New Nominal 44 MW CoGen Project

Massachusetts Institute of Technology

Prevention of Significant Deterioration Application (40 CFR 52.21)

Submitted to:

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1.0 INTRODUCTION

1.1 Project Overview – Combustion Turbine Expansion

The Massachusetts Institute of Technology (MIT) is located on 168 acres that extend more than a mile along the Cambridge side of the Charles River Basin. The MIT Central Utilities Plant (CUP) has been designed to provide near 100% reliability through maintaining standby units at all times, as the heat and electrical power generated is used to maintain critical research facilities, laboratories, classrooms and dormitories. The CUP provides electricity, steam heat, and chilled water to more than 100 MIT buildings.

The existing CUP consists of a Siemens (ABB) GT10A Combustion Turbine (CT), heat recovery steam generator (HRSG), and electric generator rated at approximately 21 MW and ancillary equipment that started up circa 1995 located in Building 42. It also includes five existing boilers, designated as 3,4,5,7 and 9 and an emergency generator and a number of cooling towers. The CT provides about 60% of current campus electricity, and the steam from the HRSG is used for heating, and steam driven chillers for cooling (cogeneration) many campus buildings via steam and chiller water distribution systems.

MIT has retained Epsilon Associates Inc. (Epsilon) of Maynard, Massachusetts to prepare an air permit application for its proposed development of two nominal 22 MW Combustion Turbines (CT) with supplemental gas fired (134 MMBTU/hr HHV) HRSGs and other proposed changes to the CUP.

A CHP has significant efficiency and environmental advantages, as described by the Massachusetts Department of Environmental Protection (MassDEP)[1]:

> *"In a combined heat and power (CHP) system, the engine or combustion turbine is connected to an electrical generator for electrical power production. The hot exhaust gasses from the engine or combustion turbine are directed through a heat recovery system, such as a boiler, to recover thermal energy for use in heating, cooling, or other uses. This approach eliminates the need for a second combustion unit and therefore eliminates the emissions such a combustion unit would produce. CHP systems make more efficient use of fuel, such as natural gas or fuel oil, than two, separate stand alone, combustion units, one for electricity and one for thermal energy such as steam thus reducing the net emissions of greenhouse gas and other air contaminants."*

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1 Proposed Amendments to 310 CMR 7.00, March 2008

Each CT will fire natural gas with Ultra Low Sulfur Diesel (ULSD) as a backup fuel for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. Each CT will exhaust to its own HRSG with a 134 million Btu per hour (MMBtu/hr) higher heating value (HHV) gas fired duct burner. The HRSG will include selective catalytic reduction (SCR) for Oxides of Nitrogen (NO_x) control, and an oxidation catalyst for the control of Carbon Monoxide (CO) and Volatile Organics (VOC).

1.2 Project Overview – Other Proposed Changes

In addition to the two new CT's, MIT proposes the following other changes:

- addition of a 2 megawatt (MW) ULSD-fired cold start engine unit to be used for emergency power to start the combustion turbines.

- Existing Boilers 3, 4, and 5 will cease burning #6 fuel oil and only burn natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

- Existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. MIT proposes removal of the annual operating restrictions for Boilers 7 and 9, to allow more use of these efficient resources.

  - This fuel changeover will occur within 12 months of the startup of the new CTG units. This will allow for adequate time to finish construction and remove the old tanks to allow for new fuel storage to be built. Once a permit is issued, the units will only burn the #6 fuel oil left in the tanks or run for 48 hours of testing per year per unit, whichever is greater.

- MIT is also replacing cooling towers 1, 2, 3, 4, 5, & 6with three new cooling towers 11, 12, & 13. Existing cooling towers 7, 8, 9 and 10 will remain.

Portions of the project trigger the requirement to submit this MassDEP Major Comprehensive Plan Approval (310 CMR 7.02 - BWP AQ 01).

1.3 Outline of Application

The remainder of this application is organized as follows.

Section 2 provides a detailed description and estimate of emissions for the proposed CHP expansion.

Section 3 describes the PSD applicability to the project.

Section 4 is the Best Achievable Control Technology (BACT) Analysis for the CHP expansion.

Section 5 documents compliance with specific Prevention of Significant Deterioration (PSD) requirements.

Appendices include the application forms, supplemental information, calculation details, and the air quality dispersion modeling results.

2.0 PROJECT DESCRIPTION AND EMISSIONS

2.1 Description of Project Site

MIT is a world-class educational institution which admitted its first students in 1865. Teaching and research—with relevance to the practical world as a guiding principle—continue to be its primary purpose. MIT is independent, coeducational, and privately endowed. Its five schools and one college encompass numerous academic departments, divisions, and degree-granting programs, as well as interdisciplinary centers, laboratories, and programs whose work cuts across traditional departmental boundaries.

MIT is an academic and research facility, and has steam and electricity reliability needs that exceed those of typical industrial facilities. The MIT CUP has been designed to provide near 100% reliability through maintaining standby units at all times, as the heat and electrical power generated is used to maintain critical research facilities, laboratories, classrooms and dormitories in the event of a power outage, gas curtailment, or other emergency.

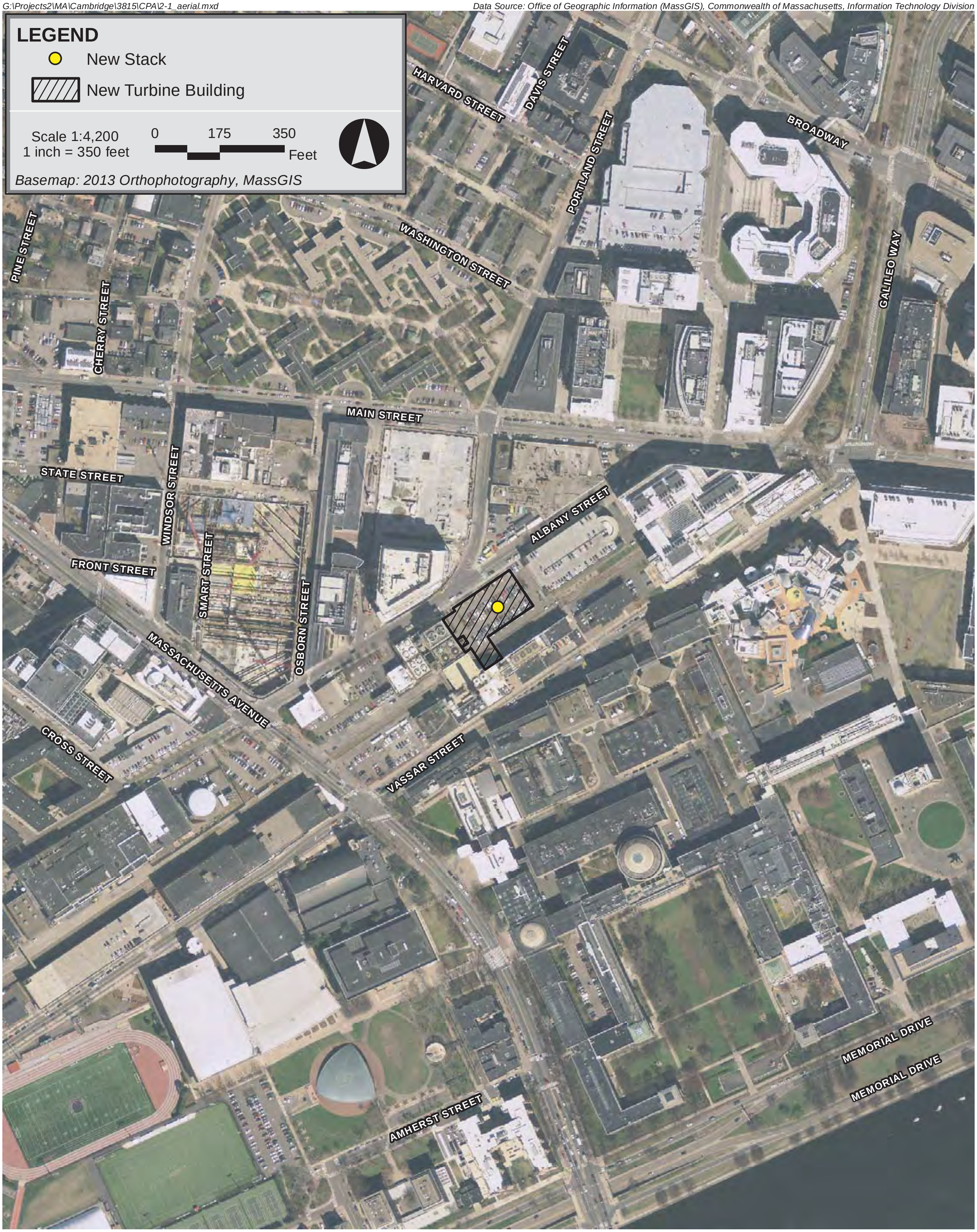
The Central Utility Plant (CUP) is housed in Building 42 (N16, N16A, N16C and 43) which is located between Vassar Street and Albany Street in Cambridge, MA. The new turbines would be housed in an addition to Building 42 to be built in an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The addition to the existing building would be approximately 224′ x 118′ by 63′ above ground level (AGL) tall with three 165′ AGL high flues centrally co-located in a common stack structure. There will be a flue for each turbine vented through its respective Heat Recovery Steam Generator (HRSG). The cold-start engine will be roof-mounted, and have its own exhaust vent above its housing (96.5′ AGL). An aerial locus of the area around the new project is shown in Figure 2-1. The proposed new cogeneration addition and the proposed site for the new turbine stacks and new cold-start engine stack are shown.

Table 2-1 describes the key equipment at the CUP, and lists the equipment designation abbreviations used in operating permit (Application MBR-95-OPP-026).

Table 2-1 Key Existing Equipment at the MIT Plant

Turbine #1	ABB GT10 (GT-42-1A) and Heat Recovery Steam Generator #1 (HRSG-42-1B) (collectively the Cogeneration Unit)
Boiler #3	Wickes 2 drum type R dual fuel (BLR-42-3)
Boiler #4	Wickes 2 drum type R dual fuel (BLR-42-4)
Boiler #5	Riley type VP dual fuel (BLR-42-5)
Generator #01	Emergency Diesel Generator Caterpillar #3516B 2MW (DG-42-6)
Boiler #7	Indeck Dual Fuel BLR-42-7
Boiler #9	Rentech Boiler rated at 125 MMBtu/hr firing natural gas with Ultra Low Sulfur Diesel (ULSD) backup (BLR-42-9)
Cooling Towers	Wet mechanical towers #1,2,3,4,5,6,7,8,9,10.

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC

Figure 2-1

Aerial Locus Map

2.2 Project Description

The proposed project consists of two nominal 22 MW GE LM-2500 (or equivalent) CT units fired primarily on natural gas. Backup ULSD will be used for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. Each turbine will exhaust to its own HRSG with a 134 MMBTU/hr (HHV) gas fired duct burner. The HRSG will include SCR for NO_x control, and an oxidation catalyst for CO and VOC control.

MIT plans an in-service date of the first of two units in 2018 followed by the 2nd unit in 2019. The existing ABB (Siemens) CT will be fully retired following commissioning of the 2nd unit.

In addition to the two new CT's, MIT plans to add a 2 megawatt (MW) ULSD fired cold start engine unit to be used to start the turbines in emergency conditions.

Also, existing Boilers 3, 4, and 5 will cease burning #6 fuel oil and only burn natural gas, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable.

Also, existing Boilers Nos. 7 and 9 will fire natural gas only, with ULSD as a backup fuel for up to the equivalent heat input of 48 hours per year for testing, and up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. MIT proposes removal of the annual operating restrictions for Boilers 7 and 9, to allow more use of these efficient resources.

In conjunction with this project MIT is also replacing cooling towers 1, 2, 3, 4, 5, & 6 with three new cooling towers. Towers 7, 8, 9 and 10 will remain.

Technical specifications are included in Appendix B.

2.3 Source Emissions Discussion

The two new CT's will emit products of combustion from the firing of natural gas or ULSD. Emissions are minimized through the use of clean burning fuels, in combination with post combustion controls. Air emissions, including the natural gas-fired duct burner, are further reduced using Selective Catalytic Reduction (SCR) for post-combustion control of NO_x and an oxidation catalyst for post-combustion control of CO.

Because proposed ULSD use is very limited, the new CT's have the opportunity to use dry low-NOx combustors instead of water injection.

Emissions from the new cold-start engine will be minimized through the use of clean burning fuels.

Existing boilers will have the same short-term emission rates as currently permitted, with the same emissions controls.

The new cooling towers will emit particulates. Emissions will be minimized through the use of high efficiency drift eliminators.

Potential short-term and long-term emission rates of the Project are summarized below. Detailed calculations are included in Appendix C.

Table 2-2 Proposed Emission Rates for CTGs

Pollutant	Emission Rate, Natural Gas fired	Emission Rate, ULSD fired	Duct Burner Emission Rate (Natural Gas only)	Control Technology
Nitrogen oxides (NO_x)	2.0 ppm	9.0 ppm	0.011 lb/MMBtu	SCR
Carbon Monoxide (CO)	2.0 ppm	7.0 ppm	0.011 lb/MMBtu	Oxidation Catalyst
Volatile Organic Compounds (VOC)	1.7 ppm	7.0 ppm	0.03 lb/MMBtu	Oxidation Catalyst
Particulate Matter ($PM/PM_{10}/PM_{2.5}$)	0.02 lb/MMBtu	0.04 lb/MMBtu	0.02 lb/MMBtu	Low ash fuels
Sulfur dioxide (SO_2)	0.0029 lb/MMBtu	0.0016 lb/MMBtu	0.0029 lb/MMBtu	Low sulfur fuels
Carbon Dioxide (CO_2)	119 lb/MMBtu	166 lb/MMBtu	119 lb/MMBtu	N/A
Ammonia (NH_3)	2.0 ppm	2.0 ppm	2.0 ppm	SCR

ppm = parts per million (dry volume, corrected to 15% oxygen
lb/MMBtu = pounds per million British Thermal Unit
Short-term NO_x, CO, VOC, and NH_3 emission rates are for full-load, steady-state operations.

Table 2-3 Proposed Project Potential Emissions

	Turbines & HRSGs	Cold-start Engine	Boiler 7	Boiler 9	Cooling Towers	Total
NO_x	24.6	5.3	1.9	0.65	-	32.3
CO	17.1	0.33	2.2	2.8	-	22.4
VOC	21.6	0.17	7.7	9.7	-	39.2
PM	56.6	0.06	1.9	2.6	0.92	62.0
SO_2	7.9	0.004	0.35	0.45	-	8.7
CO_2	333,530	480	29,320	37,970	-	401,300

Boiler 7 and Boiler 9 are proposed increases in potential emissions
CO_2 emission rates are rounded to the nearest ten tons

The basis for each proposed emission limit is described in Section 4, and a summary of the proposed emission limits and compliance mechanisms is in Section 4.11.

2.4 Exhaust Design Configurations

Emissions from the existing boilers #3, #4 and #5 are vented out the brick stack on the roof of the CUP. The existing turbine #1 stack and the emergency generator stack are also located on the roof of the CUP. Existing boilers #7 and #9 are located adjacent to Building N16A at 60 Albany Street, across the railroad tracks from the main CUP building. Exhaust from both Boiler #7 and Boiler #9 are combined and vent through a common stack.

The two new CTs with HRSG's and ancillary equipment will be located in an addition to Building 42 to be built in an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The project layout is shown in Figure 2-1. . There will be two 165' AGL high flues centrally co-located in a common stack structure. There will be a flue for each turbine vented through its respective Heat Recovery Steam Generator (HRSG). The cold start engine flue will be located atop its housing (96.5' AGL).

2.5 Project Schedule

Pending approvals, MIT intends to have the first CT operating in 2018 followed by the 2nd unit in 2019. The existing Siemens CT will be fully retired following commissioning of the 2nd unit. Other Project changes (cold-start engine, cooling towers, Boilers 3, 4, & 5 fuel switch) will be scheduled through 2018 and early 2019. MIT proposes to increase allowable operating hours of the more efficient Boilers 7 and 9 immediately upon approval.

3.0 PSD APPLICABILITY

Under federal and state air laws, the MassDEP and the EPA have promulgated air quality regulations that establish ambient air quality standards and emission limits. These standards and limits impose design constraints on new facilities and provide the basis for an evaluation of the potential impacts of proposed projects on ambient air quality. This section briefly describes these regulations and their relevance to the proposed CHP expansion.

3.1 Prevention of Significant Deterioration (PSD) Review

Prevention of Significant Deterioration review is a federally mandated program for review of new major sources of criteria pollutants or major modifications to existing sources. In Massachusetts, as of April 2011 MassDEP has "full responsibility for implementing and enforcing the federal PSD regulations."

MIT is an existing major stationary source of air emissions per the federal PSD program at 40 CFR 52.21(b)(1)(i)(b). The Project will create a significant emissions increase per 40 CFR 52.21(b)(23)(i) for CO_2, PM_{10} and $PM_{2.5}$ as described below. Therefore, the Project will be a major modification of an existing major source, subject to the requirement to obtain a PSD permit.

The emissions from the project are compared to PSD thresholds in Table 3-1.

Table 3-1 Comparison of Project Emissions to PSD Triggers

Pollutant	Estimated Potential Emission Rates (tpy)	Significant Emission Rate (tpy)	Significant?
NO_x	32.5	40	No
CO	22.4	100	No
VOC	39.2	40	No
PM_{10}	62.1	15	Yes
$PM_{2.5}$	62.1	10	Yes
SO_2	8.7	40	No
CO_2	401,300	75,000	Yes
Lead	Negligible	0.6	No
Fluorides	Negligible	3	No

Table 3-1 Comparison of Project Emissions to PSD Triggers (Continued)

Pollutant	Estimated Potential Emission Rates (tpy)	Significant Emission Rate (tpy)	Significant?
Sulfuric Acid Mist	<7	7	No
Hydrogen Sulfide	None expected	10	No
Total reduced sulfur	None expected	10	No
Reduced sulfur compounds	None expected	10	No

The PSD regulations define "minor source baseline date" at 40 CFR 52.21(b)(14)(ii) as "the earliest date after the trigger date on which… a major modification subject to 40 CFR 52.21… submits a complete application". Therefore, if the minor source baseline date has not been established for the baseline area, this application will establish the baseline date when it is determined to be complete. EPA has established increment standards for PM_{10} and $PM_{2.5}$. The Project will comply with all applicable PSD requirements including demonstrating BACT and complying with all NAAQS and PSD increments.

4.0 BACT ANALYSIS

The MIT CHP expansion will meet Massachusetts and federal BACT through the use of clean fuels, clean combustion, and post-combustion controls (Selective Catalytic Reduction and oxidation catalyst). The applicable requirements are discussed in detail in this Section, followed by descriptions of how BACT is applied for each separate PSD-regulated pollutant.

4.1 PSD BACT

The PSD regulations include (at 40 CFR 52.21(j)(3)) a requirement to "apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase." The PSD definition of BACT is similar to the Massachusetts definition.

> *"Best available control technology means an emissions limitation... based on the maximum degree of reduction... which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant."*

The pollutants subject to the PSD BACT requirement are PM2.5, PM10, and CO2e. A formal top-down analysis is presented for particulate matter and CO2e.

4.2 Particulate Matter BACT for the Combustion Turbines and Duct Burners

Because particulate matter emissions are subject to both federal and Massachusetts BACT requirements, this BACT analysis follows the federal guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, USEPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the NESCAUM BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

Available fuels and emission controls are the same for the turbine and the duct burner. Also, data on emission limits achieved-in-practice are generally based on total emissions from turbine and duct burner firing. This BACT analysis therefore applies to the combined emissions of the turbine and the duct burner.

4.2.1 BACT Applicability

...the BACT determination must separately address..., for each regulated pollutant... air pollution controls for each emissions unit or pollutant emitting activity subject to review.

While "particulate matter" is listed as a regulated pollutant, EPA rescinded the national ambient air quality standard for particulate matter in favor of a PM_{10} standard in 1987, and recent statutory and regulatory provisions impose controls and limitations on PM_{10}, not particulate matter.

Particulate matter consists of two broad categories: filterable PM and condensable PM. Based on recent guidance from the MassDEP on other projects, this analysis addresses total particulate, filterable plus condensable.

$PM_{2.5}$ is a subset of PM_{10}; there is very limited data on $PM_{2.5}$ emission limits achieved in practice, and there is considerable uncertainty regarding $PM_{2.5}$ test methods. Much or most of the filterable PM_{10} emissions will be 2.5 microns or smaller, and all of the condensable PM_{10} emissions are generally considered 2.5 microns or smaller. BACT techniques for $PM_{2.5}$ control will be the same as for PM_{10} control. For all of these reasons, this application makes the conservative assumption that all PM_{10} emitted from the CHP expansion is $PM_{2.5}$. The BACT emission rates reviewed in this analysis are for PM, PM_{10} and $PM_{2.5}$. Throughout this application, the term PM refers to PM/PM_{10}/$PM_{2.5}$, filterable plus condensable.

