion
Hourly and Annual Emission Estimates
Uncontrolled

Application		Process Heater				
Combustion Process		Conventional				
Add-on Controls		None				
Package (Make: Model)		Sivalls: IH-3005-T2-150M				
Burner (Make: Model)		Unknown: Unknown				
Fuel		Natural Gas				
Fuel Higher Heating Value (HHV)		1,020 BTU/scf			1,020 BTU/scf	
Heat Output at HHV		0.150 MMBTU/hr			0.158 MMBTU/hr	
Thermal Efficiency		65%			65%	
Operating Hours		8,760 hrs/yr				
Fuel Consumption		226 scfh			238 scfh	
		1.982 MMscf/yr				
Heat Input at HHV		0.231 MMBTU/hr			0.242 MMBTU/hr	
		2,022 MMBTU/yr	Uncontrolled			Uncontrolled
Pollutant	Control Efficiency	Uncontrolled	Average Hourly	Maximum Annual	Uncontrolled	Maximum Hourly
NO_X		98.43 lb/MMscf	0.0223 lb/hr	0.0975 tpy	98.43 lb/MMscf	0.0234 lb/hr
CO		150.00 lb/MMscf	0.0339 lb/hr	0.1486 tpy	150.00 lb/MMscf	0.0356 lb/hr
SO_2		14.29 lb/MMscf	0.0032 lb/hr	0.0142 tpy	14.29 lb/MMscf	0.0034 lb/hr
$PM_{10/2.5}$		7.60 lb/MMscf	0.0017 lb/hr	0.0075 tpy	7.60 lb/MMscf	0.0018 lb/hr
$CO_{2\text{-}e}$		120,338.86 lb/MMscf	27.2260 lb/hr	119.2498 tpy	120,338.86 lb/MMscf	28.5873 lb/hr
CO_2		120,017.45 lb/MMscf	27.1533 lb/hr	118.9313 tpy	120,017.45 lb/MMscf	28.5109 lb/hr
N_2O		0.23 lb/MMscf	0.0001 lb/hr	0.0002 tpy	0.23 lb/MMscf	0.0001 lb/hr
TOC (Total)		60.00 lb/MMscf	0.0136 lb/hr	0.0595 tpy	60.00 lb/MMscf	0.0143 lb/hr
Methane		10.16 lb/MMscf	0.0023 lb/hr	0.0101 tpy	10.16 lb/MMscf	0.0024 lb/hr
Ethane		13.69 lb/MMscf	0.0031 lb/hr	0.0136 tpy	13.69 lb/MMscf	0.0033 lb/hr
VOC (Total)		36.15 lb/MMscf	0.0082 lb/hr	0.0358 tpy	36.15 lb/MMscf	0.0086 lb/hr
VOC (non-HAP)		27.83 lb/MMscf	0.0063 lb/hr	0.0276 tpy	27.83 lb/MMscf	0.0066 lb/hr
HAP (Total)		8.32 lb/MMscf	0.0019 lb/hr	0.0082 tpy	8.32 lb/MMscf	0.0020 lb/hr
Acetaldehyde						
Acrolein						
Benzene		9.28E-03 lb/MMscf	2.10E-06 lb/hr	9.19E-06 tpy	9.28E-03 lb/MMscf	2.20E-06 lb/hr
Biphenyl						
Butadiene (1,3-)						
Carbon Tetrachloride						
Chlorobenzene						
Chloroform						
Dichloropropene (1,3-)						
Ethylbenzene						
Ethylene Dibromide						
Formaldehyde		3.31E-01 lb/MMscf	7.50E-05 lb/hr	3.28E-04 tpy	3.31E-01 lb/MMscf	7.87E-05 lb/hr
Hexane (n-)		7.95E+00 lb/MMscf	1.80E-03 lb/hr	7.88E-03 tpy	7.95E+00 lb/MMscf	1.89E-03 lb/hr
Methanol						
Methylene Chloride						
Methylnaphthalene (2-)		1.06E-04 lb/MMscf	2.40E-08 lb/hr	1.05E-07 tpy	1.06E-04 lb/MMscf	2.52E-08 lb/hr
Naphthalene		2.69E-03 lb/MMscf	6.10E-07 lb/hr	2.67E-06 tpy	2.69E-03 lb/MMscf	6.40E-07 lb/hr
PAH						
Phenol						
Propylene Oxide						
Styrene						
Tetrachloroethane (1,1,2,2-)						
Toluene		1.50E-02 lb/MMscf	3.40E-06 lb/hr	1.49E-05 tpy	1.50E-02 lb/MMscf	3.57E-06 lb/hr
Trichloroethane (1,1,2-)						
Trimethylpentane (2,2,4-)						
Vinyl Chloride						
Xylenes						

NOTES

1. Fuel higher heating value selected to correspond to AP-42 emissions factors.
2. Maximum hourly emissions based on 105% of rated capacity.
3. Vendor provided data on: heat output and heat input.
4. CO2 and N2O emission factors based on 40 CFR 98, Subpart C, Table C-1 and 40 CFR 98, Subpart C, Table C-2, respectively.
5. NOX, CO and TOC (Total) emission factors based on vendor data.
6. SO2 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2 using Tariff (5 gr/100 scf).
7. PM10/2.5 emission factors based on AP-42, Section 1.4 (Revised 3/98), Table 1.4-2.
8. Remaining TOC specie emission factors based on scaling of AP-42, Section 1.4 (Revised 3/98), Table 1.4-3 using vendor HC data.
   $EF_i = (EF_{HC}/EF_{TOC\text{-}AP42})\,(EF_{i\text{-}AP42})$

TABLE E-1A
Flash Analysis
Maximum Hourly and Annual Emission Estimates

Station ID	WEYM-SV-V2				
Service	Pipeline Liquids				
Liquids Holding Capacity	587 gal			587 gal	
Liquids Input Rate	4,400 gal/yr			587 gal/hr	
Flash Gas Density	0.0769 lb/scf			0.0769 lb/scf	
Flash Factor	328.03 scf/bbl			328.03 scf/bbl	
Flash Gas Rate	34,365 scf/yr			4,582 scfh	
Flash Losses	2,644 lb/yr	Average	Maximum	353 lb/hr	Maximum
Flash Gas	100.00% by weight	0.3018 lb/hr	1.3220 tpy	100.00% by weight	352.5405 lb/hr
$CO_{2\text{-}e}$	1039.07% by weight	3.1363 lb/hr	13.7368 tpy	1039.07% by weight	3,663 lb/hr
CO_2	5.17% by weight	0.0156 lb/hr	0.0683 tpy	5.17% by weight	18.2173 lb/hr
TOC (Total)	94.73% by weight	0.2859 lb/hr	1.2523 tpy	94.73% by weight	333.9529 lb/hr
Methane	41.36% by weight	0.1248 lb/hr	0.5467 tpy	41.36% by weight	145.7974 lb/hr
Ethane	11.68% by weight	0.0353 lb/hr	0.1545 tpy	11.68% by weight	41.1888 lb/hr
VOC (Total)	41.69% by weight	0.1258 lb/hr	0.5511 tpy	41.69% by weight	146.9667 lb/hr
HAP (Total)	92.34% by weight	0.2787 lb/hr	1.2208 tpy	92.34% by weight	325.5503 lb/hr
Benzene	0.5089% by weight	0.0015 lb/hr	0.0067 tpy	0.5089% by weight	1.7940 lb/hr
Ethylbenzene	0.0275% by weight	0.0001 lb/hr	0.0004 tpy	0.0275% by weight	0.0970 lb/hr
Hexane (n-)	1.7932% by weight	0.0054 lb/hr	0.0237 tpy	1.7932% by weight	6.3218 lb/hr
Methanol					
Naphthalene					
Toluene	0.6253% by weight	0.0019 lb/hr	0.0083 tpy	0.6253% by weight	2.2044 lb/hr
Trimethylpentane (2,2,4-)	0.0091% by weight	0.0000 lb/hr	0.0001 tpy	0.0091% by weight	0.0322 lb/hr
Xylenes	0.3706% by weight	0.0011 lb/hr	0.0049 tpy	0.3706% by weight	1.3066 lb/hr

NOTES

1. Separator Characteristics: <u>Flash is represented for separators that receive majority of liquids, but flash may be emitted other separators.</u>

Orientation	Vertical Fixed Roof Tank	
Height/Length	12.00 ft	
Diameter	5.00 ft	
Capacity (physical)	1,763 gal	
Capacity (liquid)	587 gal	33% of physical capacity

2. Liquid input rates:
   a. maximum hourly based on operator experience; 587 gal
   b. maximum annual based on operating experience and safety factor; and 4,400 gal
   c. average hourly is just the maximum annual divided by 8,760 hrs/yr.
3. Flash gas density is 110% of the value extracted from TABLE E-0D.
   Density (TABLE E-0D): 0.0699 lb/scf Safety Factor: 110%
4. Flash factor extracted from TABLE E-0A.
5. Speciated emissions vapor weight percentages extracted from TABLE E-0D.

TABLE F-1A
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source	WEYM-SV-V1SD				
Service	Pipeline Liquids				
Capacity	530 gal			530 gal	
Temperature of Stored Liquid	59.64 °F			85.22 °F	
Vapor Pressure	5.2170 psia			8.2678 psia	
Pumping Rate	150 gal/min			150 gal/min	
Throughput	0.20 turnover/yr				
	106 gal/yr			530 gal/hr	
Standing Losses				**July**	
				744 hrs/month	
				40.3036 lbs/month	
	261.9182 lb/yr			0.0542 lb/hr	
Working Losses	**8.20E-03** lb/gal			**1.04E-02** lb/gal	
	0.8664 lb/yr	Average	Maximum	5.5304 lb/hr	Maximum
Residual Liquid — Stand	358.84% by weight	0.1073 lb/hr	0.4699 tpy	358.84% by weight	0.1944 lb/hr
Residual Liquid — Work		0.0004 lb/hr	0.0016 tpy		19.8453 lb/hr
Residual Liquid — Total		0.1076 lb/hr	0.4715 tpy		20.0397 lb/hr
CO_{2-e}	5398.27% by weight	1.6194 lb/hr	7.0929 tpy	5398.27% by weight	301 lb/hr
CO_2	7.83% by weight	0.0023 lb/hr	0.0103 tpy	7.83% by weight	0.4375 lb/hr
TOC (Total)	351.00% by weight	0.1053 lb/hr	0.4612 tpy	351.00% by weight	19.6022 lb/hr
Methane	215.62% by weight	0.0647 lb/hr	0.2833 tpy	215.62% by weight	12.0414 lb/hr
Ethane	35.39% by weight	0.0106 lb/hr	0.0465 tpy	35.39% by weight	1.9762 lb/hr
VOC (Total)	100.00% by weight	0.0300 lb/hr	0.1314 tpy	100.00% by weight	5.5846 lb/hr
HAP (Total)	6.23% by weight	0.0019 lb/hr	0.0082 tpy	6.23% by weight	0.3478 lb/hr
Benzene	1.5063% by weight	4.52E-04 lb/hr	1.98E-03 tpy	1.5063% by weight	8.41E-02 lb/hr
Ethylbenzene	0.0477% by weight	1.43E-05 lb/hr	6.26E-05 tpy	0.0477% by weight	2.66E-03 lb/hr
Hexane (n-)	2.8866% by weight	8.66E-04 lb/hr	3.79E-03 tpy	2.8866% by weight	1.61E-01 lb/hr
Methanol					
Naphthalene					
Toluene	1.3668% by weight	4.10E-04 lb/hr	1.80E-03 tpy	1.3668% by weight	7.63E-02 lb/hr
Trimethylpentane (2,2,4-)	0.0139% by weight	4.17E-06 lb/hr	1.82E-05 tpy	0.0139% by weight	7.75E-04 lb/hr
Xylenes	0.4073% by weight	1.22E-04 lb/hr	5.35E-04 tpy	0.4073% by weight	2.27E-02 lb/hr

NOTES

1. Tank Characteristics: TANKS 4.09d

Orientation	Vertical Fixed Roof Tank		Above Ground?	Yes	
Height/Length	10.83 ft	10.83 ft	Shell/Roof Color	Gray/Medium	or less solar absorptance
Diameter	5.00 ft		Shell Condition	Good	
Capacity (estimated)	1,591 gal		Vacuum Setting	-0.03 psig	
Capacity (nominal)	1,590 gal		Pressure Setting	0.03 psig	

2. Stored Liquid Characteristics:

Basis: USEPA TANKS 4.09d — MET Station: Boston, Massachusetts

Material: Gasoline (RVP 10) — Selection based on VOC vapor pressure (see TABLE F-0).

Liquid Molecular Weight: 92.00 lb/lb-mol — Vapor Molecular Weight: 66.00 lb/lb-mol

Monthly Data

	Days	Vapor Pressure		Liquid Surface Temperature		TANKS Output		TANKS
		avg	max	avg	max	standing	working	Flow
January	31	3.9399	4.3904	46.21	51.55	8.9064	9.8440	1,590
February	28	4.1158	4.7065	48.35	55.05	10.6806	10.2837	1,590
March	31	4.5882	5.3917	53.76	62.02	16.6384	11.4639	1,590
April	30	5.1466	6.2208	59.61	69.56	22.4244	12.8592	1,590
May	31	5.7769	7.1549	65.63	77.15	31.2891	14.4340	1,590
June	30	6.3503	7.9502	70.66	83.01	37.1114	15.8667	1,590
July	31	6.6403	8.2678	73.07	85.22	40.3036	16.5913	1,590
August	31	6.4129	7.8244	71.19	82.11	34.3226	16.0230	1,590
September	30	5.8414	6.9478	66.21	75.53	24.7418	14.5952	1,590
October	31	5.1535	5.9372	59.68	67.07	17.1043	12.8765	1,590
November	30	4.5697	5.0773	53.56	58.91	10.2237	11.4177	1,590
December	31	4.0686	4.4783	47.78	52.55	8.1721	10.1658	1,590
ALL	365	5.2170	8.2678	59.64	85.22	261.9182	156.4210	19,080

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. Speciation of emissions is based on vapor weight percentages in TABLE F-0 normalized on VOC to assure methodology is conservative.

TABLE F-1B
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source		WEYM-SV-V1C1				
Service		Pipeline Liquids				
Capacity		530 gal			530 gal	
Temperature of Stored Liquid		59.64 °F			85.22 °F	
Vapor Pressure		5.2170 psia			8.2678 psia	
Pumping Rate		150 gal/min			150 gal/min	
Throughput		0.20 turnover/yr				
		106 gal/yr			530 gal/hr	
Standing Losses					**July**	
					744 hrs/month	
					40.3036 lbs/month	
		261.9182 lb/yr			0.0542 lb/hr	
Working Losses		**8.20E-03** lb/gal			**1.04E-02** lb/gal	
		0.8664 lb/yr	Average	Maximum	5.5304 lb/hr	Maximum
Residual Liquid	Stand	358.84% by weight	0.1073 lb/hr	0.4699 tpy	358.84% by weight	0.1944 lb/hr
	Work		0.0004 lb/hr	0.0016 tpy		19.8453 lb/hr
	Total		0.1076 lb/hr	0.4715 tpy		20.0397 lb/hr
CO_{2-e}		5398.27% by weight	1.6194 lb/hr	7.0929 tpy	5398.27% by weight	301 lb/hr
CO_2		7.83% by weight	0.0023 lb/hr	0.0103 tpy	7.83% by weight	0.4375 lb/hr
TOC (Total)		351.00% by weight	0.1053 lb/hr	0.4612 tpy	351.00% by weight	19.6022 lb/hr
Methane		215.62% by weight	0.0647 lb/hr	0.2833 tpy	215.62% by weight	12.0414 lb/hr
Ethane		35.39% by weight	0.0106 lb/hr	0.0465 tpy	35.39% by weight	1.9762 lb/hr
VOC (Total)		100.00% by weight	0.0300 lb/hr	0.1314 tpy	100.00% by weight	5.5846 lb/hr
HAP (Total)		6.23% by weight	0.0019 lb/hr	0.0082 tpy	6.23% by weight	0.3478 lb/hr
Benzene		1.5063% by weight	4.52E-04 lb/hr	1.98E-03 tpy	1.5063% by weight	8.41E-02 lb/hr
Ethylbenzene		0.0477% by weight	1.43E-05 lb/hr	6.26E-05 tpy	0.0477% by weight	2.66E-03 lb/hr
Hexane (n-)		2.8866% by weight	8.66E-04 lb/hr	3.79E-03 tpy	2.8866% by weight	1.61E-01 lb/hr
Methanol						
Naphthalene						
Toluene		1.3668% by weight	4.10E-04 lb/hr	1.80E-03 tpy	1.3668% by weight	7.63E-02 lb/hr
Trimethylpentane (2,2,4-)		0.0139% by weight	4.17E-06 lb/hr	1.82E-05 tpy	0.0139% by weight	7.75E-04 lb/hr
Xylenes		0.4073% by weight	1.22E-04 lb/hr	5.35E-04 tpy	0.4073% by weight	2.27E-02 lb/hr

NOTES

1. Tank Characteristics:		TANKS 4.09d			
Orientation	Vertical Fixed Roof Tank		Above Ground?	Yes	
Height/Length	10.83 ft	10.83 ft	Shell/Roof Color	Gray/Medium	or less solar absorptance
Diameter	5.00 ft		Shell Condition	Good	
Capacity (estimated)	1,591 gal		Vacuum Setting	-0.03 psig	
Capacity (nominal)	1,590 gal		Pressure Setting	0.03 psig	
2. Stored Liquid Characteristics:					
Basis	USEPA TANKS 4.09d	MET Station:	Boston, Massachusetts		
Material	Gasoline (RVP 10)	Selection based on VOC vapor pressure (see TABLE F-0).			
Liquid Molecular Weight	92.00 lb/lb-mol	Vapor Molecular Weight		66.00 lb/lb-mol	

Monthly Data	Days	Vapor Pressure		Liquid Surface Temperature		TANKS Output		TANKS
		avg	max	avg	max	standing	working	Flow
January	31	3.9399	4.3904	46.21	51.55	8.9064	9.8440	1,590
February	28	4.1158	4.7065	48.35	55.05	10.6806	10.2837	1,590
March	31	4.5882	5.3917	53.76	62.02	16.6384	11.4639	1,590
April	30	5.1466	6.2208	59.61	69.56	22.4244	12.8592	1,590
May	31	5.7769	7.1549	65.63	77.15	31.2891	14.4340	1,590
June	30	6.3503	7.9502	70.66	83.01	37.1114	15.8667	1,590
July	31	6.6403	8.2678	73.07	85.22	40.3036	16.5913	1,590
August	31	6.4129	7.8244	71.19	82.11	34.3226	16.0230	1,590
September	30	5.8414	6.9478	66.21	75.53	24.7418	14.5952	1,590
October	31	5.1535	5.9372	59.68	67.07	17.1043	12.8765	1,590
November	30	4.5697	5.0773	53.56	58.91	10.2237	11.4177	1,590
December	31	4.0686	4.4783	47.78	52.55	8.1721	10.1658	1,590
ALL	365	5.2170	8.2678	59.64	85.22	261.9182	156.4210	19,080

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. Speciation of emissions is based on vapor weight percentages in TABLE F-0 normalized on VOC to assure methodology is conservative.

TABLE F-1C
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source		WEYM-SV-V2				
Service		Pipeline Liquids				
Capacity		587 gal			587 gal	
Temperature of Stored Liquid		59.64 °F			85.22 °F	
Vapor Pressure		5.2170 psia			8.2678 psia	
Pumping Rate		150 gal/min			150 gal/min	
Throughput		7.50 turnover/yr				
		4,400 gal/yr			587 gal/hr	
Standing Losses					**July**	
					744 hrs/month	
					41.5584 lbs/month	
		271.0744 lb/yr			0.0559 lb/hr	
Working Losses		**8.20E-03** lb/gal			**1.04E-02** lb/gal	
		36.0719 lb/yr	Average	Maximum	6.1217 lb/hr	Maximum
Residual Liquid	Stand	358.84% by weight	0.1110 lb/hr	0.4864 tpy	358.84% by weight	0.2004 lb/hr
	Work		0.0148 lb/hr	0.0647 tpy		21.9671 lb/hr
	Total		0.1258 lb/hr	0.5511 tpy		22.1675 lb/hr
CO_{2-e}		5398.27% by weight	1.8928 lb/hr	8.2903 tpy	5398.27% by weight	333 lb/hr
CO_2		7.83% by weight	0.0027 lb/hr	0.0120 tpy	7.83% by weight	0.4839 lb/hr
TOC (Total)		351.00% by weight	0.1231 lb/hr	0.5390 tpy	351.00% by weight	21.6836 lb/hr
Methane		215.62% by weight	0.0756 lb/hr	0.3311 tpy	215.62% by weight	13.3199 lb/hr
Ethane		35.39% by weight	0.0124 lb/hr	0.0543 tpy	35.39% by weight	2.1861 lb/hr
VOC (Total)		100.00% by weight	0.0351 lb/hr	0.1536 tpy	100.00% by weight	6.1776 lb/hr
HAP (Total)		6.23% by weight	0.0022 lb/hr	0.0096 tpy	6.23% by weight	0.3848 lb/hr
Benzene		1.5063% by weight	5.28E-04 lb/hr	2.31E-03 tpy	1.5063% by weight	9.31E-02 lb/hr
Ethylbenzene		0.0477% by weight	1.67E-05 lb/hr	7.32E-05 tpy	0.0477% by weight	2.94E-03 lb/hr
Hexane (n-)		2.8866% by weight	1.01E-03 lb/hr	4.43E-03 tpy	2.8866% by weight	1.78E-01 lb/hr
Methanol						
Naphthalene						
Toluene		1.3668% by weight	4.79E-04 lb/hr	2.10E-03 tpy	1.3668% by weight	8.44E-02 lb/hr
Trimethylpentane (2,2,4-)		0.0139% by weight	4.87E-06 lb/hr	2.13E-05 tpy	0.0139% by weight	8.58E-04 lb/hr
Xylenes		0.4073% by weight	1.43E-04 lb/hr	6.26E-04 tpy	0.4073% by weight	2.52E-02 lb/hr

NOTES

1. Tank Characteristics: TANKS 4.09d

Orientation	Vertical Fixed Roof Tank	Above Ground?	Yes
Height/Length	12.00 ft	Shell/Roof Color	Gray/Medium (or less solar absorptance)
Diameter	5.00 ft	Shell Condition	Good
Capacity (estimated)	1,763 gal	Vacuum Setting	-0.03 psig
Capacity (nominal)	1,760 gal	Pressure Setting	0.03 psig

2. Stored Liquid Characteristics:

Basis	USEPA TANKS 4.09d	MET Station:	Boston, Massachusetts
Material	Gasoline (RVP 10)	Selection based on VOC vapor pressure (see TABLE F-0).	
Liquid Molecular Weight	92.00 lb/lb-mol	Vapor Molecular Weight	66.00 lb/lb-mol

Monthly Data

	Days	Vapor Pressure		Liquid Surface Temperature		TANKS Output		TANKS
		avg	max	avg	max	standing	working	Flow
January	31	3.9399	4.3904	46.21	51.55	9.2920	10.8965	1,760
February	28	4.1158	4.7065	48.35	55.05	11.1316	11.3832	1,760
March	31	4.5882	5.3917	53.76	62.02	17.2971	12.6896	1,760
April	30	5.1466	6.2208	59.61	69.56	23.2510	14.2341	1,760
May	31	5.7769	7.1549	65.63	77.15	32.3594	15.9772	1,760
June	30	6.3503	7.9502	70.66	83.01	38.3028	17.5631	1,760
July	31	6.6403	8.2678	73.07	85.22	41.5584	18.3652	1,760
August	31	6.4129	7.8244	71.19	82.11	35.4171	17.7362	1,760
September	30	5.8414	6.9478	66.21	75.53	25.5820	16.1557	1,760
October	31	5.1535	5.9372	59.68	67.07	17.7342	14.2532	1,760
November	30	4.5697	5.0773	53.56	58.91	10.6293	12.6384	1,760
December	31	4.0686	4.4783	47.78	52.55	8.5195	11.2527	1,760
ALL	365	5.2170	8.2678	59.64	85.22	271.0744	173.1452	21,120

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. Speciation of emissions is based on vapor weight percentages in TABLE F-0 normalized on VOC to assure methodology is conservative.

TABLE F-1D
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source		WEYM-SV-V4SD				
Service		Pipeline Liquids				
Capacity		43 gal			43 gal	
Temperature of Stored Liquid		59.64 °F			85.22 °F	
Vapor Pressure		5.2170 psia			8.2678 psia	
Pumping Rate		150 gal/min			150 gal/min	
Throughput		0.20 turnover/yr				
		9 gal/yr			43 gal/hr	
Standing Losses					**July**	
					744 hrs/month	
					3.9707 lbs/month	
		25.4567 lb/yr			0.0053 lb/hr	
Working Losses		**8.20E-03** lb/gal			**1.04E-02** lb/gal	
		0.0708 lb/yr	Average	Maximum	0.4522 lb/hr	Maximum
Residual Liquid	Stand	358.84% by weight	0.0104 lb/hr	0.0457 tpy	358.84% by weight	0.0192 lb/hr
	Work		0.0000 lb/hr	0.0001 tpy		1.6226 lb/hr
	Total		0.0105 lb/hr	0.0458 tpy		1.6417 lb/hr
$CO_{2\text{-}e}$		5398.27% by weight	0.1573 lb/hr	0.6890 tpy	5398.27% by weight	25 lb/hr
CO_2		7.83% by weight	0.0002 lb/hr	0.0010 tpy	7.83% by weight	0.0358 lb/hr
TOC (Total)		351.00% by weight	0.0102 lb/hr	0.0448 tpy	351.00% by weight	1.6059 lb/hr
Methane		215.62% by weight	0.0063 lb/hr	0.0275 tpy	215.62% by weight	0.9865 lb/hr
Ethane		35.39% by weight	0.0010 lb/hr	0.0045 tpy	35.39% by weight	0.1619 lb/hr
VOC (Total)		100.00% by weight	0.0029 lb/hr	0.0128 tpy	100.00% by weight	0.4575 lb/hr
HAP (Total)		6.23% by weight	0.0002 lb/hr	0.0008 tpy	6.23% by weight	0.0285 lb/hr
Benzene		1.5063% by weight	4.39E-05 lb/hr	1.92E-04 tpy	1.5063% by weight	6.89E-03 lb/hr
Ethylbenzene		0.0477% by weight	1.39E-06 lb/hr	6.08E-06 tpy	0.0477% by weight	2.18E-04 lb/hr
Hexane (n-)		2.8866% by weight	8.41E-05 lb/hr	3.68E-04 tpy	2.8866% by weight	1.32E-02 lb/hr
Methanol						
Naphthalene						
Toluene		1.3668% by weight	3.98E-05 lb/hr	1.74E-04 tpy	1.3668% by weight	6.25E-03 lb/hr
Trimethylpentane (2,2,4-)		0.0139% by weight	4.05E-07 lb/hr	1.77E-06 tpy	0.0139% by weight	6.35E-05 lb/hr
Xylenes		0.4073% by weight	1.19E-05 lb/hr	5.20E-05 tpy	0.4073% by weight	1.86E-03 lb/hr

NOTES

1. Tank Characteristics:

		TANKS 4.09d			
Orientation	Vertical Fixed Roof Tank		Above Ground?	Yes	
Height/Length	8.00 ft		Shell/Roof Color	Gray/Medium	or less solar absorptance
Diameter	1.67 ft	1.67 ft	Shell Condition	Good	
Capacity (estimated)	131 gal		Vacuum Setting	-0.03 psig	
Capacity (nominal)	130 gal		Pressure Setting	0.03 psig	

2. Stored Liquid Characteristics:

Basis	USEPA TANKS 4.09d	MET Station:	Boston, Massachusetts
Material	Gasoline (RVP 10)	Selection based on VOC vapor pressure (see TABLE F-0).	
Liquid Molecular Weight	92.00 lb/lb-mol	Vapor Molecular Weight	66.00 lb/lb-mol

Monthly Data

	Days	Vapor Pressure avg	Vapor Pressure max	Liquid Surface Temperature avg	Liquid Surface Temperature max	TANKS Output standing	TANKS Output working	TANKS Flow
January	31	3.9399	4.3904	46.21	51.55	0.8407	0.8049	130
February	28	4.1158	4.7065	48.35	55.05	1.0118	0.8408	130
March	31	4.5882	5.3917	53.76	62.02	1.5907	0.9373	130
April	30	5.1466	6.2208	59.61	69.56	2.1644	1.0514	130
May	31	5.7769	7.1549	65.63	77.15	3.0486	1.1801	130
June	30	6.3503	7.9502	70.66	83.01	3.6433	1.2973	130
July	31	6.6403	8.2678	73.07	85.22	3.9707	1.3565	130
August	31	6.4129	7.8244	71.19	82.11	3.3722	1.3101	130
September	30	5.8414	6.9478	66.21	75.53	2.4128	1.1933	130
October	31	5.1535	5.9372	59.68	67.07	1.6511	1.0528	130
November	30	4.5697	5.0773	53.56	58.91	0.9771	0.9335	130
December	31	4.0686	4.4783	47.78	52.55	0.7735	0.8312	130
ALL	365	5.2170	8.2678	59.64	85.22	25.4567	12.7891	1,560

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. Speciation of emissions is based on vapor weight percentages in TABLE F-0 normalized on VOC to assure methodology is conservative.