4.2.2 Step 1–Identify All Control Technologies

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion control, including:
  - Fabric filtration
  - Electrostatic precipitation
  - Wet scrubbing
  - Cyclone or multicyclone collection
  - Side-stream separation
- The use of clean fuels and good combustion control

> Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

The list above includes fuel combustion techniques, and the use of clean fuels which can be considered "fuel cleaning or treatment."

This includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

… in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

The use of clean fuels can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

The source category in question is the production of electricity in a combustion turbine. Existing particulate controls are limited to the use of clean fuels and good combustion techniques.

Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the post-combustion control options listed above.

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels and good combustion techniques.

4.2.3 Step 2–Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically infeasible*
- Use of clean fuels and good combustion control: *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- **Post-combustion control**. All available post-combustion controls have a limitation to how clean an exhaust concentration they can achieve. The minimum outlet concentration achievable using post-combustion control is generally higher than the inlet concentration achievable using clean fuels. Therefore, the installation of post-combustion controls will not reduce particulate emissions.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

MIT has made a good faith effort to compile appropriate information from available information sources (per EPA guidance). Information sources considered included:

- EPA's RACT/BACT/LAER Clearinghouse and Control Technology Center - Information from the Clearinghouse[2] was reviewed. No facilities are identified that use post-combustion control on a combustion turbine smaller than 25 MW that fires natural gas and/or distillate oil.

- Best Available Control Technology Guideline - South Coast Air Quality Management District - The Guideline[3] has no guidance for particulate matter;

- Control technology vendors - An online review of vendors[4] does not find any offering post-combustion control for particulate matter from combustion turbines firing natural gas or distillate oil;

2 http://cfpub.epa.gov/rblc/ reviewed July 2014

3 http://aqmd.gov/home/permits/bact/guidelines reviewed March 2014

- Federal/State/Local new source review permits and associated inspection/performance test reports - a good faith effort to review permits available online found information as presented below;

- Environmental consultants - Consultants at Epsilon Associates, Inc. reviewed available information on current and past projects;

- Technical journals, reports and newsletters, air pollution control seminars - a review of papers posted by the Air and Waste Management Association[5] found no recent papers associated with particulate emission rates achievable from gas and ULSD-fired combustion turbines; and

- EPA's policy bulletin board - A review of the online OAR Policy and Guidance[6] websites found no references to specific recent BACT emission limits or technologies for particulate matter from gas and ULSD-fired combustion turbines. Particulate control from boilers was reviewed in the development of the NESHAP rules for industrial, commercial, and institutional boilers under 40 CFR 63[7]. EPA concluded that, for boilers firing gaseous fuel with liquid fuel backup, "no existing units were using control technologies that achieve consistently lower emission rates than uncontrolled sources."

The EPA Clearinghouse was queried for combustion turbines firing natural gas or distillate oil, operating in combined-cycle or cogeneration mode, sized smaller than 25 MW. Facilities listed in the Clearinghouse as having only filterable particulate matter limits were excluded. Additional facilities were added based on Epsilon experience.

No comparable projects were found that used post-combustion control. Key projects are summarized as follows:

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4 http://www.icac.com/?Publications, search March 2014 for particulate matter control equipment applicable to natural gas or ULSD combustion.

5 http://awma.org/search and http://portal.awma.org/store/, March 2014. Searches for "Particulate & Natural Gas" and "Particulate & Distillate." No applicable papers were identified.

6 http://epa.gov/ttn/oarpg/new.html and http://epa.gov/ttn/oarpg/ramain.html. reviewed March 2014

7 EPA-452/F-03-031

Table 4-1 Summary of available data on PM turbine emission limits

Determination	PM emission limit	Converted
CARB Database determination for Los Angeles County Sanitation District, 9.9 MW Solar combustion turbine, combined cycle, firing landfill gas	5.7 lb/hr PM	~0.038 lb/MMBtu at full load
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	1.04 lb/hr PM firing natural gas (type not specified, assume FILTERABLE)	~0.0052 lb/MMBtu at full load (type not specified, assume FILTERABLE)
RBLC determination for Maui Electric, 20 MW turbine, combined cycle	19.7 lb/hr PM firing No. 2 fuel oil	~0.099 lb/MMBtu firing No. 2 fuel oil
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	0.022 lb/MMBtu PM_{10} (filterable & condensable) firing natural gas, 0.04 lb/MMBtu firing ULSD (other limits also listed).	0.022 lb/MMBtu PM_{10} (filterable & condensable) firing natural gas, 0.04 lb/MMBtu firing ULSD
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	0.03 lb/MMBtu PM_{10} firing natural gas); 0.036 lb/MMBtu PM_{10} firing diesel.	0.03 lb/MMBtu PM_{10} firing natural gas); 0.036 lb/MMBtu PM_{10} firing diesel.
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	3.4 lb/hr PM firing natural gas (with and without duct burning); 4.5 lb/hr PM firing ULSD.	The Gillette Boston application states the emission limits are based on 0.022 lb/MMBtu firing natural gas & 0.037 lb/MMBtu firing ULSD, but that does not appear to correspond to the rated capacity of the permitted equipment. Based on available equipment data, the calculated limits would be 0.017 lb/MMBtu firing natural gas with the duct burner and 0.053 lb/MMBtu firing ULSD.
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	1.9 lb/hr firing natural gas without duct burning; 2.34 lb/hr firing natural gas with duct burning; 2.88 lb/hr firing ULSD	~0.021 lb/MMBtu firing natural gas ~0.034 lb/MMBtu firing ULSD
MassDEP operating permit for MATEP, Alston turbine & HRSG	0.025 lb/MMBtu firing gas, 0.040 lb/MMBtu firing ULSD (interim limits)	0.025 lb/MMBtu firing gas 0.040 lb/MMBtu firing ULSD
MassDEP operating permit for Biogen, Solar Taurus 60 turbine & HRSG	0.028 lb/MMBtu PM firing natural gas (with and without duct burning); 0.056 lb/MMBtu PM firing ULSD	0.028 lb/MWh firing natural gas 0.056 lb/MWh firing ULSD
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	3.3 lb/hr firing natural gas with or without duct burning; 3.7 lb/hr firing ULSD	0.022 lb/MMBtu firing natural gas 0.04 lb/MMBtu firing ULSD
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	0.0075 lb/MMBTU filterable PM firing natural gas	0.0075 lb/MMBTU filterable PM firing natural gas

4.2.4 Step 3–Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

The only remaining control technology is the use of clean fuels and clean combustion. Requested data is summarized below.

Table 4-2 Summary of PM effectiveness of clean fuels & combustion

Control efficiencies (percent pollutant removed)	Not applicable (inherently clean technology used)
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C, potential emissions are 6.5 lb/hr firing gas, 11.2 lb/hr firing ULSD in each turbine (and gas in the duct burner), and 40 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	Not applicable (inherently clean technology used)
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels. As of the time of this application natural gas prices are low on an annual basis, but high during peak winter use periods.
Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient combustion turbine with heat recovery and low energy impacts.

4.2.5 Steps 4&5–Select BACT

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

Consistent with the analysis presented above, MIT proposes the use of a clean fuels, and clean combustion, achieving a total $PM/PM_{10}/PM_{2.5}$ emission rate of 0.02 lb/MMBtu firing gas and 0.04 lb/MMBtu firing ULSD as the top alternative for BACT. These limits are comparable to (and slightly lower than) recent projects of similar size (Cornell, UMass Amherst, Gillette, and Harvard). The proposed BACT emission limitations are the maximum degree of reduction achievable, taking into account the scarcity of comparable units with emission limits demonstrated-in-practice, the continued concerns with the accuracy & repeatability of the stack test method (EPA Method 202), and the limited technical opportunities to directly control and reduce particulate emissions.

4.3 GHG BACT

Similar to particulate matter and CO, GHG emissions are subject to both federal and Massachusetts BACT requirements, so this BACT analysis follows the New Source Review Workshop Manual, and the NESCAUM BACT Guideline. In addition, this BACT analysis refers to the March 2011 EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases.[8]"

Available fuels and emission controls are the same for the turbine and the duct burner. Also, data on emission limits achieved-in-practice tend to be based on total emissions from turbine and duct burner firing. This BACT analysis therefore applies to the combined emissions of the turbine and the duct burner.

8 EPA-457/B-11-001, http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

4.3.1 BACT Applicability

…the BACT determination must separately address…, for each regulated pollutant… air pollution controls for each emissions unit or pollutant emitting activity subject to review.

The PSD regulations at 40 CFR 52.21(b)(49)(i) define GHG as a single pollutant as the aggregate group of the following six gases: carbon dioxide (CO_2), nitrous oxide (N2O), methane (CH4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). Of these, HFCs, PFCs, and SF6 are not products of combustion and will not be emitted by the project. The N2O will be controlled as NOx by the SCR, and the CH4 will be controlled by good combustion practices. This BACT analysis focuses on CO_2 emissions as the primary GHG component. Emissions calculations are as CO_2-equivalent, or CO_2e.

4.3.2 Step 1–Identify All Control Technologies

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Carbon Capture Sequestration - (CCS)
- The use of clean fuels, good combustion control, and efficient operation

Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

The list above includes fuel combustion techniques, and the use of clean fuels which can be considered “fuel cleaning or treatment.”

This list includes technologies employed outside the United States.

MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

…in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

The use of clean fuels can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

The source category in question is the production of electricity in a combustion turbine. Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the control options listed above.

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. The top control technology found is the use of clean fuels and good combustion techniques. For example, all the determinations in Table 4-6, above fire natural gas or distillate oil. Each has no GHG emission limit, or a GHG emission limit on a mass basis.

A RACT/BACT/LAER Clearinghouse search finds a single facility with GHG emission limits[9]. Midwest Fertilizer in Mount Vernon IN has two "open-simple cycle combustion turbines with heat recovery" each with a limit of 12,666 "BTU/KW-H, MINIMUM". It is not clear that this limit is comparable to the Project.

4.3.3 Step 2–Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically infeasible*
- Use of clean fuels, good combustion control, and energy efficiency: *technically feasible*

9 http://cfpub.epa.gov/rblc/index.cfm, Categories 16.210 and 16.290 (Small Combustion Turbines <25 MW, Combined Cycle and Cogeneration, natural gas and liquid fuel), pollutants CO2 or CO2e over the last 10 years.

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- **Carbon Capture Sequestration**. For CCS to be technically feasible, each of the following steps needs to be technically feasible: 1) capture; 2) compression; 3) transport; and 4) sequestration.

  1) **Capture.** Carbon capture is technically infeasible for the MIT project site. There is insufficient space to for the required absorption system. Also, the absorption process has not been demonstrated on a power generating unit beyond the pilot-scale or side-stream scale. Finally, the handling of the absorption media (which could be ammonia, monoethanolamine, or other amine solution) may not be feasible in an urban setting.

  2) **Compression.** Compressing the CO_2 to about 2,000 pounds per square inch for transport may or may not be technically feasible at the MIT site. There may or may not be space for the required equipment, and it may be impossible to operate the needed compressors and comply with Cambridge noise regulations.

  3) **Transport.** The transport of CO_2 from the MIT site is technically infeasible. A pipeline of pressurized gas or supercritical fluid CO_2 through Cambridge streets would not be able to obtain the necessary approvals, and would cost much more than the value of the entire project.

  4) **Sequestration.** Sequestration of CO_2 from the MIT site is technically infeasible. Sequestration is the injection and long-term storage of CO_2 in geologic formations such as coal seams and oil & gas reservoirs. There are no candidate geologic formations near enough to make the project feasible. Sequestration has in any event not been demonstrated in practice for control of CO_2 from electric generation.

  Also, the EPA 2011 GHG guidance notes:

  > …in cases where it is clear that there are significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (e.g., sources that emit CO_2 in amounts just over the relevant GHG thresholds…) a much less detailed

> justification may be appropriate and acceptable for the source. In addition, a permitting authority may make a determination to dismiss CCS for a small natural gas-fired package boiler, for example, on grounds that no reasonable opportunity exists for the capture and long-term storage or reuse of captured CO_2 given the nature of the project.

The proposed turbine and duct burner emits CO_2 in amounts just over the relevant GHG thresholds, and has a similar emission profile to a natural gas-fired package boiler.

Since most or all steps in CCS are not technically feasible for the MIT project, CCS is not technically feasible.

- Use of clean fuels, good combustion control, and energy efficiency: Technically feasible.

4.3.4 Step 3–Rank Remaining Control Technologies By Control Effectiveness

> In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:
>
> - control efficiencies (percent pollutant removed);
> - expected emission rate (tons per year, pounds per hour);
> - expected emissions reduction (tons per year);
> - economic impacts (cost effectiveness);
> - environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
> - energy impacts.

The only remaining control technology is the use of clean fuels and clean combustion. Requested data is summarized below.

Table 4-3 Summary of CO_2e effectiveness of clean fuels & combustion

Control efficiencies (percent pollutant removed)	Not applicable (inherently clean technology used)
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C, potential emissions are 46,401 lb/hr firing gas, 57,083 lb/hr firing ULSD in each turbine (and gas in the duct burner), and 333,530 tons/year combined total. .
Expected emissions reduction (tons per year)	Not applicable (inherently clean technology used)
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels. As of the time of this application natural gas prices are low on an annual basis, but high during peak winter use periods.
Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of system efficiency; the proposed CHP is an efficient combustion turbine with heat recovery and low energy impacts.

4.3.5 Steps 4&5–Select BACT

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

Consistent with the analysis presented above, MIT proposes the use of a clean fuels, and clean combustion, achieving a total CO_2e emission are 46,401 lb/hr firing gas and 57,083 lb/hr firing ULSD in the turbine (and gas in the duct burner) as the top alternative for BACT.

As discussed in Section 1.1, this CHP project will promote very efficient fuel use by generating both electricity and useful heat. Per the Massachusetts Energy and Environmental Affairs website[10]:

> *"A Combined Heat and Power (CHP) system (or cogeneration) can effectively and reliably generate useful heat and electric power using less fuel than a typical system that generates power only. CHP systems offer tremendous opportunities for customers with predictable and consistent heat and power needs (particularly large commercial, industrial, and institutional facilities), providing potential for significant economic savings and reductions in fuel consumption and greenhouse gas emissions."*

A well-designed CHP system is well matched to the electric and thermal loads it is serving, and lb/MWh limits, which are primarily intended to encourage electric power generation efficiency, would limit MIT's ability to operate the facility in the most efficient manner to serve both the electric, chilled water and thermal demands of the campus. A limit on lb/MWh that includes thermal energy output could be complicated to calculate, and could serve to reduce overall CUP plant efficiency by restricting MIT's ability to operate its most efficient equipment as-needed to respond to changing campus needs. MIT therefore requests GHG limits on a mass basis only.

4.4 Proposed CTG & HRSG Emission Limits

Based on guidance in the NSR Workshop Manual, emission limits should be "enforceable as a practical matter." Because the duct burner emissions are entirely commingled with the combustion turbine emissions, it is not practical to enforce separate permit limits.

MIT proposes combined, mass-based emissions limits that reflect BACT as described above. This is consistent with the plan approval recently issued by MassDEP for very similar projects (The Gillette Company, Boston, February 2, 2010 and Harvard University, Cambridge, October 29, 2013). The proposed emission limits and compliance mechanisms are summarized in Table 4-4, below. Supporting calculations are in Appendix C.

10 http://www.mass.gov/eea/energy-utilities-clean-tech/energy-efficiency/ee-for-business-institutions/combined-heat-power/

Table 4-4 Proposed Short-Term Emission Limits Per CHP Unit

Operating Condition	Pollutant	Proposed Limit Per CHP Unit	Proposed Compliance Method
Natural gas, with or without duct firing	PM	6.5 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	CO_2e	46,401 lb/hr	Initial calculations based on rated capacity, emission factor
ULSD in turbine, with or without natural gas duct firing	PM	11.23 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	CO_2e	57,083 lb/hr	Initial calculations based on rated capacity, emission factor

Emissions of CO_2 will be limited through the use of clean fuels and efficient operation.

MIT proposes that the short-term limits, above, exclude startup periods, shutdown periods, and fuel changes. MIT will not operate the CTG/HRSG at power generating loads below 25 percent of combustion turbine rated capacity, excluding start-up or shutdown periods or fuel changes. Startup and shutdown emissions will be proposed later after a period of actual operation.

For long-term emission rates, MIT proposes to restrict operation on ULSD up to the equivalent heat input of 168 hours per year including testing and periods when natural gas is unavailable. Proposed long-term emission limits are summarized in Table 4-5, below. The proposed long-term emission rates include startup periods, shutdown periods, and fuel changes.

Table 4-5 Proposed Long-Term Emission Limits for the CTGs and HRSGs

PM	48.3 ton/12-month rolling period, based on stack test data and fuel use
CO_2e	333,530 ton/12-month rolling period, based on emission factors and fuel use

4.5 Top-Case BACT for Cooling Towers

The cooling towers will use high efficiency drift eliminators with an efficiency of 0.0005% of the circulating water rate. With a historical total TDS concentration of 2,064 mg/L and a circulating water rate of 13,500 gpm, each of the three new cooling towers would be exempt from Air Plan Approval per 310 CMR 7.02(2)(b)(6) based on the circulating rate, but the TDS blowdown is just above the exemption level of 1,800 mg/L. The proposed drift eliminators are proposed as top case BACT and result in PM emissions of 0.070 lb/hr from each cooling tower.

4.6 Top-Case BACT for Cold-Start Engine

The cold-start engine falls within the range of sources subject to the MassDEP ERP Standards for emergency engines and turbines at 310 CMR 7.26(42). The ERP limitations for emergency engines and turbines are compliance with the applicable emission limits set by the US EPA for non-road engines (40 CFR 89), use of ULSD fuel and hours of operation limited to no more than 300 per 12-month rolling period. The Facility will obtain the appropriate engine supplier certification for these units. These design and operating restrictions constitute BACT pursuant to 310 CMR 7.02(5).

Specifically regarding BACT for PSD-applicable Pollutants:

- Particulate Matter: Available control technologies are clean combustion and use of an active diesel particulate filter (DPF). Both of these technologies are technically feasible, although MIT is not aware of any use of a DPF for an emergency engine, so the use of a DPF is not demonstrated in practice for this category of equipment. A DPF could be more effective than the use of clean combustion alone, but given the very low annual PM emission rates for the cold-start engine its use would not be cost-effective (control costs would likely exceed $100,000 per ton of PM removed).

- GHG: Add-on controls (CCS) are not technically feasible. The application (emergency black-start power generation) requires reliable on-site fuel storage with no outside energy required to start the generator. The use of ULSD is the lowest-emitting fuel for this purpose that can be reliably obtained and safely and simply stored.

4.7 Top-Case BACT for Boilers 7 and 9

The existing operating permit limits for Boilers 7 and 9 comply with MassDEP guidance for Top-Case BACT. Table 4-6 below compares the proposed limits for Boilers 7 and 9 compared to the relevant MassDEP BACT Guidance. While Boiler 7 is rated at just under 100 MMBtu/hr, it is compared to top-case BACT for boilers 100 MMBtu/hr and larger.

Table 4-6 Proposed Top-Case BACT for Boilers 7 and 9

	Natural Gas (125.8 MMBTU/hr)		ULSD (119.2 MMBTU/hr)	
Pollutant	Limit (lb/MMBTU)	BACT Guidance (lb/MMBTU)	Limit (lb/MMBTU)	BACT Guidance (lb/MMBTU)
PM10/PM2.5	0.01	0.01	0.03	0.03
CO2	119	N/A	166	N/A

Specifically regarding BACT for PSD-applicable Pollutants:

- Particulate Matter: Available control technologies are clean fuels and clean combustion. The use of add-on controls (fabric filtration, electrostatic precipitation, scrubbing) is not technically feasible because the inlet particulate loading is too low for any of these to effectively remove further particulates.

- GHG: Add-on controls (CCS) are not technically feasible. The use of natural gas with ULSD backup is the lowest-emitting fuel choice that allows MIT to meet the project's reliability needs.

Additional information for BACT from Boilers 7 and 9 was provided in the MCPA applications for these boilers. Attached in Appendix B are pages from the Boiler 9 MCPA BACT analysis, which are still applicable and are incorporated by reference into this application.

5.0 PSD COMPLIANCE

This section documents how the PSD application process will meet the requirements as described by applicable guidance.

5.1 NSR Workshop Manual Guidance

The preface of the EPA NSR Workshop Manual lists five requirements for an applicant to obtain a PSD permit. Each is copied in boxes below, along with a brief description of how MIT intends to fulfill the requirements:

1. apply the best available control technology (BACT);

Sections 4.5 and 4.6 of the application include BACT analyses for the pollutants subject to PSD review, done on a case-by-case basis considering energy, environmental, and economic impacts in determining the maximum degree of reduction achievable.