TABLE F-1E
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source		WEYM-TK-V5				
Service		Pipeline Liquids				
Capacity		2,200 gal			2,200 gal	
Temperature of Stored Liquid		59.64 °F			85.22 °F	
Vapor Pressure		5.2170 psia			8.2678 psia	
Pumping Rate		150 gal/min			150 gal/min	
Throughput		2.00 turnover/yr				
		4,400 gal/yr			2,200 gal/hr	
Standing Losses					**July**	
					744 hrs/month	
					85.5506 lbs/month	
		545.1562 lb/yr			0.1150 lb/hr	
Working Losses		**8.20E-03** lb/gal			**1.04E-02** lb/gal	
		36.0719 lb/yr	Average	Maximum	22.9565 lb/hr	Maximum
Residual Liquid	Stand	358.84% by weight	0.2233 lb/hr	0.9781 tpy	358.84% by weight	0.4126 lb/hr
	Work		0.0148 lb/hr	0.0647 tpy		82.3766 lb/hr
	Total		0.2381 lb/hr	1.0428 tpy		82.7892 lb/hr
CO_{2-e}		5398.27% by weight	3.5818 lb/hr	15.6881 tpy	5398.27% by weight	1,245 lb/hr
CO_2		7.83% by weight	0.0052 lb/hr	0.0228 tpy	7.83% by weight	1.8074 lb/hr
TOC (Total)		351.00% by weight	0.2329 lb/hr	1.0201 tpy	351.00% by weight	80.9819 lb/hr
Methane		215.62% by weight	0.1431 lb/hr	0.6266 tpy	215.62% by weight	49.7461 lb/hr
Ethane		35.39% by weight	0.0235 lb/hr	0.1028 tpy	35.39% by weight	8.1643 lb/hr
VOC (Total)		100.00% by weight	0.0664 lb/hr	0.2906 tpy	100.00% by weight	23.0715 lb/hr
HAP (Total)		6.23% by weight	0.0041 lb/hr	0.0181 tpy	6.23% by weight	1.4370 lb/hr
Benzene		1.5063% by weight	9.99E-04 lb/hr	4.38E-03 tpy	1.5063% by weight	3.48E-01 lb/hr
Ethylbenzene		0.0477% by weight	3.16E-05 lb/hr	1.39E-04 tpy	0.0477% by weight	1.10E-02 lb/hr
Hexane (n-)		2.8866% by weight	1.92E-03 lb/hr	8.39E-03 tpy	2.8866% by weight	6.66E-01 lb/hr
Methanol						
Naphthalene						
Toluene		1.3668% by weight	9.07E-04 lb/hr	3.97E-03 tpy	1.3668% by weight	3.15E-01 lb/hr
Trimethylpentane (2,2,4-)		0.0139% by weight	9.21E-06 lb/hr	4.04E-05 tpy	0.0139% by weight	3.20E-03 lb/hr
Xylenes		0.4073% by weight	2.70E-04 lb/hr	1.18E-03 tpy	0.4073% by weight	9.40E-02 lb/hr

NOTES

1. Tank Characteristics: TANKS 4.09d

Orientation	Vertical Fixed Roof Tank	Above Ground?	Yes
Height/Length	6.00 ft	Shell/Roof Color	Gray/Medium or less solar absorptance
Diameter	8.00 ft	Shell Condition	Good
Capacity (estimated)	2,256 gal	Vacuum Setting	-0.03 psig
Capacity (nominal)	2,200 gal	Pressure Setting	0.03 psig

2. Stored Liquid Characteristics:

Basis	USEPA TANKS 4.09d	MET Station:	Boston, Massachusetts
Material	Gasoline (RVP 10)	Selection based on VOC vapor pressure (see TABLE F-0).	
Liquid Molecular Weight	92.00 lb/lb-mol	Vapor Molecular Weight	66.00 lb/lb-mol

Monthly Data

	Days	Vapor Pressure		Liquid Surface Temperature		TANKS Output		TANKS
		avg	max	avg	max	standing	working	Flow
January	31	3.9399	4.3904	46.21	51.55	17.7688	13.6207	2,200
February	28	4.1158	4.7065	48.35	55.05	21.4211	14.2290	2,200
March	31	4.5882	5.3917	53.76	62.02	33.8101	15.8620	2,200
April	30	5.1466	6.2208	59.61	69.56	46.1992	17.7926	2,200
May	31	5.7769	7.1549	65.63	77.15	65.3509	19.9715	2,200
June	30	6.3503	7.9502	70.66	83.01	78.3712	21.9539	2,200
July	31	6.6403	8.2678	73.07	85.22	85.5506	22.9565	2,200
August	31	6.4129	7.8244	71.19	82.11	72.5640	22.1702	2,200
September	30	5.8414	6.9478	66.21	75.53	51.7437	20.1947	2,200
October	31	5.1535	5.9372	59.68	67.07	35.2443	17.8165	2,200
November	30	4.5697	5.0773	53.56	58.91	20.7648	15.7981	2,200
December	31	4.0686	4.4783	47.78	52.55	16.3673	14.0659	2,200
ALL	365	5.2170	8.2678	59.64	85.22	545.1562	216.4315	26,400

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. Speciation of emissions is based on vapor weight percentages in TABLE F-0 normalized on VOC to assure methodology is conservative.

TABLE F-1F
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source		WEYM-TK-OIL1				
Service		Oil				
Capacity		570 gal			570 gal	
Temperature of Stored Liquid		59.64 °F			85.22 °F	
Vapor Pressure		0.0067 psia			0.0141 psia	
Pumping Rate		150 gal/min			150 gal/min	
Throughput		365.00 turnover/yr				
		208,050 gal/yr			570 gal/hr	
Standing Losses					**July**	
					744 hrs/month	
					0.0252 lbs/month	
		0.1582 lb/yr			0.00003 lb/hr	
Working Losses		**2.07E-05** lb/gal			**3.07E-05** lb/gal	
		4.3031 lb/yr	Average	Maximum	0.0175 lb/hr	Maximum
Liquid	Stand	100.00% by weight	0.0000 lb/hr	0.0001 tpy	100.00% by weight	0.0000 lb/hr
	Work		0.0005 lb/hr	0.0022 tpy		0.0175 lb/hr
	Total		0.0005 lb/hr	0.0022 tpy		0.0175 lb/hr
TOC (Total)		100.00% by weight	0.0005 lb/hr	0.0022 tpy	100.00% by weight	0.0175 lb/hr
Methane						
Ethane						
VOC (Total)		100.00% by weight	0.0005 lb/hr	0.0022 tpy	100.00% by weight	0.0175 lb/hr
HAP (Total)						
Benzene						
Ethylbenzene						
Hexane (n-)						
Methanol						
Naphthalene						
Toluene						
Trimethylpentane (2,2,4-)						
Xylenes						

NOTES

1. Tank Characteristics: TANKS 4.09d

Orientation	Vertical Fixed Roof Tank	Above Ground?	Yes	
Height/Length	6.00 ft	Shell/Roof Color	Gray/Medium	or less solar absorptance
Diameter	4.00 ft	Shell Condition	Good	
Capacity (estimated)	564 gal	Vacuum Setting	-0.03 psig	
Capacity (nominal)	570 gal	Pressure Setting	0.03 psig	

2. Stored Liquid Characteristics:

Basis: USEPA TANKS 4.09d — MET Station: Boston, Massachusetts
Material: Distillate fuel oil no. 2 — Selected purely for a worst-case scenario.
Liquid Molecular Weight: 188.00 lb/lb-mol — Vapor Molecular Weight: 130.00 lb/lb-mol

Monthly Data	Days	Vapor Pressure avg	Vapor Pressure max	Liquid Surface Temperature avg	Liquid Surface Temperature max	TANKS Output standing	TANKS Output working	TANKS Flow
January	31	0.0040	0.0048	46.21	51.55	0.0046	0.0070	570
February	28	0.0043	0.0055	48.35	55.05	0.0057	0.0075	570
March	31	0.0053	0.0070	53.76	62.02	0.0095	0.0093	570
April	30	0.0064	0.0089	59.61	69.56	0.0135	0.0113	570
May	31	0.0079	0.0111	65.63	77.15	0.0195	0.0139	570
June	30	0.0092	0.0132	70.66	83.01	0.0232	0.0162	570
July	31	0.0099	0.0141	73.07	85.22	0.0252	0.0175	570
August	31	0.0094	0.0128	71.19	82.11	0.0214	0.0165	570
September	30	0.0081	0.0107	66.21	75.53	0.0154	0.0142	570
October	31	0.0064	0.0083	59.68	67.07	0.0102	0.0114	570
November	30	0.0052	0.0063	53.56	58.91	0.0057	0.0092	570
December	31	0.0042	0.0050	47.78	52.55	0.0043	0.0074	570
ALL	365	0.0067	0.0141	59.64	85.22	0.1582	0.1415	6,840

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. There is no basis for speciation of emissions.

TABLE F-1G
Volatile Organic Liquids Storage Tanks
Hourly and Annual Emission Estimates
Standing & Working Losses

Source		WEYM-TK-OW1				
Service		Oily Water				
Capacity		3,000 gal			3,000 gal	
Temperature of Stored Liquid		59.64 °F			85.22 °F	
Vapor Pressure		0.0067 psia			0.0141 psia	
Pumping Rate		150 gal/min			150 gal/min	
Throughput		12.00 turnover/yr				
		36,000 gal/yr			3,000 gal/hr	
Standing Losses					**July**	
					744 hrs/month	
					0.1595 lbs/month	
		1.0020 lb/yr			0.00021 lb/hr	
Working Losses		**2.07E-05** lb/gal			**3.07E-05** lb/gal	
		0.7446 lb/yr	Average	Maximum	0.0921 lb/hr	Maximum
Liquid	Stand	100.00% by weight	0.0001 lb/hr	0.0005 tpy	100.00% by weight	0.0002 lb/hr
	Work		0.0001 lb/hr	0.0004 tpy		0.0921 lb/hr
	Total		0.0002 lb/hr	0.0009 tpy		0.0923 lb/hr
TOC (Total)		100.00% by weight	0.0002 lb/hr	0.0009 tpy	100.00% by weight	0.0923 lb/hr
Methane						
Ethane						
VOC (Total)		100.00% by weight	0.0002 lb/hr	0.0009 tpy	100.00% by weight	0.0923 lb/hr
HAP (Total)						
Benzene						
Ethylbenzene						
Hexane (n-)						
Methanol						
Naphthalene						
Toluene						
Trimethylpentane (2,2,4-)						
Xylenes						

NOTES

1. Tank Characteristics:		TANKS 4.09d			
Orientation	Horizontal Tank		Above Ground?	Yes	
Height/Length	18.00 ft		Shell/Roof Color	Gray/Medium	or less solar
Diameter	5.38 ft	5.38 ft	Shell Condition	Good	absorptance
Capacity (estimated)	3,055 gal		Vacuum Setting	-0.03 psig	
Capacity (nominal)	3,000 gal		Pressure Setting	0.03 psig	

2. Stored Liquid Characteristics:

Basis	USEPA TANKS 4.09d	MET Station:	Boston, Massachusetts
Material	Distillate fuel oil no. 2	Selected purely for a worst-case scenario.	
Liquid Molecular Weight	188.00 lb/lb-mol	Vapor Molecular Weight	130.00 lb/lb-mol

Monthly Data	Days	Vapor Pressure		Liquid Surface Temperature		TANKS Output		TANKS
		avg	max	avg	max	standing	working	Flow
January	31	0.0040	0.0048	46.21	51.55	0.0294	0.0369	3,000
February	28	0.0043	0.0055	48.35	55.05	0.0362	0.0396	3,000
March	31	0.0053	0.0070	53.76	62.02	0.0605	0.0488	3,000
April	30	0.0064	0.0089	59.61	69.56	0.0853	0.0596	3,000
May	31	0.0079	0.0111	65.63	77.15	0.1237	0.0734	3,000
June	30	0.0092	0.0132	70.66	83.01	0.1469	0.0854	3,000
July	31	0.0099	0.0141	73.07	85.22	0.1595	0.0921	3,000
August	31	0.0094	0.0128	71.19	82.11	0.1355	0.0869	3,000
September	30	0.0081	0.0107	66.21	75.53	0.0973	0.0748	3,000
October	31	0.0064	0.0083	59.68	67.07	0.0643	0.0598	3,000
November	30	0.0052	0.0063	53.56	58.91	0.0363	0.0484	3,000
December	31	0.0042	0.0050	47.78	52.55	0.0271	0.0389	3,000
ALL	365	0.0067	0.0141	59.64	85.22	1.0020	0.7446	36,000

3. Emission Estimate Basis: USEPA TANKS 4.09d & TCEQ RG-166/01
4. There is no basis for speciation of emissions.

TABLE F-1H
Volatile Organic Liquids Loading (Tanker Trucks)
Hourly and Annual Emission Estimates

Source	WEYM-TL-PL				
Supply Vessel	WEYM-TK-V5				
	Pipeline Liquids				
	2,200 gal			2,200 gal	
Tanker Truck Service	Dedicated Normal			Dedicated Normal	
Loading Method	Submerged			Submerged	
Saturation Factor	0.60 n.d.			0.60 n.d.	
Vapor Molecular Weight	66.00 lb/lb-mol			66.00 lb/lb-mol	
Bulk Liquid Temperature	59.64 °F			85.22 °F	
	519.64 R			545.22 R	
Vapor Pressure	5.2170 psia			8.2678 psia	
Loading Loss Factor	4.9537 lb/kgal			7.4823 lb/kgal	
Pumping Rate				150 gpm	
Throughput	2.00 turnover/yr				
	4,400 gal/yr			2,200 gal/hr	
Loading Losses	21.7963 lb/yr	Average	Maximum	16.4610 lb/hr	Maximum
Residual Liquid	358.84% by weight	0.0089 lb/hr	0.0391 tpy	358.84% by weight	59.0682 lb/hr
$CO_{2\text{-}e}$	5398.27% by weight	0.1343 lb/hr	0.5883 tpy	5398.27% by weight	888.6070 lb/hr
CO_2	7.83% by weight	0.0002 lb/hr	0.0009 tpy	7.83% by weight	1.2895 lb/hr
TOC (Total)	351.00% by weight	0.0087 lb/hr	0.0383 tpy	351.00% by weight	57.7787 lb/hr
Methane	215.62% by weight	0.0054 lb/hr	0.0235 tpy	215.62% by weight	35.4927 lb/hr
Ethane	35.39% by weight	0.0009 lb/hr	0.0039 tpy	35.39% by weight	5.8251 lb/hr
VOC (Total)	100.00% by weight	0.0025 lb/hr	0.0109 tpy	100.00% by weight	16.4610 lb/hr
HAP (Total)	6.23% by weight	0.0002 lb/hr	0.0007 tpy	6.23% by weight	1.0253 lb/hr
Benzene	1.5063% by weight	3.75E-05 lb/hr	1.64E-04 tpy	1.5063% by weight	2.48E-01 lb/hr
Ethylbenzene	0.0477% by weight	1.19E-06 lb/hr	5.20E-06 tpy	0.0477% by weight	7.85E-03 lb/hr
Hexane (n-)	2.8866% by weight	7.18E-05 lb/hr	3.15E-04 tpy	2.8866% by weight	4.75E-01 lb/hr
Methanol					
Naphthalene					
Toluene	1.3668% by weight	3.40E-05 lb/hr	1.49E-04 tpy	1.3668% by weight	2.25E-01 lb/hr
Trimethylpentane (2,2,4-)	0.0139% by weight	3.45E-07 lb/hr	1.51E-06 tpy	0.0139% by weight	2.29E-03 lb/hr
Xylenes	0.4073% by weight	1.01E-05 lb/hr	4.44E-05 tpy	0.4073% by weight	6.71E-02 lb/hr

NOTES

1. Emissions calculated using methods provided in USEPA, AP-42 Section 5.2 dated 1/95. $L_L = 12.46[(S)M_VP/T]$
2. Physical property, throughput and speciation data based data from supply vessel emission calculation spreadsheet.

TABLE F-1I
Volatile Organic Liquids Loading (Tanker Trucks)
Hourly and Annual Emission Estimates

Source	WEYM-TL-OIL				
Supply Vessel	WEYM-TK-OIL1				
	Oil				
	570 gal			570 gal	
Tanker Truck Service	Dedicated Normal			Dedicated Normal	
Loading Method	Splash			Splash	
Saturation Factor	1.45 n.d.			1.45 n.d.	
Vapor Molecular Weight	130.00 lb/lb-mol			130.00 lb/lb-mol	
Bulk Liquid Temperature	59.64 °F			85.22 °F	
	519.64 R			545.22 R	
Vapor Pressure	0.0067 psia			0.0141 psia	
Loading Loss Factor	0.0302 lb/kgal			0.0607 lb/kgal	
Pumping Rate				150 gpm	
Throughput	12.00 turnover/yr				
	6,840 gal/yr			570 gal/hr	
Loading Losses	0.2066 lb/yr	Average	Maximum	0.0346 lb/hr	Maximum
Residual Liquid	100.00% by weight	0.00002 lb/hr	0.0001 tpy	100.00% by weight	0.0346 lb/hr
TOC (Total)	100.00% by weight	0.00002 lb/hr	0.0001 tpy	100.00% by weight	0.0346 lb/hr
Methane					
Ethane					
VOC (Total)	100.00% by weight	0.00002 lb/hr	0.0001 tpy	100.00% by weight	0.0346 lb/hr
HAP (Total)					
Benzene					
Ethylbenzene					
Hexane (n-)					
Methanol					
Naphthalene					
Toluene					
Trimethylpentane (2,2,4-)					
Xylenes					

NOTES

1. Emissions calculated using methods provided in USEPA, AP-42 Section 5.2 dated 1/95. $L_L = 12.46[(S)M_V P/T]$
2. Physical property, throughput and speciation data based data from supply vessel emission calculation spreadsheet.

TABLE F-1J
Volatile Organic Liquids Loading (Tanker Trucks)
Hourly and Annual Emission Estimates

Source	WEYM-TL-OW				
Supply Vessel	WEYM-TK-OW1				
	Oily Water				
	3,000 gal			3,000 gal	
Tanker Truck Service	Dedicated Normal			Dedicated Normal	
Loading Method	Splash			Splash	
Saturation Factor	1.45 n.d.			1.45 n.d.	
Vapor Molecular Weight	130.00 lb/lb-mol			130.00 lb/lb-mol	
Bulk Liquid Temperature	59.64 °F			85.22 °F	
	519.64 R			545.22 R	
Vapor Pressure	0.0067 psia			0.0141 psia	
Loading Loss Factor	0.0302 lb/kgal			0.0607 lb/kgal	
Pumping Rate				150 gpm	
Throughput	12.00 turnover/yr				
	36,000 gal/yr			3,000 gal/hr	
Loading Losses	1.0873 lb/yr	Average	Maximum	0.1821 lb/hr	Maximum
Residual Liquid	100.00% by weight	0.00012 lb/hr	0.0005 tpy	100.00% by weight	0.1821 lb/hr
TOC (Total)	100.00% by weight	0.00012 lb/hr	0.0005 tpy	100.00% by weight	0.1821 lb/hr
Methane					
Ethane					
VOC (Total)	100.00% by weight	0.00012 lb/hr	0.0005 tpy	100.00% by weight	0.1821 lb/hr
HAP (Total)					
Benzene					
Ethylbenzene					
Hexane (n-)					
Methanol					
Naphthalene					
Toluene					
Trimethylpentane (2,2,4-)					
Xylenes					

NOTES

1. Emissions calculated using methods provided in USEPA, AP-42 Section 5.2 dated 1/95. $L_L = 12.46[(S)M_V P/T]$
2. Physical property, throughput and speciation data based data from supply vessel emission calculation spreadsheet.

TABLE G-1B
Gas Releases
Hourly and Annual Emission Estimates

Category	Station Operations					
Source	WEYM-GR-ST			WEYM-GR-PL		
	Avg. Hourly	Max. Annual	Max. Hourly	Avg. Hourly	Max. Annual	Max. Hourly
Gas Release	811 scfh	7,100,000 scf/yr	20,000 scfh	0 scfh	0 scf/yr	0 scfh
	37 lb/hr	321,691 lb/yr	976 lb/hr	0 lb/hr	0 lb/yr	0 lb/hr
NO_X						
CO						
SO_2						
$PM_{10/2.5}$						
$CO_{2\text{-}e}$	876 lb/hr	3,836 tpy	23,619 lb/hr	0 lb/hr	0 tpy	0 lb/hr
CO_2	1.2511 lb/hr	5.4796 tpy	46.3880 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
N_2O						
TOC (Total)	37 lb/hr	161 tpy	976 lb/hr	0 lb/hr	0 tpy	0 lb/hr
Methane	35 lb/hr	153 tpy	943 lb/hr	0 lb/hr	0 tpy	0 lb/hr
Ethane	5 lb/hr	21 tpy	191 lb/hr	0 lb/hr	0 tpy	0 lb/hr
VOC (Total)	0.8072 lb/hr	3.5356 tpy	92.6585 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
VOC (non-HAP)	0.7825 lb/hr	3.4275 tpy	90.4818 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
HAP (Total)	0.0247 lb/hr	0.1080 tpy	2.1766 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
Acetaldehyde						
Acrolein						
Benzene	0.0067 lb/hr	0.0295 tpy	0.7786 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
Biphenyl						
Butadiene (1,3-)						
Carbon Tetrachloride						
Chlorobenzene						
Chloroform						
Dichloropropene (1,3-)						
Ethylbenzene	0.0030 lb/hr	0.0133 tpy	0.1200 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
Ethylene Dibromide						
Formaldehyde						
Hexane (n-)	0.0143 lb/hr	0.0627 tpy	2.1766 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
Methanol						
Methylene Chloride						
Methylnaphthalene (2-)						
Naphthalene						
PAH						
Phenol						
Propylene Oxide						
Styrene						
Tetrachloroethane (1,1,2,2-)						
Toluene	0.0076 lb/hr	0.0332 tpy	0.6757 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
Trichloroethane (1,1,2-)						
Trimethylpentane (2,2,4-)	0.0025 lb/hr	0.0111 tpy	0.0675 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
Vinyl Chloride						
Xylenes	0.0092 lb/hr	0.0403 tpy	1.0197 lb/hr	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr

NOTES

1. Gas release estimates based on engineering evaluation of several other compressor stations.
2. Data used in estimates is based upon model deemed to be most representative of natural gas at the site.
   There are five (5) models to choose from which are based on laboratory extended analysis of samples collected at various locations along Enbridge pipelines.
   Selected Grouping of Available Samples: **PLQNG** Samples that conform with Tariff
   Number of Samples in Grouping: 421
   States Represented in Grouping: AR, CT, IN, KY, LA, MA, MD, ME, MO, MS, NJ, NS, NY, OH, OK, PA, RI, TN, TX, VA and WV
   Dates Represented in Grouping: 2011 thru 2016
   Selected Class for Grouping: **WC** → Selected Model: **PLQNG: WC**
3. If necessary, customizations (SF) are applied to make the models more representative of natural gas at the site.

	Average	SF	Maximum	SF
Upper Percentile Limit Applied:	90%		100%	
Heating Value (BTU/scf)	1,069 BTU/scf	100%	1,109 BTU/scf	100%
Density (lb/scf) at USEPA Standard Conditions	0.0453 lb/scf	100%	0.0488 lb/scf	100%
VOC (Total)	2.20% by wt.	100%	9.50% by wt.	100%
HAP (Total)	0.07% by wt.	100%	0.22% by wt.	100%

TABLE H-1Ba
Piping Components
Hourly and Annual Emission Estimates

Source			WEYM-PC-NG			
Service			Gas			
			Natural Gas			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	526 components			
		Emission Factor	4.50E-03 kg/hr/component			
	Connectors	Count	2,030 components			
		Emission Factor	2.00E-04 kg/hr/component			
	Flanges	Count	352 components			
		Emission Factor	3.90E-04 kg/hr/component			
	Open-Ended Lines	Count	2 components			
		Emission Factor	2.00E-03 kg/hr/component			
	Pump Seals	Count	0 components			
		Emission Factor	2.40E-03 kg/hr/component			
	Other	Count	49 components	**Emissions**		
		Emission Factor	8.80E-03 kg/hr/component	**Avg. Hourly**	**Max. Annual**	**Max. Hourly**
Speciation	CO_{2-e}		2384.96% by weight	175.8999 lb/hr	770.4416 tpy	178.5537 lb/hr
	CO_2		3.41% by weight	0.2513 lb/hr	1.1005 tpy	0.3507 lb/hr
	TOC (Total)		100.00% by weight	7.3754 lb/hr	32.3042 tpy	7.3754 lb/hr
	Methane		95.262% by weight	7.0259 lb/hr	30.7736 tpy	7.1281 lb/hr
	Ethane		12.751% by weight	0.9404 lb/hr	4.1191 tpy	1.4428 lb/hr
	VOC (Total)		2.198% by weight	0.1621 lb/hr	0.7101 tpy	0.7005 lb/hr
	VOC (non-HAP)		2.131% by weight	0.1572 lb/hr	0.6884 tpy	0.6840 lb/hr
	HAP (Total)		0.067% by weight	0.0050 lb/hr	0.0217 tpy	0.0165 lb/hr
	Benzene		0.018% by weight	1.35E-03 lb/hr	5.93E-03 tpy	5.89E-03 lb/hr
	Ethylbenzene		0.008% by weight	6.08E-04 lb/hr	2.66E-03 tpy	9.07E-04 lb/hr
	Hexane (n-)		0.039% by weight	2.88E-03 lb/hr	1.26E-02 tpy	1.65E-02 lb/hr
	Methanol					
	Naphthalene					
	Toluene		0.021% by weight	1.52E-03 lb/hr	6.68E-03 tpy	5.11E-03 lb/hr
	Trimethylpentane (2,2,4-)		0.007% by weight	5.08E-04 lb/hr	2.22E-03 tpy	5.11E-04 lb/hr
	Xylenes		0.025% by weight	1.85E-03 lb/hr	8.09E-03 tpy	7.71E-03 lb/hr

NOTES

1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017).
The average SOCMI w/o ethylene emission factor is used for pumps in heavy oil service (Table 2-1) since an emission factor isn't provided in Table 2-4.
2. Piping component counts based on design drawings for a similar compressor station.
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.
4. Weight percents based on gas analysis used to estimate gas release annual emissions (TABLE G-1B).
Maximum hourly emissions are based on the worst-case short-term weight percents even though the values are NOT presented.

TABLE H-1Bb
Piping Components
Hourly and Annual Emission Estimates

Source			WEYM-PC-PL			
Service			Light Oil			
			Pipeline Liquids			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	75 components			
		Emission Factor	7.50E-05 kg/hr/component			
	Connectors	Count	557 components			
		Emission Factor	1.47E-04 kg/hr/component			
	Flanges	Count	115 components			
		Emission Factor	7.70E-05 kg/hr/component			
	Open-Ended Lines	Count	2 components			
		Emission Factor	4.20E-05 kg/hr/component			
	Pump Seals	Count	1 components			
		Emission Factor	3.25E-03 kg/hr/component			
	Other	Count	1 components	**Emissions**		
		Emission Factor	1.88E-03 kg/hr/component	**Avg. Hourly**	**Max. Annual**	**Max. Hourly**
Speciation	CO_{2-e}		0.96% by weight	0.0021 lb/hr	0.0094 tpy	0.0026 lb/hr
	CO_2		0.01% by weight	0.0000 lb/hr	0.0001 tpy	0.0000 lb/hr
	TOC (Total)		99.99% by weight	0.2239 lb/hr	0.9806 tpy	0.2687 lb/hr
	Methane		0.04% by weight	0.0001 lb/hr	0.0004 tpy	0.0001 lb/hr
	Ethane		0.09% by weight	0.0002 lb/hr	0.0009 tpy	0.0002 lb/hr
	VOC (Total)		99.86% by weight	0.2236 lb/hr	0.9794 tpy	0.2683 lb/hr
	VOC (non-HAP)		85.32% by weight	0.1910 lb/hr	0.8367 tpy	0.2292 lb/hr
	HAP (Total)		14.54% by weight	0.0326 lb/hr	0.1426 tpy	0.0391 lb/hr
	Benzene		1.44% by weight	3.23E-03 lb/hr	1.41E-02 tpy	3.87E-03 lb/hr
	Ethylbenzene		0.48% by weight	1.07E-03 lb/hr	4.67E-03 tpy	1.28E-03 lb/hr
	Hexane (n-)		1.69% by weight	3.79E-03 lb/hr	1.66E-02 tpy	4.55E-03 lb/hr
	Methanol					
	Naphthalene					
	Toluene		4.49% by weight	1.01E-02 lb/hr	4.40E-02 tpy	1.21E-02 lb/hr
	Trimethylpentane (2,2,4-)		0.03% by weight	5.78E-05 lb/hr	2.53E-04 tpy	6.94E-05 lb/hr
	Xylenes		6.42% by weight	1.44E-02 lb/hr	6.29E-02 tpy	1.72E-02 lb/hr

NOTES

1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017).
The average SOCMI w/o ethylene emission factor is used for pumps in heavy oil service (Table 2-1) since an emission factor isn't provided in Table 2-4.
2. Piping component counts based on design drawings for a similar compressor station.
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.
4. Weight percents based on composition estimate (TABLE F-1).
5. Maximum hourly emissions are based on 120% of the hourly emissions estimated in an effort to be conservative.