2. conduct an ambient air quality analysis;

Appendix A contains an air quality analysis to demonstrate that the proposed new pollutant emissions would not violate either the applicable NAAQS or the applicable PSD increment.

3. analyze impacts to soils, vegetation, and visibility;

Appendix A contains an air quality analysis to demonstrate that the proposed new pollutant emissions would not violate either the applicable NAAQS or the applicable PSD increment.

4. not adversely impact a Class I area; and

Appendix A includes an analysis to demonstrate that the proposed emissions increases would not significantly impair visibility, or impact on soils or vegetation. No significant impacts are expected from general commercial, residential, industrial, and other growth associated with the project.

5. undergo adequate public participation by applicant.

MIT expects that the application review process will include: consultation letters to tribes, U.S. Fish and Wildlife Service (FWS), National Marine Fisheries Service (NMFS), and the Massachusetts State Historic Preservation Officer (SHPO); enhanced public participation through the MEPA Environmental Justice policy; public notice and comment period; EPA comment period; and a hearing if requested. Additional details are in Section 5.2, below.

5.2 PSD Program Delegation Agreement

The April 2011 document "*Agreement for Delegation of the Federal Prevention of Significant Deterioration (PSD) Program by the United States Environmental Protection Agency, Region I to the Massachusetts Department of Environmental Protection*" contains specific instructions for the review and approval of PSD permits by MassDEP. Key text is copied in boxes below, followed by a description of how the application process will satisfy the instructions.

> Require PSD permit applicants to submit, as part of their PSD permit applications, any information necessary to determine whether issuance of such permits: (1) may affect federally-listed threatened or endangered species or the designated critical habitat of such species; and, if so, whether permit issuance is likely to adversely affect such species/designated critical habitat and/or jeopardize the continued existence of such species or result in the destruction or adverse modification of designated critical habitat; (2) has the potential to cause effects on historic properties; and, if so, whether such effects may be adverse; and/or (3) has the potential to affect Indian tribes.

The proposed project involves one new building (at a current parking lot). No critical habitat will be affected. Similarly, no changes to historic properties are proposed and no impacts to historic properties are expected. MIT is unaware of any potential for the project to affect Indian tribes.

> Require the applicant to (1) notify, within 5 working days after submitting a PSD permit application, the following agencies, and (2) provide a copy of the permit application if requested by one of the agencies:
>
> A. U.S. Fish and Wildlife Service (FWS);
>
> B. National Marine Fisheries Service (NMFS);
>
> C. The Massachusetts State Historic Preservation Officer (SHPO);
>
> D. The Tribal Historic Preservation Officer (THPO) and, via separate copy, the tribal environmental director, for the Mashpee Wampanoag Tribe and for the Wampanoag Tribe of Gay Head (Aquinnah);
>
> E. When required by the NHPA Letter: the SHPO for a bordering state, and/or the THPO for a federally-recognized Indian tribe in a bordering state.

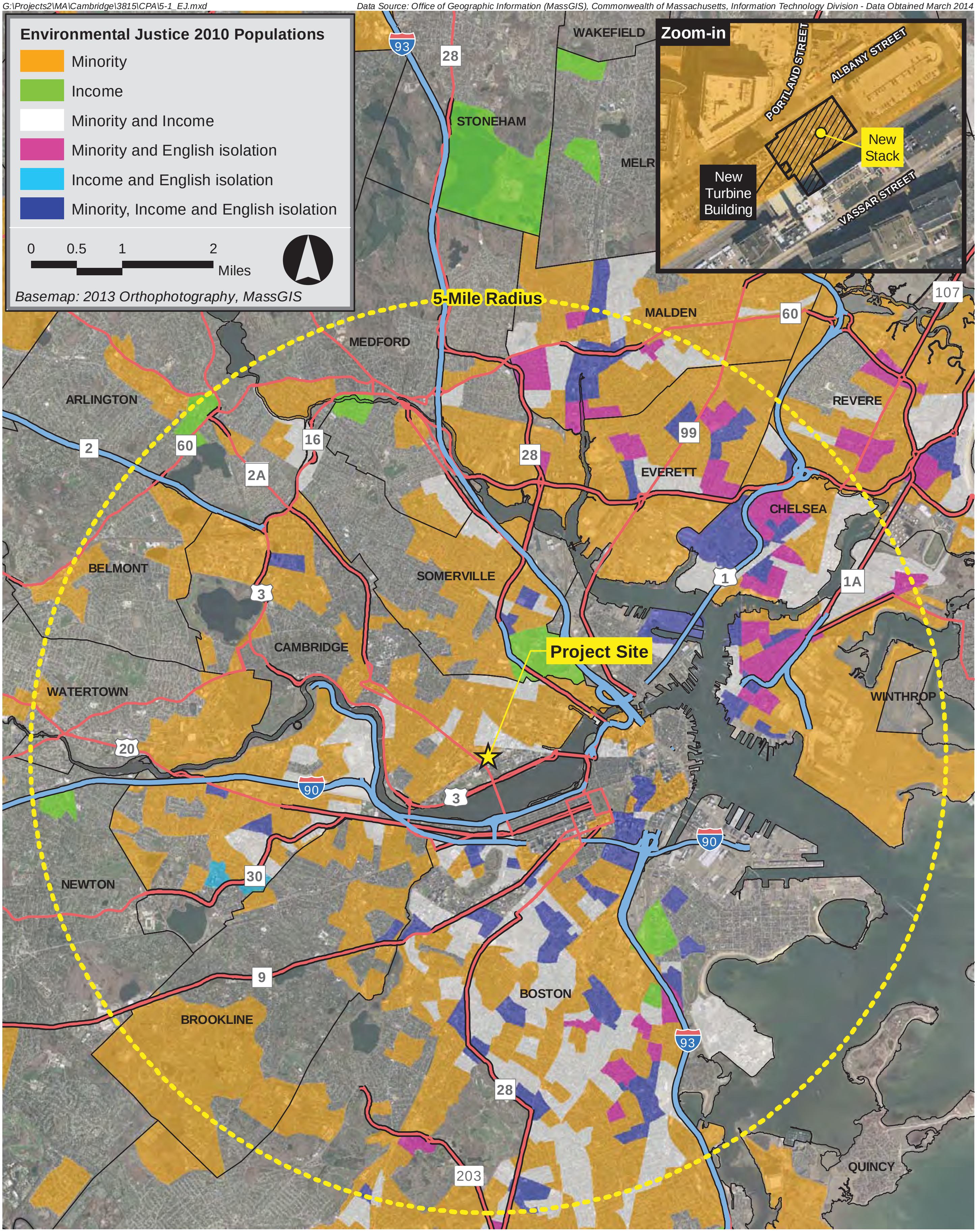
MIT will submit the notification letters either upon MassDEP's instruction or shortly after submittal of the PSD Application.

> MassDEP will follow EPA policy, guidance, and determinations as applicable… including:
>
> …The requirement to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations, as set forth in *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, Exec. Order 12,898, 59 Fed. Reg. 7,629 (Feb. 16, 1994).

The executive order referenced above instructs agencies to develop an environmental justice strategy to, among other things, "promote enforcement of all health and environmental statutes in areas with minority populations and low-income populations" and "ensure greater public participation." The May 1, 2013 EPA document *Draft Technical Guidance for Assessing Environmental Justice in Regulatory Analysis* addresses the executive order, focusing on rulemaking activities.

Per Figure 5-1, there are areas with minority populations and low-income populations in the vicinity of MIT. This application will assist MassDEP in promoting enforcement of the applicable health & environmental statutes in these areas, specifically the NAAQS. The air quality dispersion modeling analysis in Appendix A documents there will be no disproportionately high and adverse human health or environmental effects of the project on areas with minority populations and low-income populations.

MIT will work with MassDEP to identify opportunities to ensure greater public participation through the review process. MIT expects that will include use of alternative media outlets such as community or ethnic newspapers, use of alternative information repositories, translation of materials, and interpretation services at public meetings.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PORTLAND STREET
ALBANY STREET
VASSAR STREET
New Stack
New Turbine Building
5-Mile Radius
Project Site
WAKEFIELD
STONEHAM
MELR
MALDEN
MEDFORD
ARLINGTON
REVERE
EVERETT
CHELSEA
BELMONT
SOMERVILLE
CAMBRIDGE
WATERTOWN
WINTHROP
NEWTON
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APPENDIX A

Air Quality Dispersion Modeling Analysis

New 44 MW CoGen Project

PSD Air Quality Modeling Report

Massachusetts Institute of Technology

Submitted to:

Massachusetts Department of Environmental Protection
Bureau of Waste Prevention
One Winter Street
Boston, Massachusetts 02108

Prepared for:

MIT Department of Facilities
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December, 2015

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A-1. INTRODUCTION

The Massachusetts Institute of Technology (MIT) is located on 168 acres that extend more than a mile along the Cambridge side of the Charles River Basin. The MIT Central Utilities Plant (CUP) has been designed to provide near 100% reliability through maintaining standby units at all times, as the heat and electrical power generated is used to maintain critical research facilities, laboratories, classrooms and dormitories. The CUP provides electricity, steam heat, and chilled water to more than 100 MIT buildings.

MIT has retained Epsilon Associates Inc. (Epsilon) of Maynard, Massachusetts to perform an air quality modeling analysis in support of the air permit application for its proposed development of two nominal 23 MW Combustion Turbines (CT) with supplemental gas fired (134 MMBTU/hr HHV) heat recovery steam generators (HRSG) and a 2 MW cold start ULSD fired emergency engine. The project is to be located in an addition to Building 42 in an existing parking lot along Albany Street.

The CoGen Project is a major modification of an existing major source, subject to the requirement to obtain a Prevention of Significant Deterioration (PSD) permit. The installation of the new CoGen will create a significant emissions increase in potential direct CO_2, PM_{10} and $PM_{2.5}$ emissions.

This report describes the air quality modeling analysis for PM_{10} and $PM_{2.5}$ performed in support of the PSD Application. The air quality analyses described in this report demonstrate that the proposed project will not violate the National Ambient Air Quality Standards (NAAQS), PSD increments, and other applicable federal regulations.

The remainder of this report is organized in five sections. Section A-2 describes the federal and state air quality regulations applicable to the modeling analysis and presents the applicable air quality standards. Section A-3 provides a detailed description of the proposed Project including the design configuration, source data and the urban/rural determination for modeling, background air quality data, and the Good Engineering Practice (GEP) stack height analysis. Section A-4 describes the air quality modeling methodology. Section A-5 describes the modeling results. Finally, Section A-6 lists the reference documents used in compiling this modeling report.

A-2. REGULATORY REQUIREMENTS

The MIT CUP is an existing major stationary source per 40 CFR 52.21(b)(1)(i)(b). The installation of the new CoGen will create a significant emissions increase in potential direct CO_2, PM_{10} and $PM_{2.5}$ emissions per 40 CFR 52.21(b)(23)(i). Therefore, the CT installation is a major modification of an existing major source, subject to the requirement to obtain a Prevention of Significant Deterioration (PSD) permit. The Project is also subject to the MassDEP Plan Approval and Emission Limitations requirements under the MassDEP regulations at 310 CMR 7.02 but is not subject to 310 CMR 7.00: Appendix A Emission Offsets and Nonattainment Review.

MassDEP administers both the nonattainment New Source Review (NSR) program and the attainment NSR PSD program under delegation from EPA. The PSD program delegation is in accordance with the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and EPA which states that MassDEP agrees to implement and enforce the federal PSD regulations as found in 40 CFR 52.21.

A-2.1 Applicable Air Quality Standards, Significant Emission Rates, Significant Impact Levels, and PSD Increments

Table A-1 shows the estimated future potential emissions from the proposed CT project and the significant emission rates that trigger the applicable requirements. Potential emission rates are estimated based on performance data from the GE LM2500 provided by Vanderweil and proposed Best Available Control Technology (BACT) emission limits. These annual potential to emit estimates are based on the maximum permitted emission rate assuming two units with 168 hrs/yr (7 days) burning ultra-low sulfur diesel (ULSD) and use of natural gas for the turbines and duct burners on the HRSGs as necessary to meet the annual potential emission limits.

Table A-1. Project Future Potential Emissions vs. Significant Emission Rates

Pollutant	Estimated Potential Emission Rates (tpy)	Significant Emission Rate (tpy)	Significant? PSD Review Applies
NO_x	32.3	40	No
CO	22.4	100	No
PM_{10}	62.0	15	Yes
$PM_{2.5}$	62.0	10	Yes
SO_2	8.7	40	No
VOC	39.2	40	No
CO_2E	401,296	75,000	Yes

The CT project is subject to the PSD program for Particulate Matter and Greenhouse Gases (CO_{2e}), and must apply for and obtain a PSD Permit that meets regulatory requirements including:

- Best Available Control Technology (BACT) requiring sources to minimize emissions to the greatest extent practical;
- An ambient air quality analysis to ensure all the emission increases do not cause or contribute to a violation of any applicable PSD increments or NAAQS;
- An additional impact analysis to determine direct and indirect effects of the proposed source on industrial growth in the area, soil, vegetation and visibility; and
- Public comment including an opportunity for a public hearing.

All of MA is designated as moderate non-attainment for the 8-hr ozone standard and attainment for all other criteria pollutants. The project does not trigger Non-attainment New Source Review (NNSR) because potential NOx emissions are below the 310 CMR 7.00: Appendix A major source modification threshold of 25 tpy due to the non-attainment status for ozone. MIT is not currently a major source of VOC. After installation of the project, MIT campus wide emissions will remain below 50 tpy, the major source threshold for an existing minor source of VOC.

The facility cannot cause or contribute to the violation of any National or Massachusetts State Ambient Air Quality Standard (NAAQS or MAAQS) or consume more than the available PSD increment for pollutants subject to the PSD requirement. Air quality dispersion modeling is used to demonstrate compliance with these thresholds.

PSD increment is tracked on a county wide basis in Massachusetts. The PSD regulations define “minor source baseline date” at 40 CFR 52.21(b)(14)(ii) as “the earliest date after the trigger date on which… a major modification subject to 40 CFR 52.21… submits a complete application”. Therefore, if the minor source baseline date has not been established for the baseline area (Middlesex County), this application will establish the baseline date when it is determined to be complete. EPA has established increment standards for PM_{10} and $PM_{2.5}$. Based on consultation with MassDEP the PM_{10} minor source baseline date was triggered on September 10^{th}, 2001 by a PSD application from Kendall Station.

Table A-2 shows the NAAQS, significant impact levels (SILs), and PSD increments applicable at this time. The SILs are numerical values that represent thresholds of insignificant, i.e., de minimis, modeled source impacts. As shown in Table A-2, the SILs are small fractions of the health protective NAAQS. For new sources that exceed these levels, the air quality impact analysis is required to include the new source, existing interactive sources and measured background levels. If the maximum predicted impacts of a pollutant due to a proposed emission increase from the existing facility are below the applicable SILs, the predicted emissions from the proposed modification are considered to be in compliance with the NAAQS and PSD increments for that pollutant.

Table A-2. National and Massachusetts Ambient Air Quality Standards, SILS, & PSD Increments

Pollutant	Averaging Period	NAAQS/MAAQS ($\mu g/m^3$)		Significant Impact Level ($\mu g/m^3$)	PSD Increments ($\mu g/m^3$)	
		Primary	Secondary		Class I	Class II
NO_2	Annual (1)	100	Same	1	2.5	25
	1-hour (2)	188	None	7.5	None	None
SO_2	Annual (1)	80	None	1	2	20
	24-hour (3)	365	None	5	5	91
	3-hour (3)	None	1300	25	25	512
	1-hour (4)	196	None	7.8	None	None
$PM_{2.5}$	Annual (1)	12	15	0.3	1	4
	24-hour (5)	35	Same	1.2	2	9
PM_{10}	24-hour (6)	150	Same	5	8	30
CO	8-hour (3)	10,000	Same	500	None	None
	1-hour (3)	40,000	Same	2,000	None	None
Ozone	8-hour (7)	147	Same	N/A	None	None
Pb	3-month (1)	1.5	Same	N/A	None	None

(1) Not to be exceeded

(2) 98th percentile of 1-hour daily maximum concentrations, averaged over 3 years

(3) Not to be exceeded more than once per year.

(4) 99th percentile of 1-hour daily maximum concentrations, averaged over 3 years

(5) 98th percentile, averaged over 3 years

(6) Not to be exceeded more than once per year on average over 3 years

(7) Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years

Note that in January 2013, the Circuit Court decision[1] vacating the $PM_{2.5}$ significant monitoring concentration does not preclude the use of the SILs for $PM_{2.5}$ entirely, but requires monitoring data be presented. If the monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the $PM_{2.5}$ monitored background concentration in the area is greater than the EPA $PM_{2.5}$ SIL value, then EPA believes it would be sufficient to conclude that a proposed source with a $PM_{2.5}$ impact below the $PM_{2.5}$ SIL value will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and to forego a more comprehensive modeling analysis for $PM_{2.5}$.

1 http://www.epa.gov/nsr/documents/20130304qa.pdf.

For the source impact analysis for the $PM_{2.5}$ NAAQS, the analysis should address impacts of direct $PM_{2.5}$ emissions and/or $PM_{2.5}$ precursor emissions based upon the total amount of these emissions as compared to the respective significant emission rates (SERs).

For the MIT Cogen project, it is deemed that it is not necessary to address the secondary formation of $PM_{2.5}$ in the NAAQS analysis. Based on Table III-1 in the EPA $PM_{2.5}$ guidance (May, 2014), the MIT Cogen project falls into Case 2 which does not include a secondary impacts approach, Case 2 is defined as the situation where the direct $PM_{2.5}$ emissions are greater than 10 tpy and the precursor emissions of NO_x and SO_2 are individually less than 40 tpy.

A-3. PROJECT DESCRIPTION

A-3.1 Project Location

The Central Utility Plant (CUP) is housed in Building 42 (N16, N16A and 43) which is located between Vassar Street and Albany Street in Cambridge, MA. The new turbines would be housed in an addition to Building 42 to be built in an existing parking lot along Albany Street between the cooling towers and an existing parking garage. The addition to the existing building would be approximately 224′ x 118′ by 63′ above ground level (AGL) with two approximately 165′ high AGL flues centrally co-located in a common stack structure. There will be a flue for each turbine vented through its respective Heat Recovery Steam Generator (HRSG). The emergency engine stack will also be located on the southwest corner of the roof approximately 96.5′ high AGL. An aerial locus of the area around the new project is shown in Figure A-1. The proposed new turbine building and the proposed site for the new turbine stacks and new 2 MW engine stack are shown.

A-3.2 Facility Description

The MIT CUP has multiple units comprising the existing power plant. The existing equipment operating at the CUP is listed in Table A-3.

Table A-3 Key Existing Equipment Operating at the MIT CUP

Turbine #1	ABB GT10 (GT-42-1A) and Heat Recovery Steam Generator #1 (HRSG-42-1B) (collectively the existing Cogeneration Unit)
Boiler #3	Wickes 2 drum type R dual fuel (BLR-42-3)
Boiler #4	Wickes 2 drum type R dual fuel (BLR-42-4)
Boiler #5	Riley type VP dual fuel (BLR-42-5)
Generator #01	Emergency Diesel Generator Caterpillar #3516B 2MW (DG-42-6)
Boiler #7	Indeck Dual Fuel BLR-42-7
Boiler #9	Boiler rated at 125 MMBtu/hr firing natural gas with Ultra Low Sulfur Diesel (ULSD) backup
Cooling Towers	Wet mechanical towers #1,2,3,4,5,6,7,8,9,10

Emissions from Boilers #3, #4 and #5 are vented out the brick stack on the roof of the CUP. The existing turbine #1 stack and the emergency generator stack are also located on the roof of the CUP. Boilers #7 and #9 are located adjacent to Building N16A at 60 Albany Street, across the railroad tracks from the main CUP building. Exhaust from both Boiler #7 and Boiler #9 are combined and vent through a common stack.

The proposed Project will consist of adding two combustion turbines CT with HRSG's and ancillary equipment for a nominal total output of ~46 MW. The project layout is shown in Figure A-2. The two units will burn primarily natural gas with ultra-low sulfur distillate (ULSD) oil as an emergency back-up fuel supply for up to 7 days/year. Exhaust from the new turbines will be vented through its own approximately 165 foot tall 7' diameter flue, i.e., one flue for each turbine. MIT will be retiring some of the existing wet mechanical cooling towers and adding three new ones. Tower #1, 2, 3, 4, 5, and 6 will be taken out of service while Towers #11, 12, and 13 will be added. Towers #7, 8, 9, and 10 will remain. Figure A-3 shows the locations of the existing cooling towers, and the cooling tower configuration once the project is built is shown in Figure A-4.

In conjunction with the proposed project MIT plans to retire the existing 20 MW and associated duct burner (GT-42-1A and HRSG-42-1B). MIT also intends to reduce ULSD firing for existing Boilers 7 & 9 from 720 hours per year to 168 hours per year (7 days) and increase the gas-fired operating hours for these boilers to allow for year-round operation. Lastly, MIT intends to remove the residual (No. 6) oil firing for the existing Boilers 3, 4, & 5 (BLR-42-3, BLR-42-4, BLR-42-5). These boilers will be capable of firing ULSD in emergencies (with a burner tip change to allow firing the cleaner fuel).

Installation of the new CT units will be staggered, such that there will be a period of several months when one new CT unit will operate before the existing CT unit and associated duct burner is removed. The existing CT unit will fire natural gas only during the transitional period, and will be capable of firing ULSD in emergencies.

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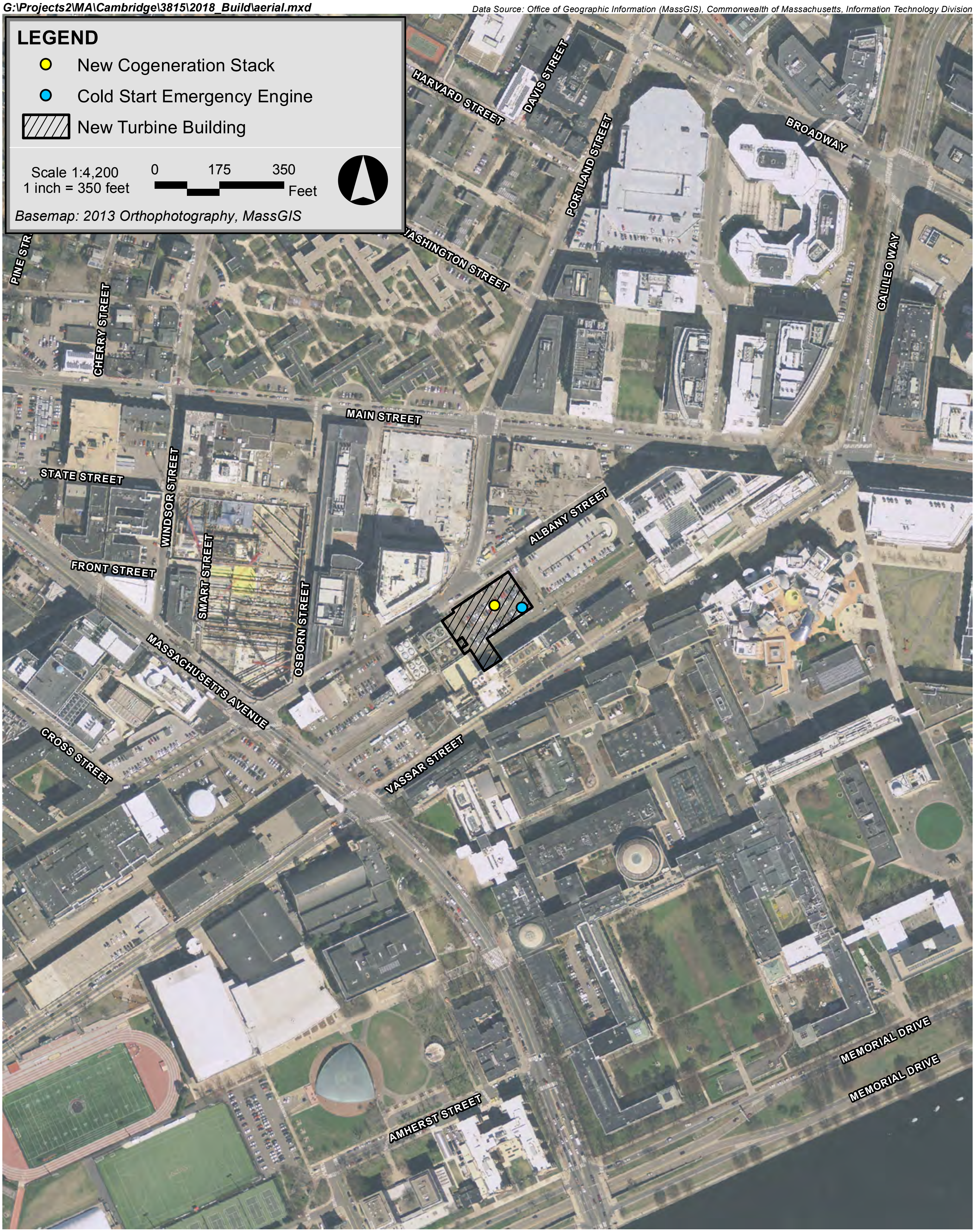
Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project **Cambridge, Massachusetts**

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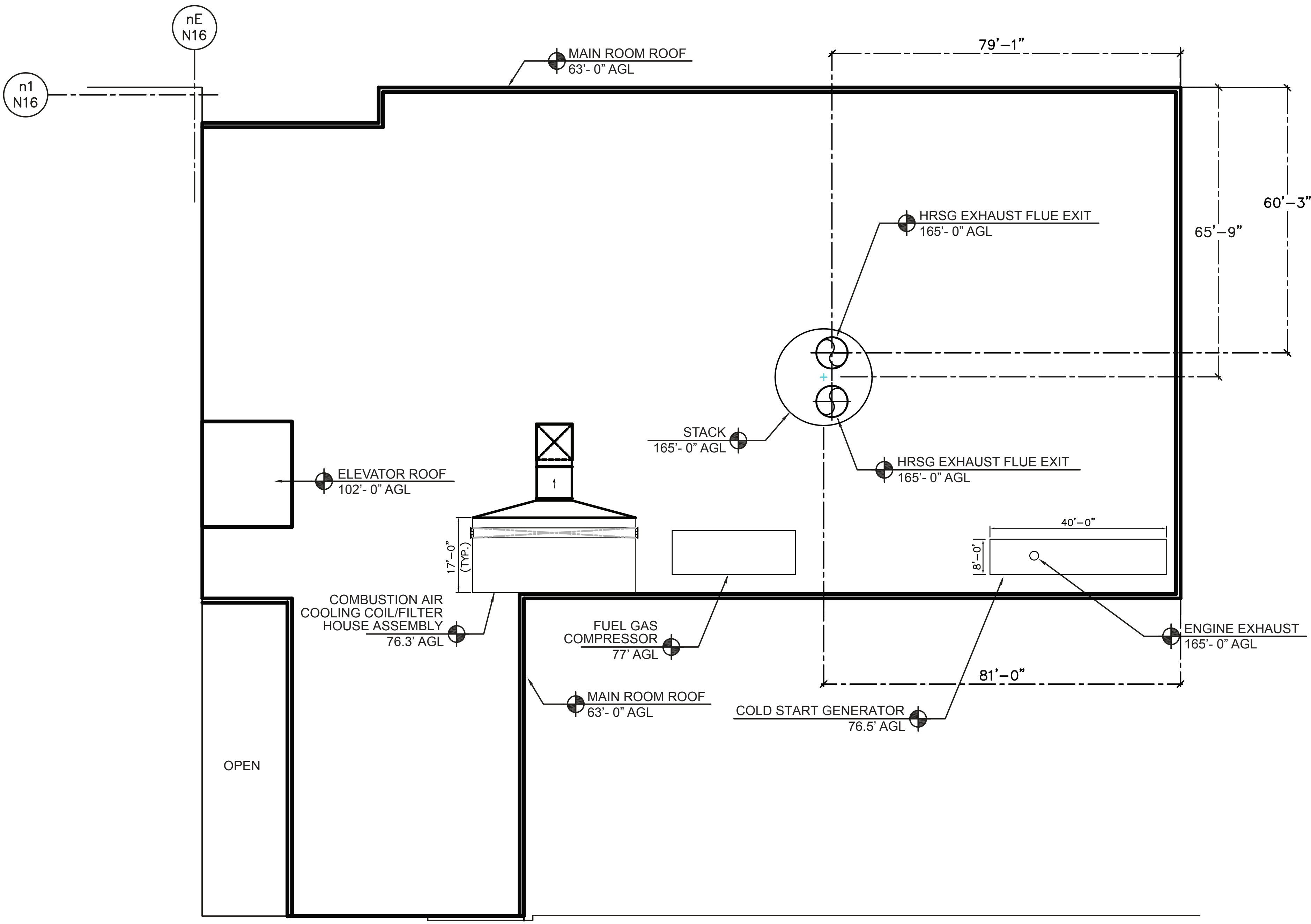
Figure A-1

Aerial Locus Map



MIT Cogeneration Project **Cambridge, Massachusetts**

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Figure A-2

Project Layout/Site Plan

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Figure A-3

Existing Cooling Tower Locations

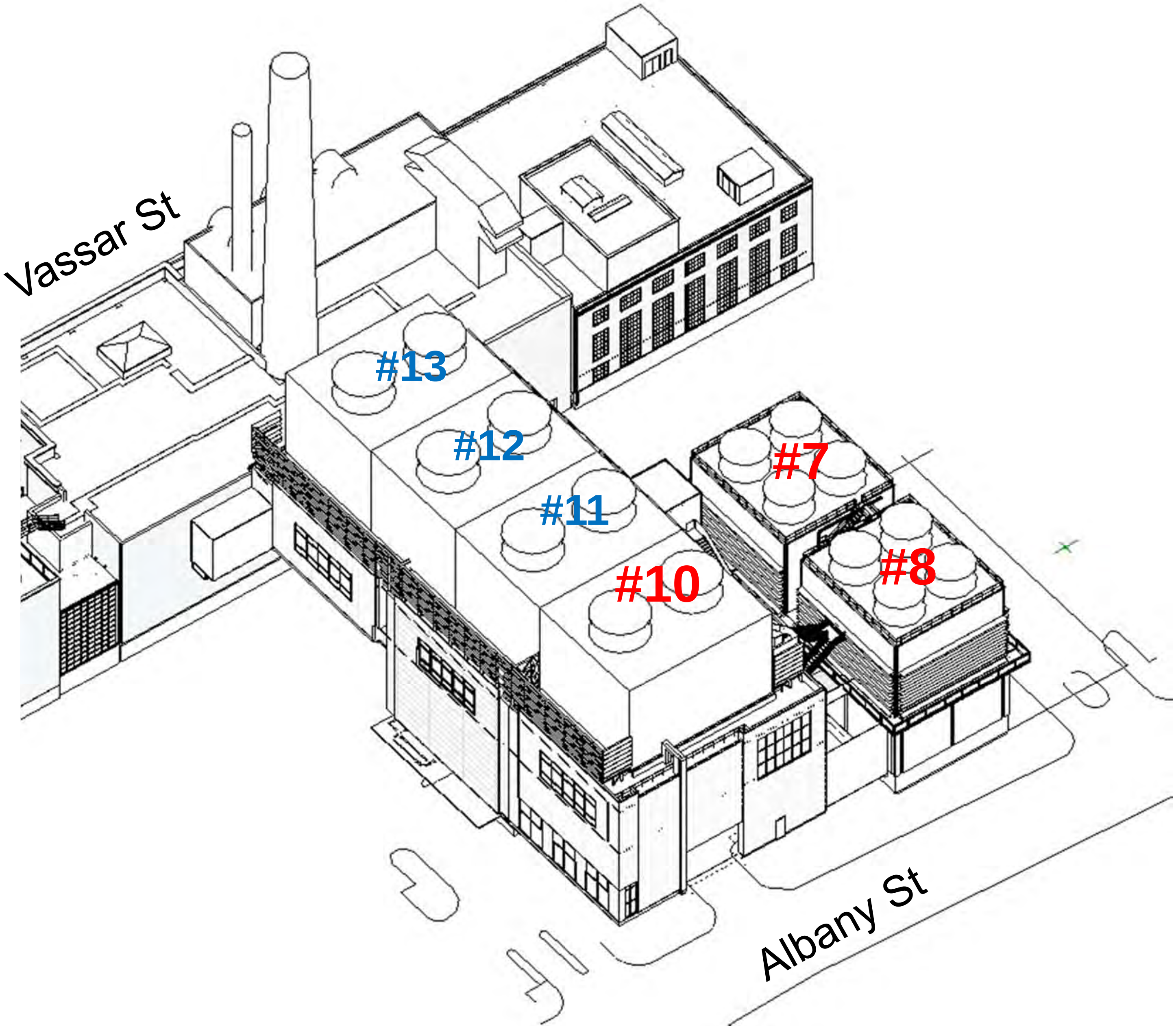

Figure A-4

Final Build Cooling Tower Locations (existing-red, new-blue)

A-3.3 Source Data

In addition to modeling the impacts from the new units, the Project includes modeling of the existing units at the MIT CUP to determine full facility impacts. Some modifications are proposed for the operations of the existing units while operating coincident with the new turbines, including new restrictions are proposed on oil firing for existing Boilers 3, 4&5, 7&9. A range of potential operating loads (25%, 50%, 75%, and 100%) were modeled for the new units using a range of ambient temperatures (0 and 60 F). The parameters for each operating case are listed in Attachment A. The proposed turbines may burn natural gas with a backup fuel of ULSD. Both options over a range of loads and ambient temperatures were modeled to determine the case resulting in the highest air quality impact of each pollutant. The duct burners will fire gas only but can be used during gas or oil firing of the turbines. The worst case scenario is then modeled with the existing facility to demonstrate compliance with the NAAQS. The cooling tower emissions are below the MassDEP threshold for inclusion in air quality modeling, however because this is a PSD project for $PM_{2.5}$ and PM_{10}, the cooling towers are included in the modeling analysis.

Two operational configurations shown in Table A-4 have been modeled, i.e. one new turbine operating through the HRSG and 2 new turbines operating through their HRSG's. For the one turbine case, both Turbine 1 and Turbine 2 stacks were modeled in the load analysis and the worst case location was carried throughout the modeling. When modeling the case of the two new turbines operating through their HRSG's their plumes have been merged using an effective diameter to represent the area of the two individual flues.

Table A-4. Operational Scenarios

Scenario	New Turbine Configuration	2MW Engine	Additional MIT Sources Operating
1	1 Turbine with Duct Burner/HRSG	included	Turbine#1; Boilers #3,4,5; Boilers #7,9; Generator #01 Cooling Towers#7,8, 9, 10,11,12,13
2	2 Turbines with Duct Burner /HRSG	included	Boilers #3,4,5; Boilers #7,9; Generator #01 Cooling Towers#7,8,9,10,11,12,13

Table A-5 summarizes the physical stack parameters for the new stacks and cooling towers. Note that the cooling towers have multiple cells, denoted with a letter in the naming convention. The UTM coordinates are located in zone 19.

Table A-5. Physical Stack Characteristics for the New Sources

Stack	UTM E (m)	UTM N (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)
Turbine/HRSG 1	327596.60	4692061.12	2.73	50.29	2.13
Turbine/HRSG 2	327598.56	4692058.29	2.73	50.29	2.13
Merged Turbine Stack	327597.12	4692059.34	2.73	50.29	3.02
2 MW Cold Start Engine	327615.92	4692057.64	2.73	29.41	0.71
Cooling Tower 11A	327552.38	4692017.83	2.73	29.69	6.78
Cooling Tower 11B	327545.00	4692012.54	2.73	29.69	6.78
Cooling Tower 12A	327558.64	4692008.53	2.73	29.69	6.78
Cooling Tower 12B	327550.46	4692003.71	2.73	29.69	6.78
Cooling Tower 13A	327563.45	4692001.47	2.73	29.69	6.78
Cooling Tower 13B	327555.91	4691996.01	2.73	29.69	6.78

Oil is intended to be used only in the case of gas interruption (curtailment, gas supply emergency, or any required testing), however it is still included in the modeling. The source parameters and emission rates are shown in Tables A-6 and A-7for the worst case load conditions for each pollutant and averaging time. The source parameters and emission rates for the 2 MW cold start emergency engine and new cooling towers are provided in Table A-8.

Table A-6. New Turbine Source Characteristics and Emission Rates for 1 Turbine with Duct Burner/HRSG (Operational Scenario 1)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (ºK)	Emission Rate (g/s)	Fuel	Load Condition
PM_{10}	24-Hour	22.5	380.4	1.59	ULSD	Case I.g: 0° F, Turbine #1, 100% Load, Duct Burner On
$PM_{2.5}$	24-Hour	22.5	380.4	1.59	ULSD	Case I.g: 0° F, Turbine #1, 100% Load, Duct Burner On
	Annual	17.7	355.4	0.97[1]	NG	Case I.Annual: 60° F, Turbine #1 75% Load, Duct Burner On

[1] Emission rate reflects the potential emission limit specified in the air plan approval application.

Table A-7. New Turbine Source Characteristics and Emission Rates for 2 Turbines with Duct Burners/HRSGs (Operational Scenario 2)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (ºK)	Emission Rate[1] (g/s)	Fuel	Load Condition[2]
PM_{10}	24-Hour	18.9	380.4	2.56	ULSD	Case 2.h: 0°F, Turbines 1&2, 75% Load, Duct Burner On
$PM_{2.5}$	24-Hour	18.9	380.4	2.56	ULSD	Case 2.h: 0°F, Turbines 1&2, 75% Load, Duct Burner On
	Annual	17.7	355.4	1.94[3]	NG	Case 2.Annual, Turbines 1&2, 75% Load, Duct Burner On

[1] Emission rate is the total for both turbines.

[2] Condition is modeled as a merged flue for Turbine 1 and 2.

[3] Emission rate reflects the potential emission limit specified in the air plan approval application.

Table A-8. New 2 MW Engine and Cooling Tower Source Characteristics and Emission Rates

Source	Exit Temp (K)	Exit Velocity (m/s)	Short Term/ Annual	PM_{10}/ $PM_{2.5}$ (g/s)
2MW Cold Start Emergency Engine	672.7	18.15	Short-Term	1.68E-2[1]
			Annual	1.76E-3[2]
Cooling Towers #11, 12, 13 per cell (6)	298.7	8.0	N/A	4.40E-3

[1] Assumes cold start emergency engine will not operate more than 8 hours in a single day.

[2] Annualized emissions assuming a maximum of 300 hours per year.

MIT Existing Facility Sources

As part of the permitting effort, MassDEP has the option to require demonstration that the full MIT power facility will comply with the NAAQS. Boiler 9 was recently permitted (2011) and full facility compliance was achieved then. However since then there have been new nearby structures built or proposed. This modeling analysis takes those new structures into account. In addition, MIT is proposing several operational changes to existing sources including: removing the residual (No. 6) oil firing for existing Boilers 3, 4, and 5, the boilers will be capable of firing ULSD in emergencies (with a burner tip change to allow firing the cleaner fuel); removing the ULSD firing for existing Boilers 7 and 9 (maintaining ULSD firing capability for emergencies) and increasing (gas-fired) operating hours for Boilers 7 and 9 to allow year-round operation. The source parameters and emission rates used for this analysis and are presented in Tables A-9, A-10 and A-11.