TABLE H-1Bc
Piping Components
Hourly and Annual Emission Estimates

Source			WEYM-PC-OIL			
Service			Heavy Oil			
			Oil			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	37 components			
		Emission Factor	8.40E-06 kg/hr/component			
	Connectors	Count	252 components			
		Emission Factor	7.50E-06 kg/hr/component			
	Flanges	Count	97 components			
		Emission Factor	3.90E-07 kg/hr/component			
	Open-Ended Lines	Count	0 components			
		Emission Factor	1.40E-04 kg/hr/component			
	Pump Seals	Count	6 components			
		Emission Factor	8.62E-03 kg/hr/component			
	Other	Count	2 components	**Emissions**		
		Emission Factor	3.20E-05 kg/hr/component	**Avg. Hourly**	**Max. Annual**	**Max. Hourly**
Speciation	$CO_{2\text{-}e}$					
	CO_2					
	TOC (Total)		100.00% by weight	0.1191 lb/hr	0.5216 tpy	0.1429 lb/hr
	Methane					
	Ethane					
	VOC (Total)		100.00% by weight	0.1191 lb/hr	0.5216 tpy	0.1429 lb/hr
	VOC (non-HAP)		100.00% by weight	0.1191 lb/hr	0.5216 tpy	0.1429 lb/hr
	HAP (Total)					
	Benzene					
	Ethylbenzene					
	Hexane (n-)					
	Methanol					
	Naphthalene					
	Toluene					
	Trimethylpentane (2,2,4-)					
	Xylenes					

NOTES

1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017).
The emission factor for pumps in heavy oil service is obtained from Table 2-1.
2. Piping component counts based on design drawings for a similar compressor station.
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.
4. Weight percents based listed on MSDS.
5. Maximum hourly emissions are based on 120% of the hourly emissions estimated in an effort to be conservative.

TABLE H-1Bd
Piping Components
Hourly and Annual Emission Estimates

Source			WEYM-PC-EC			
Service			Water/Oil			
			Coolant			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	0 components			
		Emission Factor	9.80E-05 kg/hr/component			
	Connectors	Count	0 components			
		Emission Factor	1.10E-04 kg/hr/component			
	Flanges	Count	0 components			
		Emission Factor	2.90E-06 kg/hr/component			
	Open-Ended Lines	Count	0 components			
		Emission Factor	2.50E-04 kg/hr/component			
	Pump Seals	Count	0 components			
		Emission Factor	2.40E-05 kg/hr/component			
	Other	Count	0 components	**Emissions**		
		Emission Factor	1.40E-02 kg/hr/component	**Avg. Hourly**	**Max. Annual**	**Max. Hourly**
Speciation	$CO_{2\text{-e}}$					
	CO_2					
	TOC (Total)		60.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	Methane					
	Ethane					
	VOC (Total)		60.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	VOC (non-HAP)					
	HAP (Total)		60.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	Benzene					
	Ethylbenzene					
	Hexane (n-)					
	Methanol					
	Naphthalene					
	Toluene					
	Trimethylpentane (2,2,4-)					
	Xylenes					

NOTES

1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017).
The average SOCMI w/o ethylene emission factor is used for pumps in heavy oil service (Table 2-1) since an emission factor isn't provided in Table 2-4.
2. Piping component counts based on design drawings for a similar compressor station.
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.
4. Weight percents based listed on MSDS.
5. Maximum hourly emissions are based on 120% of the hourly emissions estimated in an effort to be conservative.

TABLE H-1Be
Piping Components
Hourly and Annual Emission Estimates

Source			WEYM-PC-HF			
Service			Heavy Oil			
			Glycol			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	0 components			
		Emission Factor	8.40E-06 kg/hr/component			
	Connectors	Count	0 components			
		Emission Factor	7.50E-06 kg/hr/component			
	Flanges	Count	0 components			
		Emission Factor	3.90E-07 kg/hr/component			
	Open-Ended Lines	Count	0 components			
		Emission Factor	1.40E-04 kg/hr/component			
	Pump Seals	Count	0 components			
		Emission Factor	8.62E-03 kg/hr/component			
	Other	Count	0 components	**Emissions**		
		Emission Factor	3.20E-05 kg/hr/component	**Avg. Hourly**	**Max. Annual**	**Max. Hourly**
Speciation	CO_{2-e}					
	CO_2					
	TOC (Total)		100.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	Methane					
	Ethane					
	VOC (Total)		100.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	VOC (non-HAP)					
	HAP (Total)		100.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	Benzene					
	Ethylbenzene					
	Hexane (n-)					
	Methanol					
	Naphthalene					
	Toluene					
	Trimethylpentane (2,2,4-)					
	Xylenes					

NOTES

1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017).
The emission factor for pumps in heavy oil service is obtained from Table 2-1.
2. Piping component counts based on design drawings for a similar compressor station.
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.
4. Weight percents based listed on MSDS.
5. Maximum hourly emissions are based on 120% of the hourly emissions estimated in an effort to be conservative.

TABLE H-1Bf
Piping Components
Hourly and Annual Emission Estimates

Source			WEYM-PC-ME			
Service			Light Oil			
			Pipeline Liquids			
Minimum hours when component purged with inert gas			0 hrs/yr			
Component	Valves	Count	0 components			
		Emission Factor	2.50E-03 kg/hr/component			
	Connectors	Count	0 components			
		Emission Factor	2.10E-04 kg/hr/component			
	Flanges	Count	0 components			
		Emission Factor	1.10E-04 kg/hr/component			
	Open-Ended Lines	Count	0 components			
		Emission Factor	1.40E-03 kg/hr/component			
	Pump Seals	Count	0 components			
		Emission Factor	1.30E-02 kg/hr/component			
	Other	Count	0 components	**Emissions**		
		Emission Factor	7.50E-03 kg/hr/component	**Avg. Hourly**	**Max. Annual**	**Max. Hourly**
Speciation	CO_{2-e}					
	CO_2					
	TOC (Total)		100.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	Methane					
	Ethane					
	VOC (Total)		100.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	VOC (non-HAP)					
	HAP (Total)		100.00% by weight	0.0000 lb/hr	0.0000 tpy	0.0000 lb/hr
	Benzene					
	Ethylbenzene					
	Hexane (n-)					
	Methanol		100.00% by weight	0.00E+00 lb/hr	0.00E+00 tpy	0.00E+00 lb/hr
	Naphthalene					
	Toluene					
	Trimethylpentane (2,2,4-)					
	Xylenes					

NOTES

1. Emission factors obtained from Table 2-4 (Oil & Gas Production Operations) of Protocol for Equipment Leak Emission Estimates (EPA 453/R-95-017).
The average SOCMI w/o ethylene emission factor is used for pumps in heavy oil service (Table 2-1) since an emission factor isn't provided in Table 2-4.
2. Piping component counts based on design drawings for a similar compressor station.
3. The component type "Other" includes blowdown valves, relief valves, and compressor seals.
4. Weight percents based on composition estimate (TABLE F-1).
5. Maximum hourly emissions are based on 120% of the hourly emissions estimated in an effort to be conservative.

TABLE I-1
Parts Washer
Hourly and Annual Emission Estimates

Solvent			Eversol 143			
Solvent Density			6.84 lb/gal			
Potential Make-up Solvent Requirement	Hourly	Maximum	0.3288 gal/hr			
		Average	0.0137 gal/hr	**Emissions**		
	Annual		120.00 gal/yr	**Avg. Hourly**	**Max. Hourly**	**Max. Annual**
Speciation	TOC (Total)		100.00% by weight	0.0937 lb/hr	2.2484 lb/hr	0.4103 tpy
	Methane					
	Ethane					
	VOC (Total)		100.00% by weight	0.0937 lb/hr	2.2484 lb/hr	0.4103 tpy
	VOC (non-HAP)		100.00% by weight	0.0937 lb/hr	2.2484 lb/hr	0.4103 tpy
	HAP (Total)					
	Benzene					
	Ethylbenzene					
	Hexane (n-)					
	Naphthalene					
	Toluene					
	Trimethylpentane (2,2,4-)					
	Xylenes					

NOTES

1. Although emissions are estimated based on the physical properties and chemical speciation of Eversol 143, other solvents may be used as long as the represented solvent density and chemical species weight percents are not exceeded. MSDS indicate that the vapor pressure at 100°F is less than 5 mmHg (0.097 psia).
2. Potential maximum annual solvent make-up is based on past experience and a safety factor.
3. Potential maximum hourly solvent make-up is the potential maximum annual solvent make-up divided by 365 day/yr.
4. Potential average hourly solvent make-up is the potential maximum annual solvent make-up divided by 8,760 hrs/yr.

ATTACHMENT H: REDLINED DRAFT NON-MAJOR CPA FOR WEYMOUTH COMPRESSOR STATION

March 30, 2017

Mr. Thomas Wooden Jr.
Vice President, Field Operations
Algonquin Gas Transmission, LLC.
P.O. Box 1642
Houston, TX 77251-1642

RE: Weymouth
Transmittal No.: X266786
Application No.: SE-15-027
Class: SM-25
FMF No.: 571926
AIR QUALITY PROPOSED PLAN APPROVAL

Dear Mr. Wooden:

The Massachusetts Department of Environmental Protection ("MassDEP"), Bureau of Air and Waste, has reviewed your non-Major Comprehensive Plan Application ("Application") listed above. This Application concerns the proposed construction of a natural gas fired turbine at your proposed gas pipeline compressor station located at 50 Bridge Street in Weymouth, Massachusetts ("Facility"). The Application bears the seal and signature of David Cotter Massachusetts Registered Professional Engineer Number 49068.

This Application was submitted in accordance with 310 CMR 7.02 Plan Approval and Emission Limitations as contained in 310 CMR 7.00 "Air Pollution Control" regulations adopted by MassDEP pursuant to the authority granted by Massachusetts General Laws, Chapter 111, Section 142 A-N, Chapter 21C, Section 4 and 6, and Chapter 21E, Section 6. MassDEP's review of your Application has been limited to air pollution control regulation compliance and does not relieve you of the obligation to comply with any other regulatory requirements.

In response to a public petition, accompanied by over one hundred (100) signatures, this Proposed Plan Approval has been made subject to a 30-day public comment period. All comments received will be considered and addressed, as appropriate, before taking a final action on the Plan Application.

MassDEP has determined that the Application is administratively and technically complete and that the Application is in conformance with the Air Pollution Control regulations and current air pollution control engineering practice, and hereby **Proposes** to grant this **Plan Approval** for said Application, as submitted, subject to the conditions listed below.

Please review the entire Proposed Plan Approval, as it stipulates the conditions with which the Facility owner/operator ("Permittee") must comply in order for the Facility to be operated in compliance with this Proposed Plan Approval.

1. DESCRIPTION OF FACILITY AND APPLICATION

A. PROJECT DESCRIPTION

Algonquin Gas Transmission, LLC. ("Algonquin") has proposed the installation and operation of a new natural gas compressor station. This compressor station will support the capacity upgrades and expansion of Algonquin's natural gas transmission pipeline system, which runs from Mahwah, New Jersey to Beverly, Massachusetts for further transportation and deliveries on the Maritimes & Northeast Pipeline, LLC system. Collectively, this project is referred to as the Atlantic Bridge Project.

B. FACILITY and EQUIPMENT DESCRIPTION

The Facility will be on a 15.9± acre site bounded by Route 3A (Bridge St.), Calpine Fore River Energy Center, and the Fore River. The Facility includes an existing gas metering and regulation ("M&R") station.

The proposed natural gas compressor will be driven by one (1) Solar Taurus 60-7802 natural gas fired stationary combustion turbine. The turbine will fire pipeline natural gas as the exclusive fuel. The turbine will have a nominal heat input rating of 61.29 million British thermal units per hour ("MMBtu/hr"), lower heating value ("LHV"); and a nominal power output of 7,700 horsepower ("hp"), which is approximately 5.74 MW.[1] The turbine will have a maximum energy input rating of 74.91 MMBtu/hr, higher heating value ("HHV"); a maximum fuel rate of 73,444 standard cubic feet ("scf") per hour; and a maximum power output of 8,664 hp, which is approximately 6.46 megawatts ("MW").[2]

Exhaust gases from the proposed turbine will be emitted through a stack with an equivalent inside diameter of approximately 9 feet, which provides a nominal exit velocity of 28 feet per second at a nominal temperature of 999 °F. The top of the steel stack will be at least 60 feet above ground level.

The proposed turbine uses dry low NOx technology, operating under the brand name "SoLoNOx," which will limit nitrogen oxide ("NOx") emissions to 9 parts per million by volume, dry basis ("ppmvd") at 15 percent (%) oxygen ("O_2") while operating at ambient temperatures above 0 °F. The turbine will be equipped with an oxidation catalyst, which will reduce emissions of carbon monoxide ("CO") and volatile organic compounds ("VOC") by 95% and 50%, respectively. Emissions will not exceed 1.25 ppmvd at 15% O_2 for CO and 2.4 ppmvd

---

[1] At ISO conditions.
[2] At -20 degrees Fahrenheit.

at 15% O_2 for VOCs. All emissions factors, which are provided by the manufacturer, have been established as BACT. All emission rates are guaranteed by the manufacturer during steady-state operation at 50% – 100% load for all ambient temperatures above 0 °F.

The turbine has an efficiency rating of 35.7%, which is among the most efficient in its class. Turbine efficiency is the primary means to minimize emissions of carbon dioxide (CO_2).