Table A-9. Physical Stack Characteristics for the MIT Existing Sources

Stack	UTM E (m)	UTM N (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)
Boilers 7 & 9 Stack	327510.2	4692006.1	2.73	35.05	1.68
Boilers 3,4,5	327570.3	4691983.3	2.74	53.95	3.35
Turbine #1	327575.2	4691973.9	2.74	36.58	1.83
Generator #01	327595.7	4691984.2	2.74	19.43	0.41
Cooling Tower 1A	327604.2	4692009.7	2.73	18.15	4.42
Cooling Tower 1B	327609.4	4692013.8	2.73	18.15	4.42
Cooling Tower 2A	327614.7	4692016.6	2.73	18.15	4.42
Cooling Tower 2B	327619.5	4692020.0	2.73	18.15	4.42
Cooling Tower 3A	327545.7	4692010.4	2.73	20.57	6.16
Cooling Tower 3B	327541.6	4692016.3	2.73	20.57	6.16
Cooling Tower 4A	327553.7	4692015.4	2.73	20.57	6.16
Cooling Tower 4B	327549.8	4692021.9	2.73	20.57	6.16
Cooling Tower 5	327571.0	4691990.9	2.73	17.37	2.52
Cooling Tower 6	327576.8	4691994.7	2.73	17.37	2.52
Cooling Tower 7A	327522.7	4691998.6	2.73	20.57	4.94
Cooling Tower 7B	327528.5	4692002.2	2.73	20.57	4.94
Cooling Tower 7C	327518.9	4692004.9	2.73	20.57	4.94
Cooling Tower 7D	327523.9	4692008.3	2.73	20.57	4.94
Cooling Tower 8A	327513.3	4692013.3	2.73	20.57	5.03
Cooling Tower 8B	327518.5	4692016.4	2.73	20.57	5.03
Cooling Tower 8C	327514.5	4692022.9	2.73	20.57	5.03
Cooling Tower 8D	327509.3	4692019.3	2.73	20.57	5.03
Cooling Tower 9A	327501.1	4691981.7	2.73	10.03	3.96

Table A-9. Physical Stack Characteristics for the MIT Existing Sources (Continued)

Stack	UTM E (m)	UTM N (m)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)
Cooling Tower 9B	327497.6	4691980.0	2.73	10.03	3.96
Cooling Tower 9C	327493.8	4691976.7	2.73	10.03	3.96
Cooling Tower 9D	327490.3	4691975.0	2.73	10.03	3.96
Cooling Tower 10A	327542.2	4692034.4	2.73	30.21	6.78
Cooling Tower 10B	327534.2	4692027.3	2.73	30.21	6.78

Table A-10 Worst-case Operating Conditions for Existing MIT Stacks by Pollutant and Averaging Period

Pollutant	Averaging Period	Boiler 7/9 Stack	Boilers #3,4,5	Turbine
PM_{10}	Short-term	Boiler #9 alone full load	Full load	Full load
$PM_{2.5}$	Short-term	Boilers #7 and #9	Full load	Full load
	Annual	Boiler #9 alone full load	Minimum Load	Full load

Table A-11. Existing MIT Source Characteristics and Emission Rates

Stack	Operating Condition	Short-Term/ Annual	Exit Temp (K)	Exit Velocity (m/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)
Boilers 7 & 9	Boilers 7 & 9 (full load)	Short-Term	473.7	17.68	0.83	0.83
		Annual			-	0.29
	Boiler 9 only (full load)	Short-Term	430.4	8.06	0.45	0.45
		Annual			-	0.164
Boilers 3,4,5	Full Load	Short-Term	430.4	5.91	2.62	2.62
		Annual			-	1.45
	Minimum Load	Short-Term	405.4	0.73	0.32	0.32
		Annual			-	0.179
Turbine #1	Full Load	Short-Term	405.4	35.79	1.756	1.756
		Annual			-	0.63
Generator	Full Load	Short-Term	790.3	61.94	9.58E-2	9.58E-2
		Annual			-	3.28E-3

Table A-11. Existing MIT Source Characteristics and Emission Rates (Continued)

Stack	Operating Condition	Short-Term/ Annual	Exit Temp (K)	Exit Velocity (m/s)	PM_{10} (g/s)	$PM_{2.5}$ (g/s)
Cooling Tower 1 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3
Cooling Tower 2 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3
Cooling Tower 3 per cell (2)	N/A	N/A	298.7	8.0	5.86E-3	5.86E-3
Cooling Tower 4 per cell (2)	N/A	N/A	298.7	8.0	5.18E-3	5.18E-3
Cooling Tower 5	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3
Cooling Tower 6	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3
Cooling Tower 7 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3
Cooling Tower 8 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3
Cooling Tower 9 per cell (4)	N/A	N/A	298.7	8.0	2.65E-3	2.65E-3
Cooling Tower 10 per cell (2)	N/A	N/A	298.7	8.0	4.40E-3	4.40E-3

A-3.4 Urban/Rural Analysis

The USGS topographic quadrangle maps in the vicinity of the Project were used to determine whether the land-use pattern in the environs of MIT is urban or rural for modeling purposes. The EPA recommended procedure in *The Guideline on Air Quality Models* (EPA, 2005) was followed to determine urban/rural classification using the Auer (1977) land use technique. The land use within the total area circumscribed by a 3 kilometer radius circle around the MIT CUP has been classified using the meteorological land use typing scheme shown in Table A-12. If the land use types I1, I2, C1, R2 and R3 account for 50 percent or more of the area, then urban dispersion coefficients should be used. Figure A-5 shows the 3 km radius around the project site. Observation of USGS topographic map shows that the area within a 3 kilometer radius of the MIT CUP is a predominantly urban setting. Therefore urban dispersion coefficients were used in the AERMOD modeling.

Table A-12. Identification and Classification of Land Use

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

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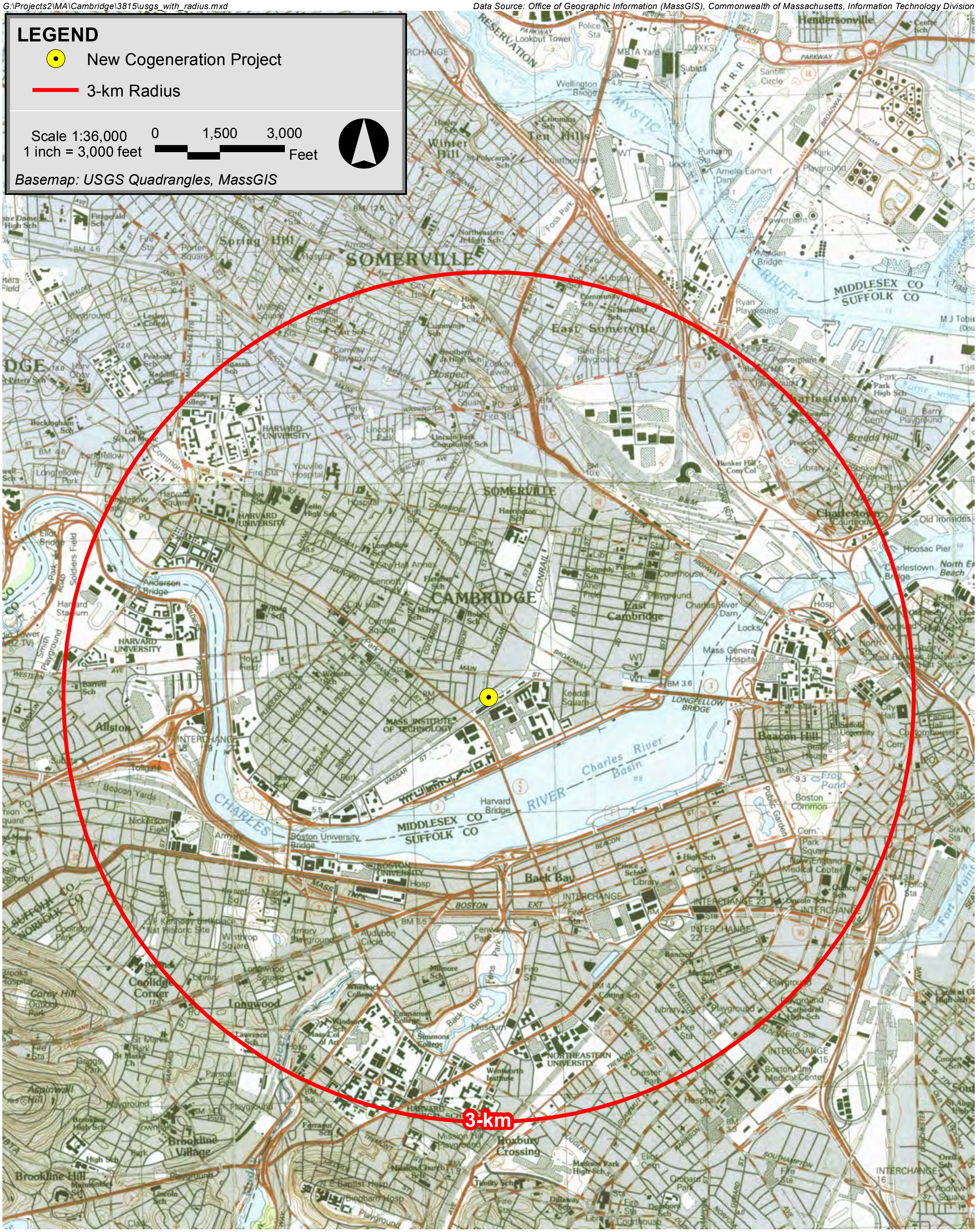
Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project **Cambridge, Massachusetts**

Figure A-5

USGS Topographic Map with 3-km Radius

A-3.5 Background Air Quality Data

Modeled concentrations due to emissions from the Project are added to ambient background concentrations to obtain total concentrations. These total concentrations were compared to the NAAQS. To estimate background pollutant levels representative of the area, the most recent air quality monitor data reports published by MassDEP were obtained for 2012 through 2014. Background concentrations were determined from the most representative available monitoring stations to the MIT CUP. The most representative monitoring site is also the closest monitoring site, located at Kenmore Square in Boston, MA, approximately 0.9 miles from the MIT CUP. The urban environment surrounding the monitor in Boston is similar to the urban environment in Cambridge near the MIT CUP. Both PM_{10}, and $PM_{2.5}$ are monitored at Kenmore Square. A summary of the background air quality concentrations based on the 2012-2014 data are presented in Table A-13. For the short-term averaging periods, the form of the standard value is used, and the highest monitored value is used for annual averages.

Table A-13. Observed Ambient Air Quality Concentrations and Selected Background Levels

Pollutant	Averaging Period	2012	2013	2014	Background Level	NAAQS
PM_{10} ($\mu g/m^3$)	24-Hour	28.0	50.0	53.0	53.0	150
$PM_{2.5}$ ($\mu g/m^3$)	Annual[1]	9.0	8.0	6.0	7.7	12

[1] Background level for Annual $PM_{2.5}$ is the average concentration of three years.

For this analysis some level of temporal pairing of modeled and monitoring data was used. 24-hour $PM_{2.5}$ is not represented in Table A-13 because daily background values of $PM_{2.5}$ were used in a post-processing step for the concurrent period of modeling 2010-2014.

There are several Federal Reference Method (FRM) $PM_{2.5}$ monitoring sites in the vicinity of MIT. The closest monitor is located in Kenmore Square. The next closest $PM_{2.5}$ monitor is City Square (1.8 miles), followed by the North Street monitor (2.0 miles), and the Harrison Avenue monitor (2.3 miles). The $PM_{2.5}$ monitoring data set was obtained from MassDEP for the years 2010-2014 to match the period of meteorological data. All of these sites are urban locations and are representative of the Cambridge environment near the MIT CUP. Since the monitoring at Kenmore Square is conducted approximately every third day, there are a large number of days with no data at this station. To estimate daily background pollutant levels representative of the area, if the Kenmore Square data was not available on a given day, the data measured from the next closest monitor with data for that day was substituted. If there is no measured data at any of the stations on that given day, then the higher of the measurements before or after the given day at Kenmore Square was substituted. The resulting daily background data for each day of the 5 years modeled was added to the 24-hour modeled impact at each receptor.

Note that MassDEP installed a number of Beta Attenuation Monitors (BAMs) semi-continuous samplers for $PM_{2.5}$. One such monitoring location is located at North Street, however the 5-year period (2010-2014) does not appear to have reliable data which can be used for a regulatory modeling analysis. Epsilon has used the EPA $PM_{2.5}$ Continuous Monitor Comparability Assessment Tool for the data collected during the 2010-2014 period at North Street. Following the guidance provided in Subpart C to 40 CFR Part 53 (EPA, 2012), Epsilon has determined that the concentration range did not meet the correlation criteria used in approving continuous $PM_{2.5}$ FEMs. The data does show that the correlation criteria are met for reporting of the Air Quality Index, but not for comparisons to the NAAQS. In addition, the data obtained from the EPA AQS Data Mart at the North Street sit has the parameter code listed as '88502' which is defined as "Valid data that does not reasonable match the FRM with or without correction, but not to be used in NAAQS decisions." As such, Epsilon believes it is more appropriate to use the FRM data from Kenmore Square, which is the closest and most representative monitoring site to MIT and has prepared a daily $PM_{2.5}$ background file following the approach of using the FRM data described above.

A-3.5.1 Justification to use SILs

If the monitoring data shows that the difference between the NAAQS and the monitored background concentration in the area is greater than the EPA SIL value for that pollutant and averaging period, then EPA believes it would be sufficient to conclude that a proposed source with an impact below the SIL value will not cause or contribute to a violation of the NAAQS and to forego a more comprehensive modeling analysis for that pollutant for that averaging period. Table A-14 presents the difference between the NAAQS and the monitored background concentration, compared to the SILs. As shown in Table A-14, all averaging periods for each pollutant has a delta between the monitored value and the NAAQS which is greater than the respective SIL, therefore use of the SILs for PM_{10}, and $PM_{2.5}$ as de minimis levels is appropriate.

Table A-14. Comparison of the Difference between the Monitored Air Quality Concentrations and the NAAQS to the Significant Impact Levels

Pollutant	Averaging Period	Background Level ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Delta (NAAQS-Bkgrnd) ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
PM_{10}	24-Hour	53.0	150	97.0	5
$PM_{2.5}$	24-Hour	18.2	35	16.8	1.2
	Annual	7.7	12	4.3	0.3

A-3.6 Good Engineering Practice Stack Height Determination

The GEP stack height evaluation of the facility has been conducted in accordance with the EPA revised Guidelines for Determination of Good Engineering Practice Stack Height (EPA, 1985). The formula, as defined by the EPA guidelines, for the GEP stack height is:

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

where H_{GEP} = GEP stack height,

Hb = Height of adjacent or nearby structures,

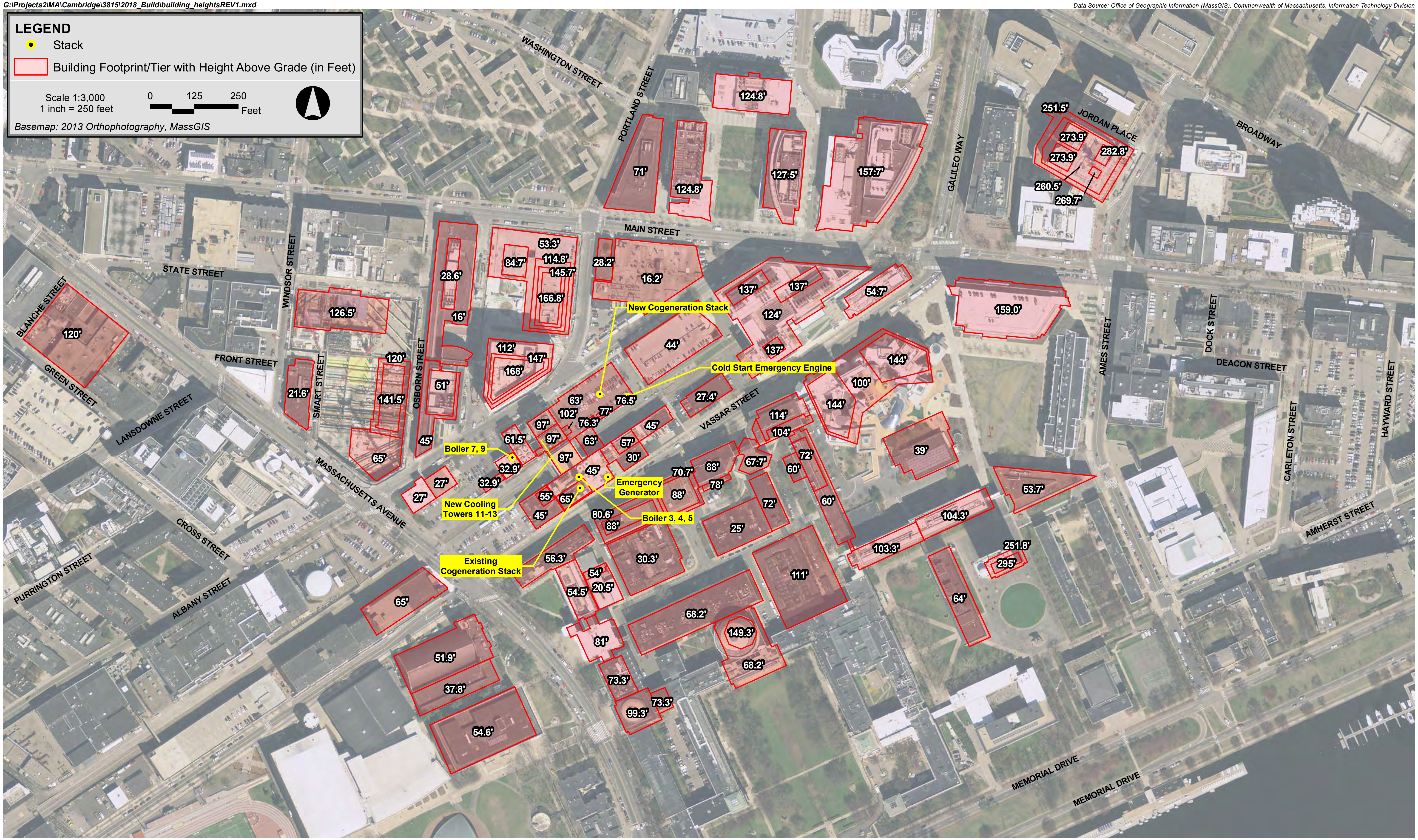
L = Lesser of height or maximum projected width of adjacent or nearby building, i.e., the critical dimension, and

Nearby = Within 5L of the stack from downwind (trailing edge) of the building.

A GEP analysis was conducted to determine the GEP formula stack height for each stack to account for potential downwash from nearby structures. The latest version of the EPA Building Profile Input Program (BPIP-Prime) was run for all stacks and buildings in the vicinity of the project to create the building parameter inputs to AERMOD. The new and proposed construction on Albany Street and Main Street (Novartis buildings) are included. A GEP height of 127 meters was calculated for each stack with the 50.8 meter tier of the new 610/650 Main Street building as the controlling structure for determining the GEP height. Figure A-6 shows the structure footprints and stack locations input into BPIP-Prime (heights are depicted in the figure). Each of the stacks modeled are below their GEP height and therefore exhaust emissions will experience the aerodynamic effects of downwash. Wind direction specific building parameters generated by BPIP-Prime were input into AERMOD to account for potential downwash from nearby structures in the dispersion calculations.

G:\Projects2\MA\Cambridge\3815\2018_Build\building_heightsREV1.mxd

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon ASSOCIATES INC.

Figure A-6

Building Footprints/Tiers and Heights Used in BPIP-Prime (Based on Anticipated Build-out by 2018)

A-4. AIR QUALITY IMPACT ANALYSES

The Project conducted comprehensive air quality modeling analyses to demonstrate that the proposed project's air quality impacts would be in compliance with all Federal requirements. The ambient pollutant concentrations associated with the Project are addressed in the detailed air quality analysis discussed in this section. The following analyses were included:

- Load Analysis for new turbines
- Modeling of PM_{10}, and $PM_{2.5}$ for comparison with the SILs
- Modeling of PM_{10}, and $PM_{2.5}$ for comparison with the NAAQS, including interactive source modeling
- Modeling of PM_{10}, and $PM_{2.5}$ for comparison with the PSD Increments
- VISCREEN modeling

Impacts of PM_{10}, and $PM_{2.5}$ emissions were modeled for comparison to ambient air quality standards. The modeling approach followed the guidance in the U.S. EPA Guideline on Air Quality Models (EPA, 2005) and the Massachusetts Modeling Guidance (MassDEP, 2011) to ensure that the ambient concentrations are protective of all applicable air quality standards.

In the New Source Review (NSR) Workshop Manual (EPA, 1990) the dispersion modeling analysis is separated into two distinct phases: 1) the preliminary analysis, and 2) a full impact analysis. In the preliminary analysis only the significant increase in potential emissions of a pollutant from a proposed new source or the significant net emissions increase of a pollutant from a proposed modification are modeled. The results of this analysis are used to determine:

- the worst-case stack parameters; and
- which criteria pollutants require a full impact analysis;
- the receptor locations to be used in the interactive modeling analysis (if necessary).

The EPA does not require a full impact analysis for a particular pollutant if the results of the preliminary analysis indicate the emissions from the proposed source or modification will not increase ambient concentrations by more than pollutant specific SILs (see Table A-2).

Per MassDEP Modeling Guidance for Significant Stationary Sources of Air Pollution (MassDEP, 2011), if impacts are below SILs, a compliance demonstration may still be required to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant.

A- 4.1 Modeling Methodology

The MIT CoGen project consists of the addition of two new combustion turbines and a 2 MW ULSD-fired cold start emergency engine at a new building along Albany Street, adjacent to the cooling towers. Also three new cooling towers will be built, replacing some of the existing cooling towers. AERMOD modeling for the each potential fuel burned at various ambient temperatures and load cases was performed for the new turbines to determine the worst-case impact for each of the potential Operational Scenarios listed in Table A-4.

The worst-case operating conditions for the new turbines were then modeled with the 2MW cold start emergency engine and the cooling towers to assess the PM_{10}, and $PM_{2.5}$ concentrations which are compared to the SILs presented earlier in Table A-2.

If the maximum predicted impacts of a pollutant due to the emission increase from the existing facility are below the applicable SILs, the predicted emissions from the proposed modifications are considered to be in compliance with the NAAQS for that pollutant. However a compliance demonstration was conducted to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant (MassDEP, 2011). The appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS.

If the maximum predicted impacts of a pollutant due to the emission increase from the existing facility are at or above the applicable SILs, and there are nearby sources of that pollutant that could significantly interact with emissions from the facility's proposed modification, the predicted air quality impacts from the existing facility as modified along with the predicted impacts from nearby significant sources should be added to the representative background and compared to the NAAQS for that pollutant (MassDEP, 2011).

EPA (2013) has adopted guidance regarding secondary $PM_{2.5}$ formation in modeling analyses.

- Case 1: If $PM_{2.5}$ emissions < 10 tpy and NOx & SO_2 emissions < 40 tpy, then no $PM_{2.5}$ compliance demonstration is required.

- Case 2: If $PM_{2.5}$ emissions > 10 tpy and NOx & SO_2 emissions < 40 tpy, then $PM_{2.5}$ compliance demonstration is required for direct $PM_{2.5}$ emission based on dispersion modeling, but no analysis of precursor emissions from the project source is necessary.