Annual and short-term monthly emission limitations from the turbine are based on combined emissions from normal operations at an average annual ambient temperature of 46.65°F[3], start-up/shutdown, low temperature operation occurring within a temperature range of -20°F and 0°F, and transient events[4]. At low ambient temperatures (i.e. below 0 °F), emissions of NOx, CO, and VOCs will increase. During periods of low temperature, the emissions will be based on the emission factors provided by the manufacturer, which are listed in Table 8B of the Plan Approval. Transient events will be limited to 25 hours per month and 50 hours per consecutive 12-month period. Transient event emissions will be based on the emission factors provided by the manufacturer, which are listed in Table 8C of the Plan Approval.

The turbine's startup sequence takes approximately 9 minutes from the initial firing to steady-state operation. This includes 3 minutes of ignition-idle operation and 6 minutes of loading / thermal stabilization. During the startup sequence, it is assumed that the oxidation catalyst will not have reached its minimum effective operating temperature and as such, will not have a measurable destruction efficiency. Shutdown of the turbine takes approximately 8.5 minutes for loading and thermal stabilization, during which the oxidation catalyst will be at the required temperature to achieve the specified control efficiencies for CO and VOCs. Startup and shutdown emissions, which are supplied by the manufacturer, are listed in Table 8D of this Proposed Plan Approval.

As previously indicated, all emission rates are guaranteed by the manufacturer during steady-state operation at 50% – 100% load for all ambient temperatures above 0 °F. When the turbine is operating outside of those conditions (i.e., during transient, startup, shutdown, or low temperature events), the turbine monitoring system will indicate SoLoNOx is inactive.

The Facility will include one new natural gas-fired 585 brake horsepower Waukesha model VGF24GL emergency spark ignition engine generator set. This engine will be subject to requirements of MassDEP's Industry Performance Standards for Engines and Combustion Turbines at 310 CMR 7.26(40) through (44). MassDEP Air Quality regulations at 310 CMR 7.26(42)(e) "Emission Certification, Monitoring and Testing," requires certification under the "Environmental Results Program" at 310 CMR 70.00. Certification shall include a statement from the supplier that the installed engine is capable of complying with the emission limitations for the first three years of operation. A one-time certification is required to be made to MassDEP within 60 days of commencement of operation.

---

[3] USEPA TANKS 4.09d program for Worcester, MA (worst case of Worcester, Boston, and Providence, RI).
[4] Transient events are periods of time when the turbine is operating outside of steady state or at less than 50% load, excluding startup, shutdown, or low temperature events.

Fugitive emissions occur at piping components such as pump seals, valves, pipe fittings, and the compressor. Emissions were calculated based on the methodology and emission factors contained in EPA publication AP-42 (EPA/R-95-017). Fugitive emissions from piping components will be minimized through the implementation of a Leak Detection and Repair (LDAR) program. LDAR is a work practice designed to identify leaking equipment so that emissions can be reduced through repairs. Monitoring, at regular intervals, will identify leaking components so repairs can be made within the required timeframe. The LDAR Program will use the monitoring and testing methodology that is no less stringent than the LDAR requirements in 40 CFR 60, Subpart OOOOa: Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.

Additional gas releases associated with the compressor operation occur at the Facility. These routine and non-routine releases are from compressor start-up / shutdown and from maintenance activities.

1. Routine operations, including startup and shutdown of the compressor, result in emissions from the following activities:
   - Case venting related to shutdown of the compressor, except in the case of pressurized holds. When the compressor is taken offline, isolation valves on the inlet and outlet gas lines of the compressor are closed. The pressurized gas remaining in the compressor and associated piping is vented;
   - Gas seal leakage during normal operation and standby shutdown (i.e., compressor seal leakage). Depending on the operating mode of the compressor and the length of time the unit may be in standby mode, the compressor may remain under pressure. If the compressor is in standby mode for a sufficient length of time, compressor seal leakage will result in emissions;
   - Air purges related to startup of the compressor following a depressurization of the unit. Equipment is purged of air and the system is pressurized prior to startup; and
   - Other ancillary activities, including releases from gas-operated pneumatic equipment.

2. Maintenance activities, including startup and shutdown of the compressor, result in emissions from the following activities:
   - Station blowdowns for purposes of major maintenance;
   - Case venting related to shutdown of the compressor for purposes of maintenance;
   - Air purges related to startup of the compressor following a depressurization of the unit. Equipment is purged of air and the system is pressurized prior to startup;
   - Liquid purges related to moving liquids through the pipeline liquids system; and
   - Other ancillary activities, including fuel line venting and air purging for ancillary equipment, such as emergency generators, and fuel gas heaters, and valve seat leakage.

3. Pipeline blowdowns.

- Venting of the pipeline section for maintenance purposes.

Incoming gas will be cleaned and any residual moisture will be removed. This collected water will be stored in a condensate storage tank and periodically transported off site. The associated piping and equipment will be included in the aforementioned Leak Detection and Repair program.

Equipment Exempt from Plan Approval

The following ancillary equipment is exempt from plan approval:

Table 1	
Equipment Description	**Basis for exemption**
Natural gas fired turbine fuel gas heater Heat input rating 0.23 MMBtu/hr	310 CMR 7.02(2)(b)15.a.
5 catalytic space heaters Heat input rating 0.072 MMBtu/ hr each	310 CMR 7.02(2)(b)15.a.
Cold degreaser	310 CMR 7.03(8), which requires operation in a manner consistent with 310 CMR 7.18(8).
Waukesha model VGF24GL emergency engine generator set	310 CMR 7.26(40) through (44)
Separator vessels (4 units)	310 CMR 7.02(2)(b)11.
Condensate storage tank	310 CMR 7.02(2)(b)11.
Lubricating oil storage tank	310 CMR 7.02(2)(b)11.
Oily water storage tank	310 CMR 7.02(2)(b)11.
Hanover natural gas-fired heater [1] 9.5 MMBtu/hr	310 CMR 7.02(2)(b)15.a.
NATCO natural gas-fired heater [1] 6.8 MMBtu/hr	310 CMR 7.02(2)(b)15.a.
Lochinvar natural gas-fired boilers (3 units)[1] 1.8 MMBtu/hr, each	310 CMR 7.02(2)(b)15.a.

Table 1 Notes:
1. The Hanover gas fired heater, the NATCO gas-fired heater, and the 3 Lochinvar gas-fired boilers are existing equipment associated with the metering and regulation station.

Table 1 Key:

CMR = Code of Massachusetts Regulations

MMBtu/hr = million British Thermal Units per hour

Sound Impacts and Mitigation

Operation of the Facility will create several sources of sound, which will be mitigated as follows: 1. Insulated / acoustically treated building housing the turbine and compressor, 2. use of a sound suppressant muffler on the turbine exhaust, 3. acoustical pipe insulation for outdoor above ground piping, 4. a silencer for the turbine air intake system, 5. low-noise lube oil coolers, 6. a low-noise gas cooler, and 7. a blowdown silencer.

The Facility is designed to meet the Federal Energy Regulatory Commission (“FERC”) standards for air and noise quality, which limits noise attributable to any new compressor station to an average day-night sound level of 55 decibels A weighted (“dB(A)”) at any pre-existing noise sensitive area (“NSA”)[5].

A sound analysis[6], which was included with the Air Plan Application, evaluated sound impacts at nine NSA’s as follows:

- NSA #1; Residences located on the North Side of Bridge Street, in Weymouth, approximately 610 feet south-southeast of the Station site “acoustic center” (i.e., anticipated location of Compressor Building);
- NSA #2; Residences at the end of Saint German St. (area of Germantown Point; Town of Quincy), approximately 1,370 feet north of the Station site center;
- NSA #3; Residences located along Kings Cove Beach Road (near Hunt Hills Point, Weymouth), approximately 1,560 feet east of the Station site center;
- NSA #4; Residences located near the intersection of Monatiquot Street and Vaness Road (Weymouth), approximately 900 feet south of the Station site center;
- NSA #5; Residences located along Kings Cove Way (Weymouth), approximately 1,030 feet southeast (SE) of the Station site center;
- NSA #6; Residences located in the area of Roslind Road and Evans Road (Weymouth), approximately 2,300 feet SE of the Station site center;
- NSA #7; Residences located in the area of Weybosset Street and Fore River Ave. (Weymouth), approximately 1,970 feet east-northeast (ENE) of the Station site center;
- NSA #8; Residences located along Dee Road (Quincy), approximately 2,400 feet west of the Station site center; and
- NSA #9; Johnson School (Pearl Street, Weymouth), located approximately 4,200 feet east-southeast (ESE) of the Station site center.

[5] 18 CFR 380.12(k)(4)(v)(A). A NSA as defined therein includes schools, hospitals, and residences.
[6] Hoover & Keith, Inc., *Weymouth Compressor Station Results of Additional Ambient Sound Survey and Updated Acoustical Analysis of a New Natural Gas Compressor Station Associated with the Proposed Atlantic Bridge Project*, dated January 11, 2017.

MassDEP's Noise Policy limits the maximum sound impacts attributable to a noise source to an increase in the broadband sound level of no more than 10 dB(A) above ambient. The sound impact analysis indicates that the Facility will not cause an increase in sound in excess of the sound impacts allowed by MassDEP's Noise Policy. The results of the sound impact analysis are as follows:

Table 2

Identified Receptor	Distance & Direction of Receptor/NSA	Measured Ambient Nighttime L90 (dBA)	Calculated Sound Level of Station [dB(A)]	Calculated Station Level + Lowest Ambient Level [dB(A)]	Increase above Lowest Ambient Level [dB(A)]
NSA 1	610 feet (SSE)	44.8	42.6	46.9	2.1
NSA 2	1,370 feet (north)	46.8	35.7	47.1	0.3
NSA 3	1,560 feet (east)	44.0	34.4	44.4	0.4
NSA 4	900 feet (south)	48.5	38.9	48.9	0.4
NSA 5	1,030 feet (SE)	41.3	37.5	42.8	1.5
NSA 6	2,300 feet (SE)	41.4	29.3	41.7	0.3
NSA 7	1,970 feet (ENE)	39.3	31.8	40.0	0.7
NSA 8	2,400 feet (west)	44.5	28.9	44.6	0.1
NSA 9	4,200 feet (ESE)	41.0	22.7	41.1	0.1

Table 2 Key:

ENE = east northeast
ESE = east southeast
SE = southeast
SSE = south southeast
dB(A) = decibels, A weighted
NSA = noise sensitive area

In addition, the sound impact analysis indicates the sound contribution at the closest station property line, which is the east station property line shared with the King's Cove Parcel, will not exceed the MassDEP Noise Policy.

MassDEP's Noise Policy also prohibits a "pure tone" condition, which is defined as when any octave band center frequency sound pressure level exceeds the two adjacent center frequency sound pressure levels by 3 decibels or more. A review of the sound analysis and associated supplemental forms submitted with the Application indicate operation of the Facility will not create a pure tone condition.

Accordingly, the predicted sound impacts generated by the Facility will meet the requirements of MassDEP's Noise Policy. A post-construction compliance demonstration for sound impacts is required herein.

C. EMISSIONS MODELING

An air dispersion modeling analysis[7] was conducted to demonstrate that the project's ambient air impacts, combined with the pre-existing background levels, will not cause or contribute to a violation of the National Ambient Air Quality Standards ("NAAQS"). The primary standards are health based standards established under the United States Clean Air Act ("CAA") that are designed to preserve public health and protect sensitive subpopulations, which include people with diseases (e.g. asthma, cardiovascular disease), children, and the elderly with an adequate margin of safety. The Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings

EPA has established Significant Impact Levels ("SILs"), which are numerical values that are used to evaluate the impact that a proposed source may have on the NAAQS (72 CFR 54.138). The SIL is the level of ambient impact below which the EPA considers a source to have an insignificant impact on air quality (72 CFR 54.130). The SILS are a small fraction of the NAAQS and ambient impacts below the SIL are commonly referred to as "de minimis." If the modeling shows that: (1) the predicted impact of a pollutant is less than the SIL, and (2) the difference between the background ambient air concentration and the NAAQS for that pollutant is greater than the SIL, the predicted impact of that pollutant is deemed insignificant. In these circumstances, MassDEP follows EPA Guidance and concludes that the emissions of that pollutant do not cause or contribute to a violation of the NAAQS without requiring cumulative impact modeling.

Table 3

Comparison of Maximum Predicted Impacts with Significant Impact Levels

Pollutant	Averaging Period	Max Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)	Below SIL
NO_2	1-Hour	**14.4**	7.5	**no**
	Annual	**2.0**	1	**no**
SO_2	1-Hour	6.5	7.8	yes
	3-Hour	6.3	25	yes
	24-Hour	**5.5**	5	**no**
	Annual	0.8	1	yes
PM_{10}	24-Hour	2.6	5	yes
$PM_{2.5}$	24-Hour	**2.3**	1.2	**no**
	Annual	**0.35**	0.3	**no**
CO	1-Hour	122.8	2,000	yes
	8-Hour	101.0	500	yes

[7] Trinity Consultants, *Air Dispersion Modeling Report, Algonquin Gas Transmission, LLC., Weymouth Compressor Station*, dated September 2016.

Table 3 Key:

CO = Carbon Monoxide
NO_2 = Nitrogen Dioxide
PM_{10} = Particulate Matter ≤ 10 microns in diameter
$PM_{2.5}$ = Particulate Matter ≤ 2.5 microns in diameter
SO_2 = Sulfur Dioxide
SIL = significant impact level
μg/m^3 = micrograms per cubic meter

Since the predicted impacts of SO_2 (1-hour, 3-hour, and annual averaging periods), PM_{10}, and CO are below the SIL, no additional modeling was performed. The predicted impacts of NO_2, $PM_{2.5}$, and SO_2 (24-hour averaging period) exceed the SIL, so a cumulative impact analysis was performed.

In evaluating cumulative impacts with respect to the NAAQS, maximum modeled impacts were added to representative ambient background concentrations and compared to the applicable NAAQS. The Applicant used background data obtained from MassDEP's existing monitoring station on Harrison Avenue in Roxbury and on Von Hillern St. in Boston. The background data, when added to the modeled impacts found that the maximum impacts from emissions from the proposed facility will be below the NAAQS, as indicated below:

Table 4

Comparison of Predicted Impact Concentrations with NAAQS

Pollutant	Averaging Period	Cumulative Impact of Weymouth Station and Regional Sources (μg/m^3)	Measured Background (μg/m^3)	Background plus Compressor Station Total Impact (μg/m^3)	NAAQS (μg/m^3)	Background plus Compressor Station % of NAAQS
NO_2	1-Hour	81.41	94.63	176.04	188	93.6%
	Annual	8.52	32.88	41.40	100	41.4%
SO_2	24-Hour	18.41	13.40	31.81	365	8.7%
$PM_{2.5}$	24-Hour	7.13	15.3	22.43	35	64.1%
	Annual	1.47	6.5	7.97	12	66.4%

Table 4 Key:

NAAQS = National Ambient Air Quality Standards
NO_2 = Nitrogen Dioxide
SO_2 = Sulfur Dioxide
μg/m^3 = micrograms per cubic meter
PM = Particulate Matter
$PM_{2.5}$ = Particulate Matter ≤ 2.5 microns in diameter
% = percent

The air dispersion modeling analysis also included an evaluation of the Facility's impacts relative to the MassDEP's 24-hour Threshold Effect Exposure Limits ("TELs") and annual Allowable Ambient Limits ("AALs") Guideline values for air toxics. The AALs and TELs were evaluated from Facility-wide sources at both 50% and 100% turbine load.