- Case 3: If $PM_{2.5}$ emissions > 10 tpy and NOx &/or SO_2 emissions > 40 tpy, then $PM_{2.5}$ compliance demonstration is required for direct $PM_{2.5}$ emission based on dispersion modeling, AND the applicant must account for impact of precursor emissions from the project source.

- Case 4: If $PM_{2.5}$ emissions < 10 tpy and NOx &/or SO_2 emissions > 40 tpy, then $PM_{2.5}$ compliance demonstration not required for direct $PM_{2.5}$ emissions, BUT the applicant must account for impact of precursor emissions from the project source.

Since this project falls into Case 2 ($PM_{2.5}$ =48.8tpy, NOx=32.3tpy and SO2=8.7 tpy), only direct emissions of $PM_{2.5}$ were modeled, and no analysis of precursor emissions is necessary.

In January 2013, EPA vacated the PSD rules for using the SIL for $PM_{2.5}$. As a result, EPA has allowed a modified SIL comparison to be acceptable for $PM_{2.5}$. One can justify the use of the SIL if the difference between the NAAQS and the measured background in the area is greater than the applicable SIL value (refer to discussion in Section A-3.5-1).

Since the project is PSD for particulate matter, additional air quality analyses are necessary. PSD Increment modeling is required for particulate matter (PM_{10} and $PM_{2.5}$). The determined worst-case operating condition for the new turbines is used in the AERMOD increment modeling for Operational Scenario 2 (final build configuration for the new turbines). The PM increment-consuming sources (.i.e., new turbines, 2 MW cold start emergency engine, increase in gas-fired operating hours for Boilers 7 and 9 to allow year-round operation, and new cooling towers) are modeled at their maximum allowable emissions rates, while the increment expanding sources at MIT (i.e., retiring existing turbine, switch from No. 6 oil to primarily natural gas on Boilers 3,4, & 5 and switch from No. 2 oil to primarily natural gas on Boilers 7&9, retiring cooling towers) are modeled at their maximum actual emission rates (using a negative emission rate in AERMOD).

A visibility analysis was conducted using the U.S. EPA VISCREEN model for the Lye Brook Wilderness Area in southern Vermont. PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil.

A- 4.2 Air Quality Model Selection and Options

The U.S. EPA approved air quality model used for this analysis is AERMOD (v15181). Modeling was performed to identify maximum impact conditions and comparison of receptor concentrations to applicable levels and thresholds. The modeling of the maximum impact condition for each pollutant and averaging period was based on expected operating parameters and emission rates for both fuel options presented in Tables A-5 through A-11.

The AERMOD model is a steady state plume model using Gaussian distributions that calculates concentrations at each receptor for every hour in the year. The model is designed for rural or urban applications and can be used with a rectangular or polar system of receptors that are allowed to vary with terrain. AERMOD is designed to operate with two preprocessor codes: AERMET processes meteorological data for input to AERMOD, and AERMAP processes terrain elevation data and generates receptor information for input to AERMOD. The AERMOD model was selected for the air quality modeling analysis because of several model features that properly simulate the proposed facility environs, including the following:

- Concentration averaging time ranging from one hour to one year;
- Ability to model multiple sources; and
- Estimating cavity impacts; and
- Use of actual representative hourly average meteorological data; and
- Ability to calculate simple, complex, and intermediate terrain concentrations.

The AERMOD model has incorporated the latest EPA building downwash algorithm, the Plume Rise Model Enhancements (PRIME), for the improved treatment of building downwash. PRIME can also account for the stack placement relative to the building thereby allowing for the ability to estimate impacts in the cavity region near the stack.

The AERMODView graphical user interface (GUI) provided by Lakes Environmental, Inc. (Lakes) was used to set up the model inputs for this project. Additionally, Lakes provides a multi-processor version of the AERMOD executable which allows for significantly faster processing while producing identical output to the standard EPA version. For this project, the multi-processor version of the most recent version of AERMOD was used.

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

Modeling for MIT was performed with all regulatory options in AERMOD set.

A-4.2 Meteorological Data for Modeling

The meteorological data required to run AERMOD includes five years of representative surface and upper air observations. Hourly surface data from the National Weather Service (NWS) station at Boston Logan Airport with twice-daily upper air soundings from Gray, ME were used. These stations are the closest to and most representative of the Cambridge area. Logan Airport is approximately 4 miles to the east of MIT. The meteorological data for the period 2010-2014 were processed using the latest release of AERMET (15181), AERMINUTE and AERSURFACE programs. The profile base elevation for this station is 6 meters.

The methodology used in the meteorological data processing with AERMET (15181) is based on U.S. EPA guidance, as set out in the March 2013 EPA memo "Use of ASOS Meteorological Data in AERMOD Dispersion Modeling", 40 CFR Part 51 Appendix W, the AERSURFACE user's guide, and other U.S. EPA publications, and is described below:

- Land use data is determined using the latest version (13016) of the AERSURFACE utility.

- For AERSURFACE, 12 directional sectors and seasonal variation in land use parameters are used. A 1 km radius around the measurement site is used to determine surface roughness lengths.

- Per the AERSURFACE User's Guide, surface moisture characterization is determined by comparing annual precipitation totals to the 30-year climatological norm for the area: a year is classified as "dry" if annual precipitation was less than the 30th percentile value in the 30-year distribution, "wet" if greater than the 70th percentile, and "average" if between the 30th and 70th percentiles. Based on the Boston precipitation data 2010 and 2011 were classified as "wet", 2012 and 2013 were classified as "dry", and 2014 was classified as "average".

- AERMINUTE (version 14337) is used to incorporate 1-minute wind observations. A 0.5 m/s wind speed threshold is used for both AERMINUTE wind data.

- The MODIFY keyword, which performs automated QA/QC and data improvement algorithms on raw upper air data and is an established component of AERMET, is used.

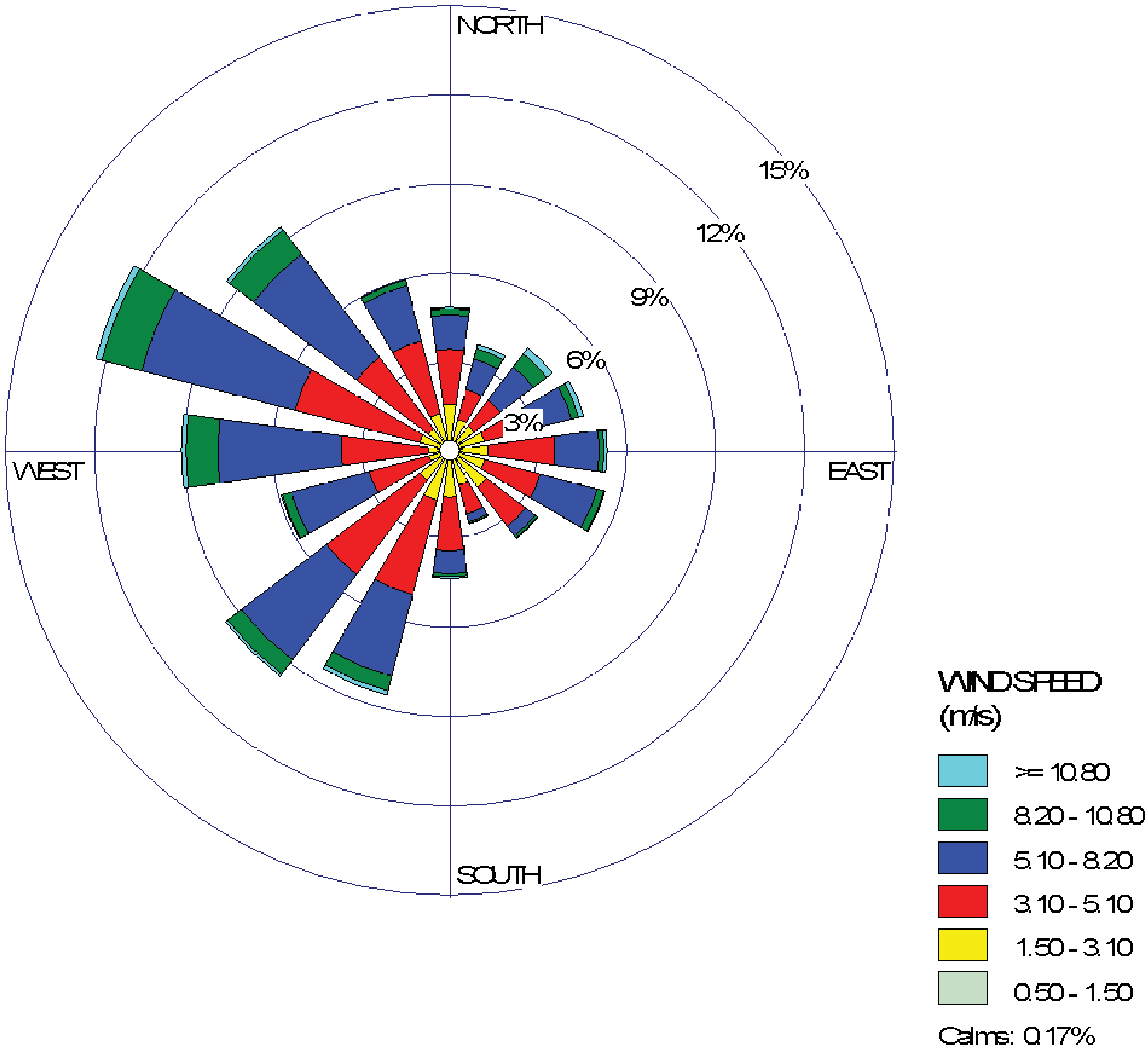
- In order to make a determination as to whether Boston experiences continuous snow cover during the winter months, the 30-year climatological (1981-2010) monthly normal snow depth data was used. During this period Boston experienced at least an inch of snow on the ground less than 50% of the time. Therefore, the continuous snow cover option was not utilized in AERSURFACE as the site does not experience continuous snow cover during the winter months.

- AERMOD-ready meteorological data is assessed for completeness using the U.S. EPA's PSD meteorological data standard – data must be 90% complete on a quarterly basis, with four consecutive quarters meeting that standard being necessary for one year of meteorological data to be considered valid.

A composite wind rose for the five years of meteorological data to be used in the modeling analysis is presented in Figure A-7. The winds are predominantly from the western sector (SSW through NW).

A-4.3 Receptor Grid

The same nested Cartesian grid of receptors that was used in previous modeling (MIT Boiler 9, 2011) was used in this study. The grid was generated with spacing of 20 meters in a 40 meter by 40 meter bounding box centered on the main CUP stack, 50 meter spacing out to 200 meters, 100 meter spacing out to 2 km, 500 meter spacing out to 5 km, and 1000 meter spacing out to 10 km. The nested grid of receptors was converted to discrete receptors and those falling on MIT buildings were removed from the analysis, allowing for ground level concentrations to be predicted.

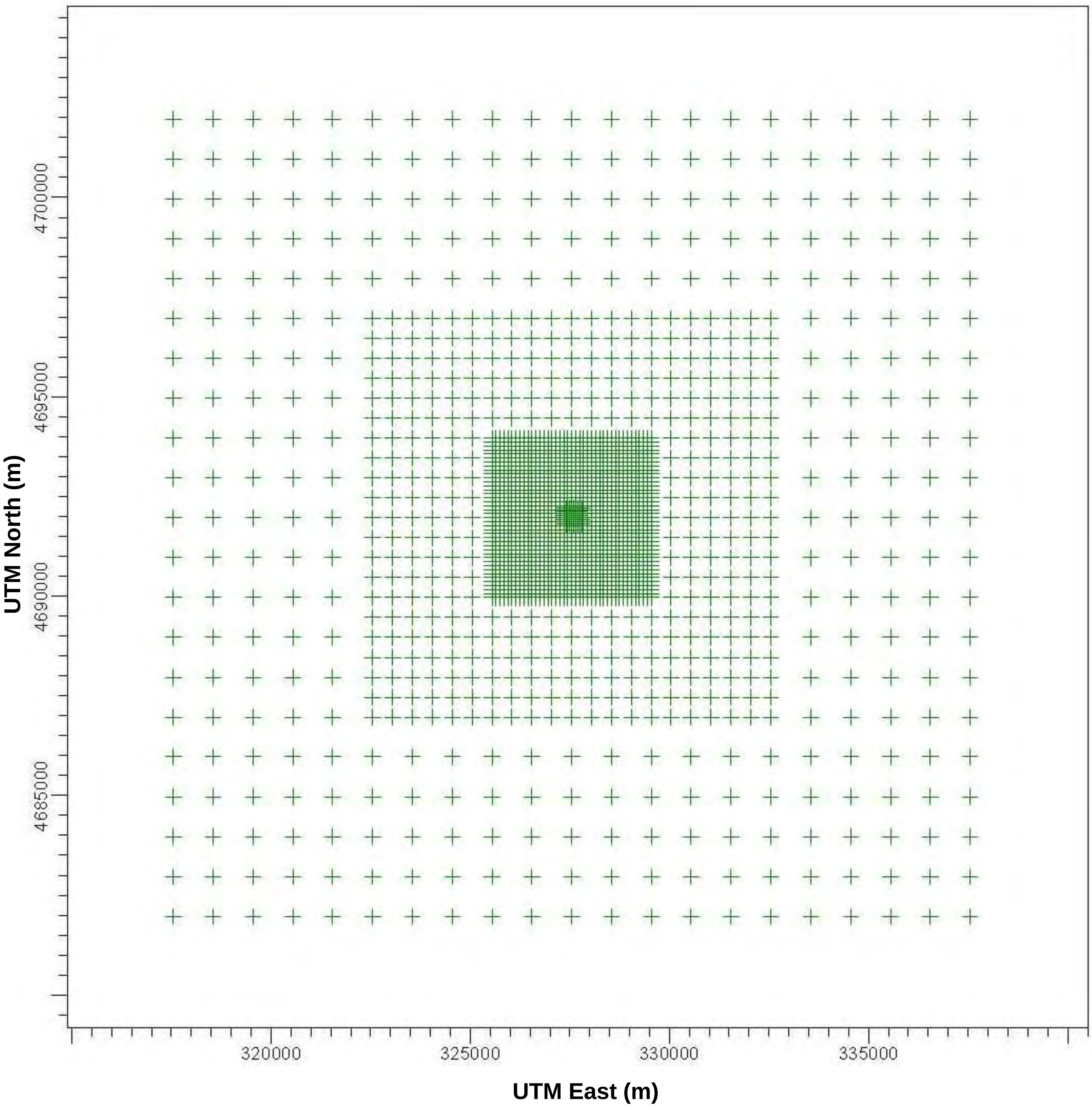


WIND DIRECTION
(blowing from)

Figure A-7

5-year (2009-2013) Wind Rose of Measurements from the Boston Logan International Airport NWS Station

Terrain around the immediate site is relatively flat. The terrain elevation for each receptor was obtained electronically from USGS digital terrain data. The National Elevation Dataset (NED), with a resolution of 1/3 arc-second (approximately 10 meters) was processed using the AERMAP (11103) program. Figure A-8 shows the nested receptor grid. A total of 2,415 receptors were modeled in AERMOD. Elevations and hill heights for each receptor as well as the base elevations of the sources modeled and buildings entered in BPIP-Prime were determined through the AERMAP processing.



MIT Receptor Spacing:
50 m out to 200 m
100 m out to 2 km
500 m out to 5 km
1000 m out to 10 km

Nested Receptor Grid used in AERMOD Modeling

A-5. AIR QUALITY IMPACT RESULTS

A-5.1 Turbine Load Analysis

A range of potential operating loads (25%, 50%, 75%, and 100%) were modeled for the new turbine units using two ambient temperatures (0 and 60 F) with the duct burners on. The turbines may burn natural gas with a backup fuel of ULSD. The duct burners will only operate on natural gas. Twenty options over a range of loads and ambient temperatures as shown in Attachment A were modeled to determine the case resulting in the highest air quality impact of each pollutant for each averaging period for each of the two Operational scenarios

The results of the load analysis are relied on for the remainder of the modeling. The cases resulting in the highest air quality impacts are listed in the Section A-3.3, the source data section, in Tables A-6 and A-7.

A-5.2 Significant Impact Level Analysis

The predicted air quality levels of the criteria pollutants were assessed through the initial modeling analysis of the CoGen Project sources, including the new turbines, 2MW cold start emergency engine and the cooling towers. Each of the Operating Scenarios was modeled for comparison with the SILs. Table A-15 presents the predicted concentrations compared to the SILs for each operating scenario. Maximum concentrations of 24-hour $PM_{2.5}$ and PM_{10} and annual $PM_{2.5}$ are above SILs (shown in bold) for all Operating Scenarios. Therefore, cumulative impact modeling was required to be performed for these operational scenarios for the pollutants/averaging period combinations with impacts above the SILs.

Table A-15. Proposed Project AERMOD Modeled Results for Operational Scenarios 1&2 Compared to Significant Impact Levels (SILs)

Poll.	Avg. Time	Form	Max. Modeled Conc. ($\mu g/m^3$)	SIL ($\mu g/m^3$)	% of SIL	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 1 (1 new turbine/HRSG)							
PM_{10}	24-hr	H	14.3	5	287%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
$PM_{2.5}$	24-hr (1)	H	11.3	1.2	945%	2010-2014	327550.08, 4692062.84, 2.73
	Ann. (1)	H	1.02	0.3	341%	2010-2014	327550.08, 4692062.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)							
PM_{10}	24-hr	H	17.1	5	342%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
$PM_{2.5}$	24-hr (1)	H	12.41	1.2	1034%	2010-2014	327550.08, 4692062.84, 2.73
	Ann. (1)	H	1.15	0.3	383%	2010-2014	327850.08, 4692362.84, 2.75

2 Concentrations averaged over 5 years.

A-5.3 National Ambient Air Quality Analysis

Since the proposed project is a modification to an existing facility, a compliance demonstration was conducted to ensure that the combined emissions from the existing facility and the proposed modification will not cause or contribute to a NAAQS violation for that pollutant (MassDEP, 2011). For the pollutants and averaging periods which had Project impacts below the SILs (Table A-15) the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. These results are presented in Section A-5.3.1. For those pollutants and averaging periods with Project impacts above the SILs, cumulative source modeling was conducted and is described in Section A-5.3.1.

Post-processing of 24-hour $PM_{2.5}$

As AERMOD is run for the 24-hour $PM_{2.5}$ impacts, the daily values of $PM_{2.5}$ monitored background were input directly to the model (as hourly values). The appropriate background value was added to the modeled impact depending on the day. Then the 98th percentile daily total impact (modeled + background) at each receptor for the multiyear average (5 years) was determined and the results compared to the 24-hour $PM_{2.5}$ standard.

A-5.3.1 Cumulative Impact Modeling

The results of the SILs analysis are used as the basis for the cumulative impact modeling. The Project's impacts are above the 24-hr and annual $PM_{2.5}$, and 24-hr PM_{10} SILs at some receptor locations. Cumulative impact modeling is required at these receptors to verify that the Project is not contributing significantly to a violation of the NAAQS.

Non-MIT facilities required for inclusion in the cumulative modeling are those emission sources within 10 km of the MIT CUP that emit significant $PM_{2.5}$, or PM_{10} (>10 tpy $PM_{2.5}$, or >15 tpy PM_{10} based on reported actual emissions). Four nearby facilities have been identified satisfying the criteria for PM_{10} and $PM_{2.5}$. The following facilities were identified as interactive sources for modeling purposes:

1. Veolia Kendall Station (~1.2 km to the east-northeast of MIT CUP)
2. Harvard Blackstone (~1.8 km to the west-northwest of MIT CUP)
3. MATEP (~3.0 km to the southwest of MIT CUP)
4. Boston Generating Mystic Station (~3.8 km to the north-northeast of MIT CUP)

Epsilon has worked with MassDEP to define the source parameters and emissions rates for the sources at the facilities proposed for the cumulative impact modeling. Title V operating permits for the facilities were reviewed. The emission rates used in the cumulative modeling represents the maximum permitted emission rates for each facility. The cumulative source parameters proposed in the modeling protocol have been revised prior to the modeling commencing. The parameters have been updated to better align the stack coordinates with the MIT modeling domain and to better reflect the operations at these facilities. In particular, the following changes were incorporated:

- A review of the most recent operating permit for Kendall Station resulted in the following updates:
- 1. Revised the exit velocity for Kendall Station Babcock Wilson #1-2, based on Unit #1 being taken out of service.
- 2. Revised the stack diameter for the Combined Cycle Turbine
- 3. Emission rates were adjusted because Kendall Station no longer burns No. 6 fuel oil.
- Georeferenced MrSID basemaps were imported into AERMODview based on the NAD83 Datum, and the interactive source coordinates presented in the protocol were evaluated for accuracy. All stack and building UTM coordinates were adjusted to accurately reflect their locations with respect to the MIT modeling domain datum.