Table 5

Pollutant	TEL (24-hour)			AAL (annual)		
	TEL Limit (µg/m³)	Modeled concentration (µg/m³)	percent of limit[1]	AAL Limit (µg/m³)	Modeled concentration (µg/m³)	percent of limit[1]
Acetaldehyde	30	6.01E-02	0.2	0.40	8.04E-03	2.0
Acrolein	0.07	3.71E-02	53.0	0.07	4.94E-03	7.1
Benzene	0.6	2.17E-01	36.2	0.1	4.27E-02	42.7
1,3 Butadiene	1.20	1.93E-03	0.2	0.003	2.60E-04	8.7
Carbon tetrachloride	85.52	2.60E-04	0.0	0.07	4.00E-05	0.1
Chlorobenzene	93.88	2.20E-04	0.0	6.26	3.00E-05	0.0
Chloroform	132.76	2.10E-04	0.0	0.04	3.00E-05	0.1
Dichloromethane	100.00	1.40E-04	0.0	60.00	2.00E-05	0.0
Diphenyl	0.34	1.53E-03	0.5	0.09	2.00E-04	0.2
Ethylbenzene	300	7.87E-01	0.0	300	1.55E-02	0.0
Formaldehyde	2.00	3.86E-01	19.3	0.08	5.56E-02	69.5
Methanol	7.13	1.80E-02	0.3	7.13	2.39E-03	0.0
2-Methylnaphthalene	14.25	2.40E-04	0.0	14.25	3.00E-05	0.0
Naphthalene	14.25	2.91E-03	0.0	14.25	3.70E-04	0.0
Phenol	52.33	1.70E-04	0.0	52.33	2.00E-05	0.0
Propylene oxide	6.00	6.37E-02	1.1	0.30	6.43E-03	2.1
Styrene	200	1.70E-04	0.0	2	2.00E-05	0.0
1,1,2,2 Tetrachloroethane	18.67	3.10E-04	0.0	0.02	4.00E-05	0.2
Toluene	80	5.60E-01	0.7	20	1.11E-01	0.6
1,1,2 Trichloroethane	14.84	2.30E-04	0.0	0.06	3.00E-05	0.1
Vinyl chloride	3.47	1.10E-04	0.0	0.38	1.00E-05	0.0
xylenes	11.8	7.86E-01	6.7	11.8	1.54E-01	1.3

Table 5 Notes:
1. – Modeled concentration as a percent of limit.

Table 5 Key:

AAL = Ambient Air Limit
TEL = Threshold Effect Exposure Limit
µg/m³ = micrograms per cubic meter

Based upon a review of the modeling analysis contained in the application, maximum impacts from emissions from the proposed facility will be below the AALs/TELs.

D. REGULATORY APPLICABILITY

The Permittee has indicated that the Facility, emission units therein, or exempt equipment are subject to and will comply with the EPA's New Source Performance Standards ("NSPS") and National Emissions Standards for Hazardous Air Pollutants ("NESHAPs") and MassDEP's Industry Performance Standards, as follows:

Table 6

Affected Unit	Applicable Regulation	Title
Combustion turbine	40 CFR part 60 subpart KKKK	Standards of Performance for Stationary Combustion Turbines
Compressor station	40 CFR part 60 subpart OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015
Emergency engine [1]	310 CMR 7.26(40)-(42) and (44)	Industry Performance Standards – Engines and Combustion Turbines
	40 CFR part 60 subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
	40 CFR part 63 subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Table 6 Notes:
1. The emergency engine is exempt from plan approval; refer to Table 1 of this document for basis.

Table 6 Key:

CFR = Code of Federal Regulations CMR = Code of Massachusetts Regulations

The Permittee is advised that MassDEP has not accepted delegation for 40 CFR part 60 subpart JJJJ, subpart KKKK, or subpart OOOOa, or 40 CFR part 63 subpart ZZZZ. The Permittee is advised to consult with the EPA regarding the requirements of the NSPS and NESHAPs.

E. ENVIRONMENTAL JUSTICE

On January 30, 2017, the Massachusetts Executive Office of Energy and Environmental Affairs (EEA) adopted an updated Environmental Justice Policy ("EJ Policy") that requires MassDEP to make environmental justice an integral consideration in the implementation and enforcement of laws, regulations, and policies. The enhanced public participation / enhanced analysis requirements of the EJ Policy apply when the project / project site meet both thresholds:

(1) Any project that exceeds an Environmental Notification Form ("ENF") / Environmental Impact Report ("EIR") threshold for air, solid and hazardous waste (other than remediation projects), or wastewater and sewage sludge treatment and disposal; and

(2) The project site is located within one mile of an EJ Population (or in the case of projects exceeding an ENF / EIR threshold for air, within five miles of an EJ Population).

The EEA Geographic Information System includes environmental justice areas divided by block groups based on the 2010 US Census data. Based on environmental justice mapping completed by EEA, the Facility is within 5 miles of a number of environmental justice communities in the Towns of Weymouth, Braintree, Quincy, Randolph, and the City of Boston.

This Project does not exceed the ENF / EIR requirements at 301 CMR 11.00, therefore, the updated Environmental Justice Policy dated January 30, 2017 is not applicable.

2. EMISSION UNIT IDENTIFICATION

Each Emission Unit ("EU") identified in Table 7 is subject to and regulated by this Proposed Plan Approval:

Table 7

EU	Description	Design Capacity	Pollution Control Device (PCD)
1	Solar Taurus 60 natural gas fired compressor turbine	7,700 hp / 5.74 MW (nominal) [1] 8,664 hp / 6.46 MW (peak) [2]	Oxidation catalyst
2	Venting (gas releases)	Not applicable	none
3	Piping components	Not applicable	LDAR program

Table 7 Notes:
1. At ISO conditions.
2. At -20 degrees Fahrenheit.

Table 7 Key:

EU = Emission Unit Number
hp = horsepower
ISO = International Organization for Standardization
LDAR = Leak Detection and Repair
MW = megawatts (mechanical)
PCD = Pollution Control Device

3. APPLICABLE REQUIREMENTS

A. OPERATIONAL, PRODUCTION and EMISSION LIMITS

The Permittee is subject to, and shall not exceed the Operational, Production, and Emission Limits as contained in Table 8A, 8B, 8C, and 8D:

Table 8A
Standard Operating Conditions

EU	Operational / Production Limit	Air Contaminant	Emission Limit [1, 2, 3]
1	1. 54.64 MMscf natural gas per month 2. 592.23 MMscf natural gas per consecutive 12-month period 3. Natural gas shall be the exclusive fuel of use	NOx	9 ppmvd at 15% O_2 0.94 tpm 10.03 tpy
	4. Minimum temperature at inlet of catalyst bed ≥ 880°F (hourly average basis) 5. Minimum pressure drop across the catalyst bed ≥ 2.83 in. W.C. (hourly average basis)	CO	1.25 ppmvd at 15% O_2 2.18 tpm 17.28 tpy
		VOC	2.4 ppmvd @ 15% O_2 0.30 tpm 2.64 tpy
		HAP (single)	0.05 tpm 0.42 tpy
		HAP (total)	0.1 tpm 0.80 tpy
	6. None	SO_2	14.29 lb/MMscf (HHV) 0.37 tpm 4.23 tpy
	7. None	PM PM_{10} $PM_{2.5}$	0.0066 lb/MMBtu (HHV) 0.18 tpm 1.99 tpy
	8. None	Opacity	Less than 5%, except 5% to less than 10% for up to 2 minutes during any one hour
2	9. Monthly emissions established in accordance with equation 1 10. Annual emissions established in accordance with equation 2	VOC	3.19 tpm 3.54 tpy
		HAP (single)	0.05 tpm 0.06 tpy
		HAP (total)	0.10 tpm 0.11 tpy

Equation 1:

$$m_{Pollutant_{month}} = Q_{Gas_{month}} \rho_{Gas_{monthly\ average}} wt\%_{Pollutant_{monthly\ average}}$$

Equation 2:

$$m_{Pollutant_{consecutive\ 12-month\ period}} = \sum_{month=1}^{\substack{consecutive \\ 12-month\ period}} m_{Pollutant_{month}}$$

m =	mass of pollutant, in pounds	*wt*% =	weight percent of pollutant in natural gas
Q =	quantity of natural gas in standard cubic feet	ρ =	density of natural gas in pound per standard cubic feet

Table 8B **Low Temperature Operation [4]**			
EU	**Air Contaminant**	**Emission Limit**	
		0°F ≥ Temp ≥ -20°F	Temp ≤ -20°F
1	NOx	11.36 lb/hr	32.46 lb/hr
	CO	0.82 lb/hr	1.24 lb/hr
	VOC	0.52 lb/hr	0.77 lb/hr
	PM/ PM_{10} / $PM_{2.5}$	0.49 lb/hr	0.49 lb/hr
	SO_2	1.05 lb/hr	1.05 lb/hr

Table 8C **Transient Events [5,8]**			
EU	**Operational / Production Limit**	**Air Contaminant**	**Emission Limit**
1	1. Operations during transient events (operation with SoLoNOx inactive, not including startup, shutdown, or low temperature events), not to exceed 25 hours per month and 50 hours in any consecutive 12-month period	NOx	32.46 lb/hr
		CO	1.24 lb/hr
		VOC	0.77 lb/hr

Table 8D
Startup / Shutdown Emissions [6]

EU	Operational / Production Limit	Air Contaminant	Startup	Shutdown [6]
1	1. Operation during startups (from first combustion of fuel to when SoLoNOx is active, but not to exceed 30 minutes) 2. Operation during shutdowns (from when SoLoNOx is inactive to flame out, but not to exceed 30 minutes)	NOx	0.80 lb/event	0.93 lb/event
	3. Operation during startups (from first combustion of fuel to when the temperature at the inlet to the catalyst bed reaches at least 880 °F, but not to exceed 30 minutes) 4. Operation during shutdowns (from initial	CO	77.24 lb/event	4.23 lb/event
		VOC	5.40 lb/event	2.62 lb/event

Table 8D Startup / Shutdown Emissions [6]				
EU	**Operational / Production Limit**	**Air Contaminant**	**Startup**	**Shutdown [6]**
	lowering of turbine fuel combustion rate with the intent to cease operation to flame out, but not to exceed 30 minutes)			

Table 8A, 8B, 8C, and 8D Key:

CMR = Code of Massachusetts Regulations
CO = Carbon Monoxide
EU = Emission Unit Number
°F = degrees Fahrenheit
HAP (single) = maximum single Hazardous Air Pollutant
HAP (total) = total Hazardous Air Pollutants
HHV = higher heating value
in WC= inches water column
lb = pounds
lb/event = pounds per event
lb/hr = pounds per hour
lb/MMBtu = lbs per million British Thermal Units
lb/MWh = pounds per megawatt hour
LDAR = Leak detection and repair
MMBtu million British Thermal Units
MMscf = million standard cubic feet
NO_x = Nitrogen Oxides
O_2 = oxygen
PM = Particulate Matter
$PM_{2.5}$ = Particulate Matter ≤ 2.5 microns in diameter
PM_{10} = Particulate Matter ≤ 10 microns in diameter
ppmvd = parts per million by volume, dry basis
Scf = standard cubic feet
SO_2 = Sulfur Dioxide
Temp = temperature
TPM = tons per month
TPY = tons per consecutive12-month period
VOC = Volatile Organic Compounds
≥ greater than or equal to
≤ less than or equal to

Table 8A, 8B, 8C, and 8D Notes:

1. Short-term monthly turbine emission limits are combined emissions based on normal operation at an average annual ambient temperature of 46.65°F, start-up/shutdown, low temperature operation during a temperature range of -20°F to 0°F, and transient events.
2. Annual turbine emissions are combined emissions based on normal operation at an average annual ambient temperature of 46.65°F, start-up/shutdown, low temperature operation during a temperature range of -20°F to 0°F, and transient events.
3. Compliance with the emission limits based on the applicable USEPA reference test method.
4. Turbine emissions associated with low temperature operation are to be included when determining monthly and annual emissions.

5. Turbine emissions associated with transient events are to be included when determining monthly and annual emissions.
6. Turbine emissions associated with startups and shutdowns are to be included when determining monthly and annual emissions.
7. The shutdown emission limits for VOC and CO are based on the oxidation catalyst being operational.
8. Transient events are periods of operation when the turbine is operating outside of steady state or when operating at less than 50% load excluding startup, shutdown and low temperature events.

B. COMPLIANCE DEMONSTRATION

The Permittee is subject to, and shall comply with, the monitoring, testing, record keeping, and reporting requirements as contained in Tables 9, 10, and 11:

Table 9

EU	Monitoring and Testing Requirements
1	1. The Permittee shall continuously monitor the turbine inlet temperature at all times that the turbine is operated.
	2. The Permittee shall continuously monitor the quantity of natural gas combusted in the turbine.
	3. The Permittee shall continuously monitor: a. the temperature at the inlet of oxidation catalyst bed, b. the pressure drop across the catalyst bed.
	4. The Permittee shall monitor the number of startups and shutdowns of the turbine and the duration of each event.
	5. The Permittee shall monitor the number of transient events and the duration of each event, as indicated by SoLoNOx inactive status, not including startup, shutdown, and low temperature events, which are monitored separately.
	6. Within 60 days of achieving maximum production rate, but no later than 180 days of startup, the Permittee shall conduct initial compliance testing for the emission unit. The testing shall be conducted on a date mutually agreed upon with MassDEP. Testing shall be conducted for NOx, CO, VOC, and $PM_{2.5}$ to determine the compliance status with the ppmvd, lb/MMBtu and lb/hr for standard operating conditions as listed in Table 8A. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. The Permittee shall conduct subsequent testing every two (2) years from the date of the initial compliance test.
	7. In order to demonstrate compliance with the applicable fuel sulfur requirement, the Permittee will utilize a current, valid purchase contract, tariff sheet or transportation contract for natural gas that will specify the maximum total sulfur content of the natural gas used at the facility.