The table of source parameters and emission rates used in the cumulative modeling for the interactive sources is presented in Attachment B.

The latest version of the EPA Building Profile Input Program (BPIP-Prime) was run for all stacks and buildings in the vicinity of each facility to create the building parameter inputs to AERMOD. The cumulative AERMOD modeling accounts for potential downwash for each stack at each facility.

Cumulative AERMOD modeling was conducted for each of the MIT CoGen Project Operating Scenarios with predicted impacts above the SILs. The cumulative modeling included the Project sources, existing MIT sources and the interactive sources listed in Attachment B. The cumulative impacts of all modeled sources plus the monitored background concentration are then compared to the NAAQS. The results of the cumulative source air quality modeling are presented in Table A-16.

The cumulative AERMOD modeling demonstrates that the MIT CoGen Project sources in any of the Operating Scenarios will not cause or contribute to a violation of the NAAQS.

Table A-16. AERMOD Model Results for the Full MIT Facility with Interactive Sources for Operational Scenarios 1 & 2 Compared to the NAAQS

Poll.	Avg. Period	Form	Total Conc. ($\mu g/m^3$)	AERMOD Predicted Contribution (μg/m3)					Bkgrnd Conc. ($\mu g/m^3$)	NAAQS (μg/m3)	% of NAAQS	Period	Receptor Location (m)
				MIT	Kendall Station	Harvard Blackstone	MATEP	Mystic Station					(UTME, UTMN, Elev.)
Operational Scenario 1 (1 new turbine/HRSG)													
PM_{10}	24-hr	H6H	85.7	0.045	32.4	0.23	0.0020	0.018	53.0	150	57.1%	12/28/10 hr 24	328750.08, 4692262.84, 2.16
$PM_{2.5}$	24-hr	H8H	29.9	16.31	0.31	0.014	0.26	0.20	12.8	35	85.6%	2010-2014	327550.08, 4692162.84, 2.73
	Annual	H	10.9	2.25	0.17	0.50	0.053	0.21	7.7	12	90.8%	2010-2014	327550.08, 4692112.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)													
PM_{10}	24-hr	H6H	85.7	0.037	32.4	0.23	0.0020	0.018	53.0	150	57.1%	12/28/10 hr 24	328750.08, 4692262.84, 2.16
$PM_{2.5}$	24-hr	H8H	28.2	12.44	0.22	0.18	0.29	0.099	15.0	35	57.1%	2010-2014	327550.08, 4692162.84, 2.73
	Annual	H	10.5	1.90	0.17	0.50	0.053	0.21	7.7	12	87.8%	2010-2014	327550.08, 4692112.84, 2.73

A-5.4 PSD Increment Modeling

A PSD increment is the maximum allowable increase in concentration that is allowed to occur above a baseline concentration for a pollutant. The baseline concentration is defined for each pollutant (and relevant averaging period) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. Modeling to show that allowable increments are not exceeded must include existing sources that are both within the baseline area and were constructed after the PSD baseline date and can include increment expanding sources (those that have added controls or stopped operating) after the PSD baseline date. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

The MIT CoGen Project is a major modification of an existing major source, subject to the requirement to obtain a PSD permit. PSD Increment modeling is required for fine particulate (PM_{10} and $PM_{2.5}$). Epsilon has conferred with MassDEP Boston BWP Air Planning and Evaluation Branch to determine if the $PM_{2.5}$ minor source baseline date has been established for the baseline area (county). It is believed that this application will establish the baseline date for $PM_{2.5}$ when it is determined to be complete. MassDEP confirmed that the baseline has been set for PM_{10} in Middlesex County. Increment-consuming sources (.i.e., new turbines, 2 MW cold start emergency engine and new cooling towers) will be modeled at their maximum allowable emissions rates, while the increment expanding sources at MIT (i.e., retiring existing turbine, switch from No.6 oil to No. 2 oil on Boilers 3, 4 & 5, 7 & 9, and retiring cooling towers) will be modeled at their maximum actual emission rates (using a negative emission rate in AERMOD). The previously determined worst-case operating condition for the new turbines was used in the AERMOD increment modeling. Since the baseline has not been previously established for $PM_{2.5}$, there will be no other $PM_{2.5}$ increment-consuming sources in the baseline area to include in the PSD Increment Modeling. However, for PM_{10} the baseline has been established and the following sources will be included as increment consuming: GenOn Kendall Station, Harvard Blackstone, MATEP, and Mystic Generating Station.

The actual emissions are determined for the existing sources at MIT in accordance with the October 1990 draft guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, which states the following:

> *For any increment-consuming (or increment-expanding) emissions unit, the actual emissions limit, operating level, and operating factor may all be determined from source records and other information (e.g., State emissions files), when available, reflecting actual source operation. For the annual averaging period, the change in the actual emissions rate should be calculated as the difference between:*

- the current average actual emissions rate, and
- the average actual emissions rate as of the minor source baseline date (or major source baseline date for major stationary sources).

In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).

For each short-term averaging period (24 hours and less), the change in the actual emissions rate for the particular averaging period is calculated as the difference between:

- the current maximum actual emissions rate, and
- the maximum actual emissions rate as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing construction before the minor source baseline date).

In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.

Following this guidance the MIT source operation records were reviewed for the 2-year period of April 1, 2013 – March 31st, 2015 for Boilers 3, 4, 5, 7 & 9, and the existing combustion turbine and duct burner. The maximum gas and oil usage were determined for a 24-hour period and the actual emission rate calculated based on the Lb/MMBTU permit limits in the current Title V operating permit for MIT. Emission statement data was reviewed for cooling towers 1, 2, 3, 4, 5, 6.

The current actual emission rates (annual emissions after the change) for MIT are as follows:

- For the new CT units, the proposed permit limits for natural gas firing times 8,592 hours/year, plus the proposed permit limits for ULSD firing for 168 hours/yr.
- For the new CT unit duct burners, the proposed permit limits times 8.760 hours/year (natural gas only)
- For the new cold start emergency engine, the proposed permit limit times an annual operating restriction of 300 hours/year (ULSD)
- For Boilers 7 & 9, the proposed permit limits for natural gas firing times 8,592 hours/year plus the proposed permit limits for ULSD firing for 168 hours/year. This reflects the requested increase in allowable operating hours.
- For Boilers 3, 4, & 5, the average of the actual total heat input (gas & oil) for the 2-year period of April 1st, 2013 – March 31st, 2015 times the natural gas per pound MMBtu permit limits in the current operating permit for MIT. Added to this are the permit limits for ULSD firing for 168 hours/year.

- For the new cooling towers, the proposed potential emission rate.

The PSD Increment modeling emission rates for MIT are summarized in Table A-17. Calculations are provided in Attachment C.

Table A-17. PM Emission Rates used in PSD Increment Modeling for MIT

Increment Consuming Sources		
	$PM_{10}/PM_{2.5}$ Emission Rate short term (g/s)	$PM_{10}/PM_{2.5}$ Emission Rate annual (g/s)
Boiler 3	0.071 (NG)	0.037 (NG/ULSD)
Boiler 4	0.069(NG)	0.040 (NG/ULSD)
Boiler 5	0.076 (NG)	0.048 (NG/ULSD
Total	0.215	0.126
Boiler 7	0.063 (NG)	-
Boiler 9	0.083 (NG)	0.164 (NG/ULSD)
Total	0.146	0.164
Cooling Towers #11, 12, 13 per cell (6)	0.0044	0.0044
Total	0.026	0.026
Cold Start Engine	0.0168	0.014
Increment Expanding Sources		
Existing Turbine	1.27	0.21
Duct Burner	0.032	0.018
Total	1.31	0.24
Boiler 3 (No. 6)	0.54	0.088
Boiler 4 (No. 6)	0.82	0.100
Boiler 5 (No. 6)	0.71	0.126
Total	2.066	0.315
Boiler 7	0.20	-
Boiler 9	0.23	0.028
Total	0.42	0.028
Cooling Tower 1 per cell (2)	3.33E-3	3.33E-3
Cooling Tower 2 per cell (2)	3.33E-3	3.33E-3
Cooling Tower 3 per cell (2)	5.86E-3	5.86E-3
Cooling Tower 4 per cell (2)	5.18E-3	5.18E-3
Cooling Tower 5	2.15E-3	2.15E-3
Cooling Tower 6	2.15E-3	2.15E-3
Total	0.034	0.034

As mentioned previously, the PM-10 baseline has been previously triggered and it becomes necessary to perform modeling of the proposed changes for MIT in conjunction with changes in the PM-10 baseline area as increment consuming. Emissions were modeled at the potential to emit rates as a conservative measure even though MIT had the option of modeling these sources at their actual emission rates. The following sources were included for the PM-10 PSD increment modeling only and are summarized in Attachment B:

- Kendall Station: Babcock & Wilson #1-2, Babcock & Wilson #3, Turbopower CTG#1, and the Combined Cycle Turbine
- Harvard Blackstone: The new combined heat and power system, and Boiler 13
- MATEP: Stack (Two identical flues)
- Mystic Station: CTG/HRSG #81, CTG/HRSG #82, CTG/HRSG #93, and CTG/HRSG #94

The PM-10 Emission Rates for the interactive sources used in the PSD Increment Modeling are summarized in Table A-18.

Table A-18. PM-10 Emission Rates used in PSD Increment Modeling for Interactive Sources

PM10 PSD Increment Consuming Sources	
Kendall Station	PM_{10} Emission Rate g/s
Babcock & Wilson #1-2	0.81
Babcock & Wilson #3	1.22
Turbopower CTG #1	0.47
Combined Cycle Turbine	6.3
Harvard Blackstone	
Boiler 6 & Boiler 13	3.53
New CHP	0.47
MATEP	
Stack (Two identical flues)	4.29
Mystic Station	
CTG/HRSG #81	4.1
CTG/HRSG #82	4.1
CTG/HRSG #93	4.1
CTG/HRSG #94	4.1

All sources are input in the AERMOD model with increment consuming sources using positive emissions rates and increment expanding sources with negative emission rates.

The PSD increment comparison was run for Operational Scenario 2 only as this is the final build scenario for this project. All impacts are matched in space and time and the resultant impact is compared to the PSD increment. The maximum resultant impact is used for annual averages and the highest second-high resultant impact is used for the 24-hr averages. The results of the PSD increment analysis are presented in Table A-19. The analysis shows that applicable PSD increments are not exceeded at any receptor for any MIT CoGen operating scenario.

Table A-19. AERMOD Model Results for Operational Scenarios 2 compared to PSD Increments

Poll.	Avg. Period	Form	Resultant Modeled Conc. (μg/m^3)	Increment (μg/m3)	% of Increment	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 2							
PM_{10}	24-hr	H2H	10.5	30	35.0%	5/9/10 hr: 24	327650.08, 4692062.84, 2.74
$PM_{2.5}$	24-hr	H2H	8.9	9	98.9%	5/9/10 hr: 24	327650.08, 4692062.84, 2.74
	Annual	H	1.3	4	32.5%	2011	327850.08, 4692362.84, 2.75

A-5.5 Class I Visibility Analysis

Section 169A of the Clean Air Act states "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man made air pollution." Under the regulations promulgated for visibility protection (40 CFR 51.301 (x)) visibility impairment is defined as "…any humanly perceptible change in visibility (visual range, contrast, coloration) from that which would have existed under natural conditions." As part of this air quality analysis, a visibility impact analysis was performed.

The Lye Brook Wilderness Area in southern Vermont is the closest Class I area to the MIT CUP. Lye Brook is located approximately 175.5 km to the northwest of MIT. As part of the Regional Haze Regulations, EPA has devised a screening criterion for sources located more than 50 km from the Class I area. A source is considered to have negligible impacts when the combined annual emissions of SO_2, NOx, PM_{10}, and H_2SO_4 (in tons) divided by the distance (in km) from the Class I area is 10 or less. In this case, this ratio is about 0.46 (79.9 tons/175.5 km). Therefore, the proposed modifications to the source are expected to have negligible visibility impacts with respect to the Lye Brook Wilderness Area, and would not require any further Class I visibility impact analyses.

To confirm this result, a visibility analysis of the proposed project was conducted using the EPA VISCREEN program (Version 1.01 dated 88341). The VISCREEN model (EPA, 1992) provides the capability of assessing plume contrast (Cp) and plume perceptibility (Delta E) against two backgrounds: sky and terrain.

Visibility impacts are a function of particulate and NO_2 emissions. Particles are capable of either scattering or absorbing light while NO_2 absorbs light. It should be noted that NO_2 absorbs light greater in the blue end of the spectrum. These constituents can either increase or decrease the light intensity (or contrast) of the plume against its background. VISCREEN plume contrast calculations are performed at three wavelengths within the visible spectrum (blue, green, and red). Plume perceptibility as determined by VISCREEN is determined from plume contrast at all visible wavelengths and "is a function of changes in both brightness and color" (EPA, 1992).

The VISCREEN model provides three levels of analysis; Level 1, Level 2, and Level 3. The first two Levels are screening approaches. If the Project fails a Level-1 screening analysis, then more refined modeling must be conducted.

The perceptibility of a distinct plume depends on the plume contrast at all visible wavelengths. Perceptibility is a function of changes in both brightness and color. The color difference parameter, ΔE, was developed to specify the perceived magnitude of changes in color and brightness and is used as the primary basis for assessing perceptibility of plume visual impacts in the screening analysis. Plume contrast results from an increase or decrease in light transmitted from the viewing background through the plume to the observer. This increase or decrease in light intensity is caused by plume constituents that scatter and/or absorb light. The first criterion is a ΔE value of 2.0; the second is a contrast value of 0.05 (EPA 1992).

A Level 1 VISCREEN analysis was performed on the nearest Class I area; Lye Brook Wilderness Area. Level 1 Screening in the VISCREEN model is designed to provide a conservative estimate of visual impacts from the plume. This conservatism is achieved by assuming worst-case meteorological conditions: extremely stable (F) atmospheric conditions, coupled with a very low wind speed (1 meter per second [m/s]) persisting for 12 hours, with a wind that would transport the plume directly adjacent to the observer. The observer is located at the closest location of the Class I area to the proposed source per VISCREEN guidance (EPA 1992), in this case, it is the east area of the Lye Brook Wilderness Area.

To be conservative, the proposed worst case new turbine emissions for each pollutant were used: PM/NO_x (2 turbines at 100% load, 0ºF, ULSD). In addition to the turbines emissions, the total emission rate includes the 2 MW cold start emergency engine (for PM and NO_x) and the cooling towers (for PM only). The total PM emission rate (25.8 lb/hr) and total NO_x emission rate (55.37 lb/hr) were input into the VISCREEN model. The minimum (175.5 km) and maximum (181.8 km) distances from the source to the Lye Brook Wilderness Area were input. A default background visual range of 194.8 km was used (U.S. Department of Interior, 2010). Table A-20 presents results of the VISCREEN modeling analysis completed for the MIT Cogen project.

The VISCREEN modeling demonstrates that the addition of the new turbines, 2 MW cold start emergency engine and the cooling towers associated with the MIT Cogen project will comply with the criteria established in the Workbook for Plume Visual Impact Screening and Analysis (Revised) (EPA 1992) for maximum visual impacts inside the Lye Brook Wilderness Area.

Table A-20 Class I Visibility Modeling Results -Maximum Visual Impacts Inside the Class I Area

					Delta-E		Absolute Contrast	
Background	Theta (°)	Azimuth (°)	Distance (km)	Alpha (°)	Screening Criteria	Plume	Screening Criteria	Plume
SKY	10	84	175.5	84	2.00	0.226	0.05	0.003
SKY	140	84	175.5	84	2.00	0.054	0.05	-0.002
TERRAIN	10	84	175.5	84	2.00	0.178	0.05	0.002
TERRAIN	140	84	175.5	84	2.00	0.022	0.05	0.001

A-5.6 Effects on Soils and Vegetation Analyses

PSD regulations require analysis of air quality impacts on sensitive vegetation types, with significant commercial or recreational value, or sensitive types of soil. Evaluation of impacts on sensitive vegetation is by comparison of predicted project impacts with screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, 1980). These procedures specify that predicted impact concentrations used for comparison account for project impacts and ambient background concentrations.

Most of the designated vegetation screening levels are equivalent to or exceed NAAQS and/or PSD increments, so that satisfaction of NAAQS and PSD increments assures compliance with sensitive vegetation screening levels. Since there are no specific PM_{10} or $PM_{2.5}$ screening level sensitive concentrations, no formal comparison was performed.

A-5.7 Growth

The peak construction work force is estimated to be 300 persons. MIT would not expect to add staff for plant operations.

It is expected that a significant construction force is available and is supported by the fact that within the Cambridge/Boston area, significant construction activities have already occurred. Therefore, it is expected that because this area can support the Project's construction from within the region, new housing, commercial and industrial construction will not be necessary to support the Project during the building period.

If any new personnel do move to the area to support the Project, a significant housing market is already established and available. Therefore, no new housing is expected. Due to the significant level of existing commercial activity in the area, new commercial construction is not foreseen to be necessary to support the Project's work force. In addition, no significant level of industrial related support will be necessary for the Project, thus industrial growth is not expected.

Thus, no new significant emissions from secondary growth during either the construction phase or operations are anticipated.

A-5.8 Environmental Justice

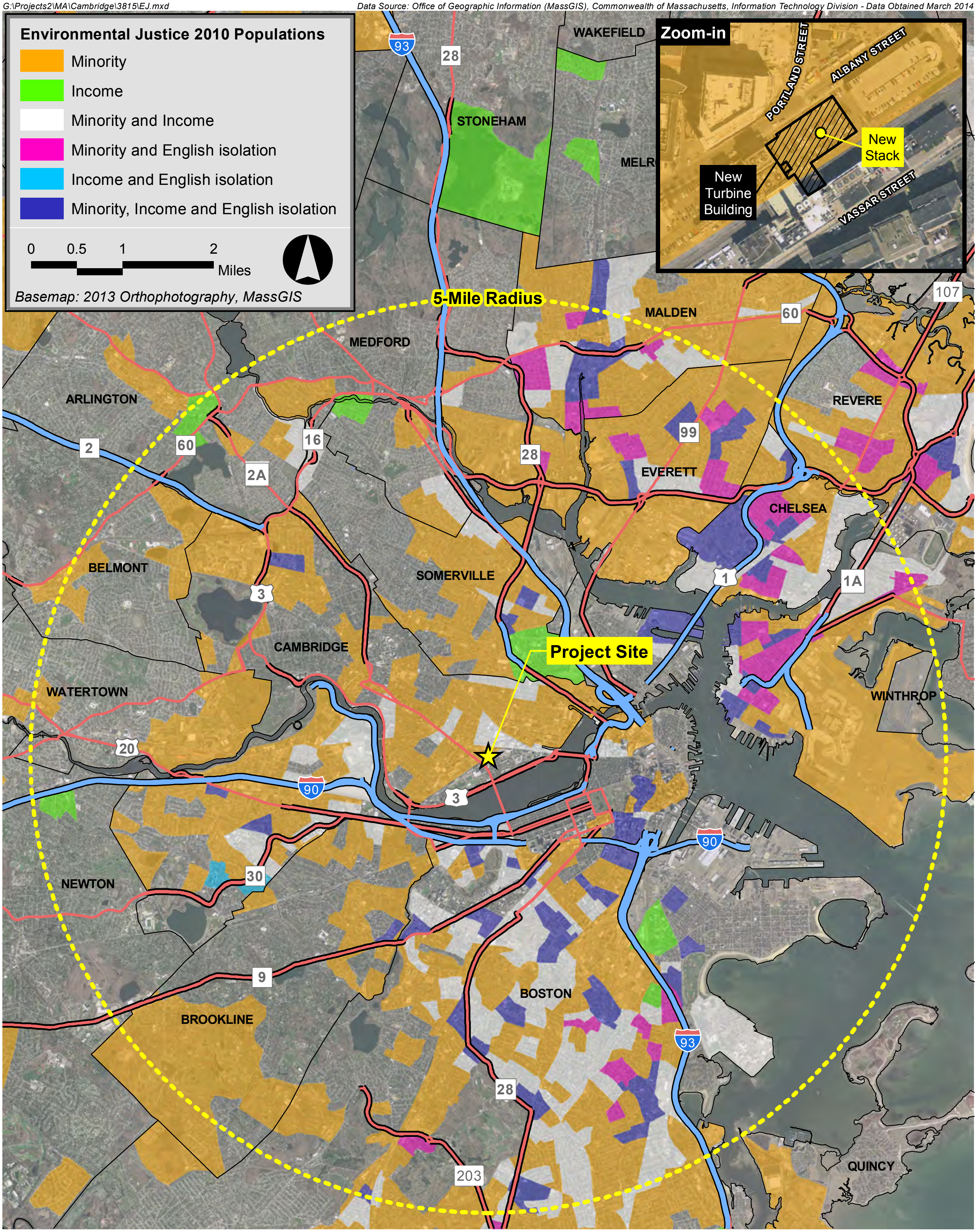
Section 4.2 of the PSD permit application includes documentation to enable MassDEP to fulfill its obligation under the provisions of the April 11, 2011 PSD Delegation Agreement between MassDEP and EPA to "identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of federal programs, policies, and activities on minority and low-income populations as set forth in Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Office of Energy and Environmental Affairs (EEA) has established environmental justice neighborhoods which identify areas with minority populations and low-income populations. Figure A-9 identifies the environmental justice neighborhoods in the vicinity of MIT.