Table 9	
EU	**Monitoring and Testing Requirements**
2	8. The Permittee shall monitor the date, time, duration, and quantity of gas released for each gas release event.
3	9. The Permittee shall monitor the piping components in accordance with the LDAR program. Refer to Special Terms and Condition, Table 12, Condition 4-6.
Facility-wide	10. The Permittee shall monitor all operations to ensure sufficient information is available to comply with 310 CMR 7.12 Source Registration.
	11. If and when MassDEP requires it, the Permittee shall conduct emission testing in accordance with USEPA Reference Test Methods and Regulation 310 CMR 7.13.
	12. At least 30 days prior to emission testing, the Permittee shall submit to MassDEP for approval, a stack emission pretest protocol.
	13. Within 45 days after emission testing, the Permittee shall submit to MassDEP a final stack emission test results report.
	14. The Permittee shall conduct sound impact testing to demonstrate that the Facility does not cause any sound impacts in excess of MassDEP's Noise Policy. This testing may be conducted concurrently with FERC's required sound impact testing. The sound impact testing shall be conducted within 90 days of the date of this Plan Approval or in a timeframe as required by FERC, whichever comes later. A pretest protocol shall be submitted to MassDEP at least 30 days prior to the sound impact testing.

Table 9 Key:

CMR = Code of Massachusetts Regulations
CO = Carbon Monoxide
EU = Emission Unit Number
FERC = Federal Energy Regulatory Commission
lb/hr = pounds per hour
lb/MMBtu = pounds per million British Thermal Units
MassDEP = Massachusetts Department of Environmental Protection.
NO_x = Nitrogen Oxides

PM = Total Particulate Matter
PM_{10} = Particulate Matter $\leq$ 10 microns in diameter
$PM_{2.5}$ = Particulate Matter $\leq$ 2.5 microns in diameter
ppmvd = parts per million by volume, dry basis
VOC = Volatile Organic Compounds

USEPA = United States Environmental Protection Agency.
$\leq$ = less than or equal to

Table 10

EU	Record Keeping Requirements
1.	1. The Permittee shall maintain average hourly records of the turbine inlet temperature at all times that the turbine is operated. The record shall indicate the actual ambient temperature for each hour the turbine is in operation. On days when the temperature never drops below 0 °F, the record may indicate the average daily temperature.
	2. The Permittee shall maintain records of the daily, monthly, and annual gas flow to the turbine.
	3. The Permittee shall maintain records of: a. the hourly average inlet temperature of the oxidation catalyst bed, b. the hourly average pressure drop across the catalyst bed.
	4. The Permittee shall maintain records of each transient event, the duration of each event, and associated emissions, separate from startup, shutdown, and low temperature events.
	5. The Permittee shall maintain records of each startup, shutdown, the duration of each event, and associated emissions.
	6. The Permittee shall maintain records of the status of SoLoNOx mode at all times that the unit is in operation.
	7.
2.	8. The Permittee shall maintain records of the date, time, duration and quantity of natural gas emitted for each gas release event.
3.	9. The Permittee shall maintain the following records: a. the date of each LDAR inspection, b. components monitored, c. leaks identified, d. date of each repair, e. date of re-monitoring to validate repairs, f. an up to date Delay of Repair list, including the basis for being on the list, g. any additional items to document compliance with the LDAR program.
Facility-wide	10. The Permittee shall maintain adequate records to demonstrate compliance status with all operational, production, and emission limits contained in Table 8A, above. Records shall also include the actual emissions of air contaminant(s) emitted for each calendar month and for each consecutive 12-month period (current month plus prior eleven months). These records shall be compiled no later than the 30th day of the month following each month. An electronic version of the MassDEP approved record keeping form, in Microsoft Excel format, can be downloaded at http://www.mass.gov/eea/agencies/massdep/air/approvals/limited-emissions-record-keeping-and-reporting.html#WorkbookforReportingOn-SiteRecordKeeping. The Permittee may propose an alternative record keeping spreadsheet for approval by MassDEP
	11. The Permittee shall maintain records of monitoring and testing as required by Table 9.
	12. The Permittee shall maintain a copy of this Plan Approval, underlying Application and the most up-to-date SOMP for the EU(s) and PCDs approved herein.

Table 10	
EU	**Record Keeping Requirements**
	13. The Permittee shall maintain a record of routine maintenance activities performed on the approved EU(s), PCD(s) and monitoring equipment. The records shall include, at a minimum, the type or a description of the maintenance performed and the date and time the work was completed.
	14. The Permittee shall maintain a record of all malfunctions affecting air contaminant emission rates on the approved EU(s), approved PCDs and monitoring equipment. At a minimum, the records shall include: date and time the malfunction occurred; description of the malfunction; corrective actions taken; the date and time corrective actions were initiated and completed; and the date and time emission rates and monitoring equipment returned to compliant operation.
	15. The Permittee shall maintain records to ensure sufficient information is available to comply with 310 CMR 7.12 Source Registration.
	16. The Permittee shall maintain records required by this Plan Approval on-site for a minimum of five (5) years.
	17. The Permittee shall make records required by this Plan Approval available to MassDEP and USEPA personnel upon request.
	18. All records required herein shall be maintained on-site. Alternatively, electronic records may be maintained at a remote location, provided the records are readily available upon request.

Table 10 Key:

CMR = Code of Massachusetts Regulations
EU = Emission Unit Number
°F = degrees Fahrenheit
LDAR = Leak Detection and Repair

MassDEP = Massachusetts Department of Environmental Protection.

PCD = Pollution Control Device

SOMP = Standard Operating and Maintenance Procedure
USEPA = United States Environmental Protection Agency

Table 11	
EU	**Reporting Requirements**
Facility-wide	1. The Permittee shall notify MassDEP upon commencement of construction, upon initial startup, and upon commencement of commercial operation of the equipment approved herein. Each notification shall be made within 30 days of the respective milestone.
	2. The Permittee shall notify MassDEP prior to any planned blowdowns with volume expected to be greater than 100,000 scf. The notification shall include the date(s), time(s), and expected duration of the blowdown(s). The notification shall identify the estimated quantity of emissions from the blowdown, steps taken to minimize emissions, and steps taken to minimize any potential nuisance impacts. This notification shall be provided to MassDEP no later than 48 hours prior to the event. The Weymouth Board of Health shall be provided a copy of this notification.

Table 11	
EU	**Reporting Requirements**
	3. The Permittee shall submit to MassDEP all information required by this Plan Approval over the signature of a "Responsible Official" as defined in 310 CMR 7.00 and shall include the Certification statement as provided in 310 CMR 7.01(2)(c).
	4. The Permittee shall notify the Southeast Regional Office of MassDEP, BAW Compliance & Enforcement Chief by telephone: 508-946-2878, email: Sero.Air@massmail.state.ma.us, or fax : (508) 946-2714, as soon as possible, but no later than three (3) business day after discovery of an exceedance(s) of Table 8A, 8B, or 8C requirements. A written report shall be submitted to the Compliance & Enforcement Chief at MassDEP within ten (10) business days thereafter and shall include: identification of exceedance(s), duration of exceedance(s), reason for the exceedance(s), corrective actions taken, and action plan to prevent future exceedance(s).
	5. The Permittee shall report to MassDEP, in accordance with 310 CMR 7.12, all information as required by the Source Registration/Emission Statement Form. The Permittee shall note therein any minor changes (under 310 CMR 7.02(2)(e), 7.03, 7.26, etc.), which did not require Plan Approval.

Table 11 Key:

EU = Emission Unit Number

CMR = Code of Massachusetts Regulations

MassDEP = Massachusetts Department of Environmental Protection.

MMscf = million standard cubic feet

4. SPECIAL TERMS AND CONDITIONS

A. The Permittee is subject to, and shall comply with, the Special Terms and Conditions as contained in Table 12 below:

Table 12	
EU	**Special Terms and Conditions**
1	1. The oxidation catalyst shall not be by-passed at any time.
	2. The oxidation catalyst shall be operated and maintained in accordance with the manufacturer's recommendations.
	3. The turbine and associated compressor shall be operated and maintained in accordance with the manufacturer's recommendations.

Table 12

EU	Special Terms and Conditions
3.	4. Prior to initial startup, the Permittee shall submit a Leak Detection and Repair (LDAR) program for MassDEP review and approval. The LDAR program is in addition to any specific LDAR criteria established in this Plan Approval and at a minimum shall include: a. a system to identify every component that requires monitoring, b. leak definition, which includes, but is not limited to, any visual or audible standards. This is in addition to the standards defined in this Plan Approval, c. monitoring requirements and frequency, d. repair requirements, which is to include standards for initial repair, final repair, and any standards to place an item on a Delay of Repair list, e. employee training, f. recordkeeping. The LDAR program shall be no less stringent than the leak detection and repair requirements contained in 40 CFR 60 subpart OOOOa. Any changes to the LDAR program shall be submitted to MassDEP prior to implementation.
	5. For piping components in natural gas service, a leak shall be emissions in excess of the following: a. For valves & connectors: any detected concentration 500 ppmv, or greater b. For optical gas imaging: any detected emissions.
	6. For piping components in pipeline liquids service, a leak shall be emissions in excess of the following: a. For valves & connectors: any detected concentration 500 ppmv, or greater b. For pump seals: any detected concentration 10,000 ppmv, or greater

Table 12 Key:

EU = Emission Unit Number
ppmv = parts per million by volume
≤ = less than or equal to
LDAR = Leak Detection and Repair
% = percent

B. The Permittee shall install and use an exhaust stack, as required in Table 13, on each of the Emission Units that is consistent with good air pollution control engineering practice and that discharges so as to not cause or contribute to a condition of air pollution. Each exhaust stack shall be configured to discharge the gases vertically and shall not be equipped with any part or device that restricts the vertical exhaust flow of the emitted gases, including, but not limited to, rain protection devices known as “shanty caps” and “egg beaters.”

C. The Permittee shall install and utilize exhaust stacks with the following parameters, as contained in Table 13, for the Emission Units that are regulated by this Proposed Plan Approval:

Table 13					
EU	**Minimum Stack Height Above Ground (feet)**	**Nominal Stack Inside Exit Dimensions (feet)**	**Nominal Stack Gas Exit Velocity Range (feet per second)**	**Nominal Stack Gas Exit Temperature Range (°F)**
1	60	9 note 1	25 – 28	865 - 999
2	various			
3	No stack			

Table 13 Key:

EU = Emission Unit Number

°F = Degree Fahrenheit

Table 13 Notes:

1. Equivalent diameter for rectangular stack

5. GENERAL CONDITIONS

The Permittee is subject to, and shall comply with, the following general conditions:

A. Pursuant to 310 CMR 7.01, 7.02, 7.09 and 7.10, should any nuisance condition(s), including but not limited to smoke, dust, odor or noise, occur as the result of the operation of the Facility, then the Permittee shall immediately take appropriate steps including shutdown, if necessary, to abate said nuisance condition(s).

B. If asbestos remediation/removal will occur as a result of the approved construction, reconstruction, or alteration of this Facility, the Permittee shall ensure that all removal/remediation of asbestos shall be done in accordance with 310 CMR 7.15 in its entirety and 310 CMR 4.00.

C. If construction or demolition of an industrial, commercial or institutional building will occur as a result of the approved construction, reconstruction, or alteration of this Facility, the Permittee shall ensure that said construction or demolition shall be done in accordance with 310 CMR 7.09(2) and 310 CMR 4.00.

D. Pursuant to 310 CMR 7.01(2)(b) and 7.02(7)(b), the Permittee shall allow MassDEP and / or USEPA personnel access to the Facility, buildings, and all pertinent records for the purpose of making inspections and surveys, collecting samples, obtaining data, and reviewing records.

E. This Proposed Plan Approval does not negate the responsibility of the Permittee to comply with any other applicable Federal, State, or local regulations now or in the future.

F. Should there be any differences between the Application and this Proposed Plan Approval, the Proposed Plan Approval shall govern.

G. Pursuant to 310 CMR 7.02(3)(k), MassDEP may revoke this Proposed Plan Approval if the construction work is not commenced within two years from the date of issuance of this Proposed Plan Approval, or if the construction work is suspended for one year or more.

H. This Proposed Plan Approval may be suspended, modified, or revoked by MassDEP if MassDEP determines that any condition or part of this Proposed Plan Approval is being violated.

I. This Proposed Plan Approval may be modified or amended when in the opinion of MassDEP such is necessary or appropriate to clarify the Proposed Plan Approval conditions or after consideration of a written request by the Permittee to amend the Proposed Plan Approval conditions.

J. Pursuant to 310 CMR 7.01(3) and 7.02(3)(f), the Permittee shall comply with all conditions contained in this Proposed Plan Approval. Should there be any differences between provisions contained in the General Conditions and provisions contained elsewhere in the Proposed Plan Approval, the latter shall govern.

6. MASSACHUSETTS ENVIRONMENTAL POLICY ACT

In a letter dated March 15, 2016 and in a follow-up letter dated May 31, 2016 to the Secretariat of the Executive Office of Energy and Environmental Affairs ("EOEEA"), the Town of Weymouth requested an advisory opinion on the applicability of this project to review under the Massachusetts Environmental Policy Act ("MEPA"). The request for Advisory Opinion requested MEPA invoke the Fail-Safe provisions, requiring the proposed project go through the MEPA review process. Secondly, the request for Advisory Opinion indicated that the proposed Atlantic Bridge Project may have been improperly segmented from the proposed Access Northeast Project[8]. The request for Advisory Opinion was published in the June 8, 2016 Environmental Monitor for public review and comment, subject to a 20-day comment period.

In a letter dated July 11, 2016 to the Mayor of the Town of Weymouth, the Secretariat of the EOEEA concluded "that the project is not subject to MEPA review and the project does not meet the criteria for invoking Fail-Safe Review." Additionally, a determination was made that the Atlantic Bridge Project and the Access Northeast Project "are sufficiently distinct in purpose, design, and scope that they have independent utility and can be reviewed separately."

[8] Algonquin has submitted an application for the Access Northeast Project to FERC. Currently, no Air Quality Plan Application has been submitted to MassDEP.

Should you have any questions concerning this Plan Approval, please contact the undersigned by telephone at 508-946-2824, or in writing at the letterhead address.

PROPOSED

Thomas Cushing
Permit Chief
Bureau of Air and Waste

Enclosure

cc: Weymouth Board of Health/Dept. of Health
Weymouth Fire Department
MassDEP / SERO- M. Garcia-Serrano
M. Pinaud
L. Ramos
MassDEP / Boston- K. Kerigan
Y. Tian
Algonquin Gas T. Doyle
Trinity Consultants - D. Cotter