In order to demonstrate that the project's impacts will not have a disproportionately high impact on minority and low-income populations, a population weighted average concentration for PM_{10} and $PM_{2.5}$ was computed using the worst case AERMOD impacts Operating Scenario from all of the MIT sources for each averaging period. The population weighted concentrations were calculated for areas classified as environmental justice areas and compared to population weighted concentrations in areas not classified as environmental justice areas within 5 miles of the Project. The results are presented in Table A-21. The results demonstrate that the impacts from the proposed project are not disproportionately high in the environmental justice areas when compared to areas not classified as Environmental Justice areas.

Table A-21 Population-weighted Predicted Impacts

		Population-weighted Concentration ($\mu g/m^3$)	
Pollutant	Averaging Period	Non-EJ Areas	EJ Areas
$PM_{2.5}$	24-hour	1.7	1.8
	Annual	0.04	0.05
PM_{10}	24-hour	1.3	1.4

As previously demonstrated in Table A-16, the project impacts for all pollutants and operational scenarios are below the NAAQS, which are considered protective of the health of sensitive populations such as asthmatics, children and the elderly. The total impacts presented in Table A-16 include modeled impacts from all of the MIT sources (existing plus new sources), plus modeled impacts from other significant emitters within 10 km of MIT, plus ambient monitored values. Therefore, it has been demonstrated that there is no adverse impact expected within in any Environmental Justice areas within 10 km of MIT.



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon Associates Inc.

Figure A-9

Environmental Justice 2010 Populations

A-6. REFERENCES

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ATTACHMENT A

Source Parameters for New Turbine Load Cases

Table A-1. MIT turbine & duct burner model cases per turbine

Case	I.a	I.b	I.c	I.d	I.e	I.f	I.g	I.h	I.i	I.j	2.a	2.b	2.c	2.d	2.e	2.f	2.g	2.h	2.i	2.j
Ambient Temp (F)	60	0	60	60	60	0	0	0	60	0	60	0	60	60	60	0	0	0	60	0
% Load	100	100	50	25	75	50	100	75	50	50	100	100	50	25	75	50	100	75	50	50
Turbine Fuel	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Turbine Fuel Input (mmBTU/hr, HHV)	255.7	255.7	147.9	99.8	197.8	148.9	247.7	193.5	142.9	143.9	255.7	255.7	147.9	99.8	197.8	148.9	247.7	193.5	142.9	143.9
Duct Burner Fuel Input (mmBTU/hr, HHV)	125.0	134.3	93.7	32.2	121.9	100.7	134.3	121.9	93.7	100.7	125.0	134.3	93.7	32.2	121.9	100.7	134.3	121.9	93.7	100.7
Stack Exit Temp. (F)	180	180	180	180	180	180	225	225	225	225	180	180	180	180	180	180	225	225	225	225
Stack Flow Rate (ft3/min)	151,371	157,717	99,803	87,312	134,264	111,944	170,077	142,888	120,274	127,457	302,741	315,433	199,606	174,624	268,529	223,887	340,153	285,777	240,549	254,913
# of Turbines Operating	1	1	1	1	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2
Emission Rates (Turbine Only) - Lb/Hr																				
PM10	5.11	5.11	2.96	2.00	3.96	2.98	9.91	7.74	5.71	5.76	10.23	10.23	5.92	3.99	7.91	5.96	19.81	15.48	11.43	11.51
PM2.5	5.11	5.11	2.96	2.00	3.96	2.98	9.91	7.74	5.71	5.76	10.23	10.23	5.92	3.99	7.91	5.96	19.81	15.48	11.43	11.51
Duct Burner - Lb/Hr																				
PM10	2.50	2.69	1.87	0.64	2.44	2.01	2.69	2.44	1.87	2.01	5.00	5.37	3.75	1.29	4.87	4.03	5.37	4.87	3.75	4.03
PM2.5	2.50	2.69	1.87	0.64	2.44	2.01	2.69	2.44	1.87	2.01	5.00	5.37	3.75	1.29	4.87	4.03	5.37	4.87	3.75	4.03
Total Emissions (Lb/Hour)																				
PM10	7.61	7.80	4.83	2.64	6.39	4.99	12.59	10.18	7.59	7.77	15.23	15.60	9.67	5.28	12.79	9.99	25.19	20.35	15.18	15.54
PM2.5	7.61	7.80	4.83	2.64	6.39	4.99	12.59	10.18	7.59	7.77	15.23	15.60	9.67	5.28	12.79	9.99	25.19	20.35	15.18	15.54
Total Emissions (g/s)																				
PM10	9.59E-1	9.83E-1	6.09E-1	3.33E-1	8.06E-1	6.29E-1	1.59E+0	1.28E+0	9.56E-1	9.79E-1	1.92E+0	1.97E+0	1.22E+0	6.65E-1	1.61E+0	1.26E+0	3.17E+0	2.56E+0	1.91E+0	1.96E+0
PM2.5	9.59E-1	9.83E-1	6.09E-1	3.33E-1	8.06E-1	6.29E-1	1.59E+0	1.28E+0	9.56E-1	9.79E-1	1.92E+0	1.97E+0	1.22E+0	6.65E-1	1.61E+0	1.26E+0	3.17E+0	2.56E+0	1.91E+0	1.96E+0
Stack Parameters																				
STACK TEMP., deg K	355.4	355.4	355.4	355.4	355.4	355.4	380.4	380.4	380.4	380.4	355.4	355.4	355.4	355.4	355.4	355.4	380.4	380.4	380.4	380.4
STACK EXIT VEL., m/sec	20.0	20.8	13.2	11.5	17.7	14.8	22.5	18.9	15.9	16.8	20.0	20.8	13.2	11.5	17.7	14.8	22.5	18.9	15.9	16.8

AERMOD v15181 x/Q results																				
24-hr High (X/Q)	9.64817	9.37967	12.52268	13.411	10.42475	11.51840	8.63415	9.81477	10.86444	10.52972	5.79028	5.17086	9.61588	10.43926	7.48855	8.8245	4.19419	6.42944	7.98951	7.61395
24-hr High (X/Q) (5yr avg)	7.90057	7.54556	11.22098	12.22987	8.79839	10.30070	6.68165	8.09645	9.3369	8.89938	4.22640	4.04701	7.89438	8.80836	5.37687	7.0098	3.67818	4.5677	6.01052	5.54094
Maximum Predicted Concentration (ug/m^3)																				
24-hr PM10/PM2.5	7.57991	7.41645	6.83392	4.06725	7.08867	6.48071	**10.60203**	10.38107	8.92861	8.71458	8.10973	7.95552	9.61584	5.85874	8.66405	8.82046	11.67262	**11.71319**	11.49537	10.85176

ATTACHMENT B

Source Parameters for Cumulative Impact Modeling

Table B-1. Source Parameters and Emission Rates for Cumulative Modeling Analysis

Facility/Sources	UTM* East	UTM* North	Stack Dimensions		Exit Velocity	Exit Temp	$PM_{2.5}$	PM_{10}
	(m)	(m)	Height (m)	Diam(m)	(m/s)	(ºK)	(g/s)	(g/s)
Kendall Station								
BABCOCK & WILSON #2	328780.78	4692241.85	53.3	3.05	6.25	427.6	0.81	0.81
BABCOCK & WILSON #3	328760.64	4692244.83	53.3	2.92	9.45	460.9	1.22	1.22
TURBOPOWER CTG#1	328659.10	4692298.20	9.9	4.08	39.62	838.7	0.47	0.47
COMBINED CYCLE TURBINE	328722.3	4692228.1	76.2	5.11	28.96	394.3	6.3	6.3
Harvard Blackstone								
Turbine – ULSD; No Duct Fire (CHP) -ST	325795.40	4692345.70	33.5	1.25	19.21	444.3	0.47	0.47
Turbine – ULSD; No Duct Fire (CHP) –AN	325795.40	4692345.70	33.5	1.25	19.07	432.6	0.38	0.38
STACK 2 (Boilers 11 and 12)	325832.90	4692316.60	48.8	3.04	12.50	435.9	8.65	8.65
STACK2 (Boilers 6 and 13)	325806.80	4692328.70	45.7	3.66	10.36	469.3	3.53	3.53
MATEP								
STACK (TWO IDENTICAL FLUES)	326436.20	4689289.80	96.0	4.23	11.31	433.3	4.29	4.29
*Boston Generating Mystic Station***								
HIGH PRESSURE BLR #7 (DUAL FUEL)	329748.60	4695288.90	152.4	3.66	25.91	443.9	34.7	34.7
CTG/HRSG #81	329943.60	4695254.20	93.0	6.25	22.04	365.0	4.1	4.1
CTG/HRSG #82	329944.80	4695263.20	93.0	6.25	22.04	365.0	4.1	4.1
CTG/HRSG #93	329957.30	4695325.40	93.0	6.25	22.04	365.0	4.1	4.1
CTG/HRSG #94	329958.90	4695333.60	93.0	6.25	22.04	365.0	4.1	4.1
ROLLS ROYCE CTG	329630.00	4695256.40	9.1	3.66	12.8	810.9	2.8	2.8

* UTM Coordinates are NAD83, Zone 19N

** Mystic Station Units 4, 5, and 6 were not included in source parameters provided by Steve Dennis, MassDEP October 25 and 30, 2012. Those sources can be excluded from the cumulative modeling.

ATTACHMENT C

Calculations of Actual Emission Rates for PSD Increment Modeling

Table C-1. PM Short-term Emission Calculations based on Actual Operations

	Oil Historical Usage					NG Historical Usage				
Source	Max Oil Usage in a 24-hour period (gallons)	24-hour Period	Total MMBTU on Oil	EF OIl (Lb/MMBTU)	Actual Emission Oil Rate (lb/hr)	Max Gas Usage in a 24-hour period (scf)	24-hour Period	Total MMBTU on Gas	EF Gas (Lb/MMBTU)	Actual Emission Gas Rate (lb/hr)
Boiler 3	13,214	12/31/2013	1876	0.055	4.30	1,754,043	12/8/2014	1754	0.0076	0.56
Boiler 4	19,948	2/6/2015	2833	0.055	6.5	1,742,543	12/25/2013	1743	0.0076	0.55
Boiler 5	17,284	2/6/2015	2454	0.055	5.6	1,894,732	12/8/2014	1895	0.0076	0.60
Existing CT	43,976	1/24/2014	6245	0.04	10.1	6,192,320	12/13/2013	6192	0.007	1.81
Existing DB	N/A	N/A	N/A	N/A	N/A	1,190,100	4/2/2013	1190	0.005	0.25
Boiler 7	9,163	2/24/2015	1301	0.030	1.6	1,202,035	2/16/2015	1202	0.010	0.50
Boiler 9	10,210	2/24/2015	1450	0.030	1.8	1,580,329	3/23/2015	1580	0.010	0.66

Period of Available Data for All Emission Units is: 4/1/13 - 3/31/15

Table C-2. PM Annual Emission Calculations based on Actual Operations

Annual PSD Increment Expanding Emission Calculation									
	Oil Historical Usage				NG Historical Usage				
Source	Average Oil Usage over 2 Year period (gallons)	Total MMBTU Oil	EF OIl (Lb/MMBTU)	Annual PM Oil Emissions Lb/Yr	Average Gas Usage Over a 2 Year period (scf)	Total MMBTU on Gas	EF Gas (Lb/MMBTU)	Actual PM Gas Emissions (lb/yr)	Expanding Emission Rate Total Lb/hr
Boiler 3	6.72E+05	9.54E+04	0.055	5,248	1.15E+08	1.15E+05	0.0076	872	0.7
Boiler 4	7.84E+05	1.11E+05	0.055	6,123	1.19E+08	1.19E+05	0.0076	907	0.8
Boiler 5	9.84E+05	1.40E+05	0.055	7,684	1.17E+08	1.17E+05	0.0076	891	1.0
Existing CT	6.92E+05	9.82E+04	0.04	3,930	1.59E+09	1.59E+06	0.007	11,141	1.7
Existing DB	N/A	N/A	N/A	N/A	2.43E+08	2.43E+05	0.005	1,214	0.14
Boiler 7	1.11E+04	1.57E+03	0.030	47	6.39E+06	6.39E+03	0.010	64	0.013
Boiler 9	2.93E+04	4.16E+03	0.030	125	1.21E+07	1.21E+04	0.010	121	0.028

Period of Available Data for All Emission Units is: 4/1/13 - 3/31/15

Table C-3. PM Annual Emission Consuming Calculations based on Actual Operations for Boilers 3, 4, & 5

Annual PSD Increment Consuming Emission Calculation										
Source	Total MMBTU/hr Oil	Total MMBTU/hr Gas	Total MMBTU/hr	NG Emission Limit (lb/MMBTU)	NG Emissions (lb/yr)	Hrs/Yr Oil	MMBTU/hr Oil	Oil Emission Limit (lb/MMBtu)	Oil Emissions (lb/yr)	Consuming Emission Rate Total Lb/hr
Boiler 3	9.54E+04	1.15E+05	2.10E+05	0.0076	1,597.5	168	116.2	0.055	1,073.7	0.30
Boiler 4	1.11E+05	1.19E+05	2.31E+05	0.0076	1,753.0	168	116.2	0.055	1,073.7	0.32
Boiler 5	1.40E+05	1.17E+05	2.57E+05	0.0076	1,952.6	168	145.2	0.055	1,341.6	0.38

Period of Available Data for All Emission Units is: 4/1/13 - 3/31/15

Table C-4. PM Annual Emission Consuming Calculations for Boilers 7 & 9

Annual PSD Increment Consuming Emission Calculation									
Source	NG Hrs/Yr	MMBTU/hr Gas	NG Limit (Lb/MMBTU)	NG Emissions (Lb/yr)	Oil Hrs/yr	MMBTU/hr Oil	Oil Limit (Lb/MMBTU)	Oil Emissions (lb/yr)	Consuming Emission Rate Total Lb/hr
Boiler 7	8592	99.7	0.01	8,566.2	168	99.7	0.03	502.5	1.0
Boiler 9	8592	125.8	0.01	10,808.7	168	119.2	0.03	600.8	1.3

Period of Available Data for All Emission Units is: 4/1/13 - 3/31/15

APPENDIX B

Supplemental Information

GE Power & Water
Distributed Power

LM2500 Base/LM2000 Gas Turbine (50 Hz)

fact sheet

Technology

Derived from the CF6 family of aircraft engines used on wide-body jetliners, the LM2500 Base and the LM2000 are hot-end drive, two-shaft gas generators with a free power turbine. Thermal efficiencies are from 34% to 36%.

- Baseload power capabilities of 17–23 MW ISO
- Unsurpassed reliability – exceeding 99%
- Two models with a high degree of parts commonality

Experience

Maintaining a high degree of commonality with its flight-tested forerunners, the LM2500 family continues to build its reputation as the most reliable industrial gas turbine generator in its class.

- 57 million operating hours
- More than 2,000 units
- End-users – mechanical drive and power generation for industrial plants, pipelines, platforms, and marine
- Configurations – simple cycle, cogeneration, and combined cycle

Innovation

GE offers two models in the LM2500 Base family of products:

LM2500 Base

- Produces in excess of 23 MW ISO
- Operates at 3,000 or 3,600 rpm without a gearbox
- Optional steam injection (STIG) for power enhancement

LM2000

- Capable of over 17 MW ISO
- Extended maintenance intervals
- Large degree of commonality with LM2500 Base

Performance

Model	Output	Heat Rate		Pressure Ratio	Power Turbine Speed	Exhaust Flow		Exhaust Temp.	
	MWe	Btu/kWh	kJ/kWh		RPM	lb/sec	kg/sec	°F	°C
50 HZ									
LM2000PS	17.7	9,772	10,310	16.0	3,000	141.9	64.3	894	479
LM2000PS*	18.4	10,094	10,648	16.1	3,000	145.9	66.3	866	463
LM2000PN DLE	17.9	9,888	10,430	15.4	3,000	140.2	63.7	925	496
LM2500PE	22.4	9,618	10,146	18.2	3,000	153.6	69.8	1001	538
LM2500PE*	23.1	10,027	10,577	18.7	3,000	157.8	71.7	963	517
LM2500PJ DLE	21.8	9,644	10,173	17.9	3,000	151.6	68.9	995	535

* with water injection for NO_X control to 25 ppm

Notes: Performance based on 15°C amb temp, 60% RH, sea level, no inlet/exhaust losses on natural gas fuel with no NO_X media, unless otherwise specified. Average engine. Turbine inlet temp, exhaust flow and exhaust temp at ISO rating conditions. Generator output at 11.5kV, 0.90 PF.

Service

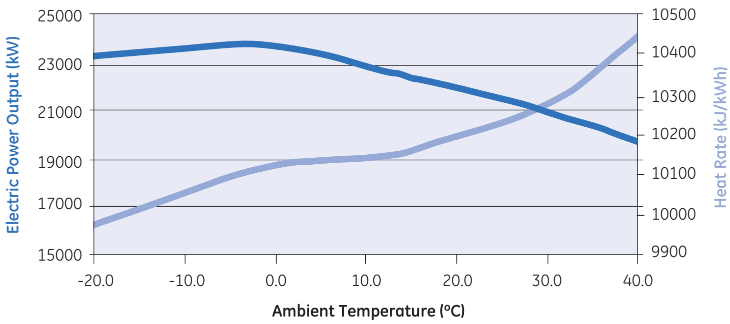
GE Power & Water is the world's largest aeroderivative service provider, with a global network of field service offices and fully-equipped service centers. A wide range of products and services are offered for the LM2500 and LM2000 Industrial, Cogeneration, and Oil & Gas operators including:

- Level IV Service Centers and overhaul capability in Houston, Texas and Rheden, the Netherlands.
- Conversions, Modifications and Upgrades (CM&Us) designed to enhance the efficiency, power output, and reliability of the LM2500. Examples include Exhaust Flow Enhancer, Wet/Dry Low Emissions (DLE) Upgrades, Inlet Conditioning, Fuel Conversions, and Remote Monitoring and Diagnostics.
- Spare or lease engine options.
- Engine exchange programs.
- Rotable hot section and module exchange programs.
- A wide variety of contractual or long-term service agreements.

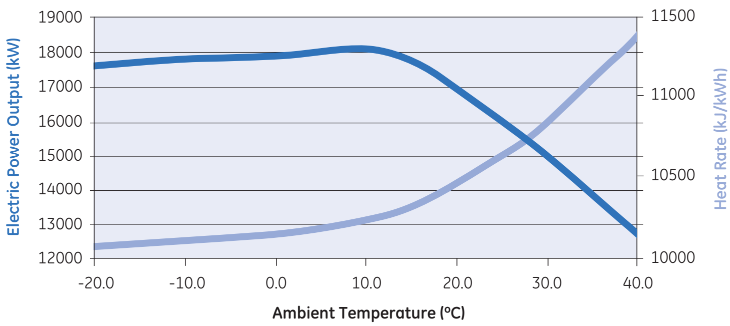
This comprehensive product offering, combined with GE's commitment to reduce service center and outage turn times, may result in substantial life-cycle cost savings for the plant owner/operator.

fact sheet

LM2500 50 Hz Output and Heat Rate



LM2000 50 Hz Output and Heat Rate



Notes: Performance based on 60% RH, sea level, no inlet/exhaust losses on natural gas fuel with no NO_X media. Average engine. Turbine inlet temp, exhaust flow and exhaust temp at ISO rating conditions. Generator output at 11.5 kV, 0.90 PF.

50 Hz LM2500 Generator Package

Gas Turbine

- 16-stage axial compressor
  — First six stages have Variable Stator Vanes (VSV)
  — Horizontal split casing
- Combustor Options
  — Gas, liquid, and dual fuel
  — Water or steam injection, or Dry Low Emissions (DLE) for NO_X control
- 6-stage power turbine
- Turbine factory tested

Generator

- Continuous duty 11.5 kV, 11.0 kV, or 10.5 kV
- TEWAC, TEEAC, or air-cooled options
- 2-pole, 3-phase brushless exciter
- WPII weather protected
- Voltage regulator and neutral side protection CTs
- NEMA Class F insulation and Class B temperature rise

Package

- 24 V and 125 V DC batteries
- 90 and 85 dBA near field design
- Barrier inlet air filters
- Inlet conditioning
  — Evaporative cooling
  — Chilling
  — Heating
- Electro-hydraulic start system
- CE/ATEX certification Ex II 3G
- Winterization to -39°C
- On/Off-line water wash
- 304SS or 316SS piping materials

Control System

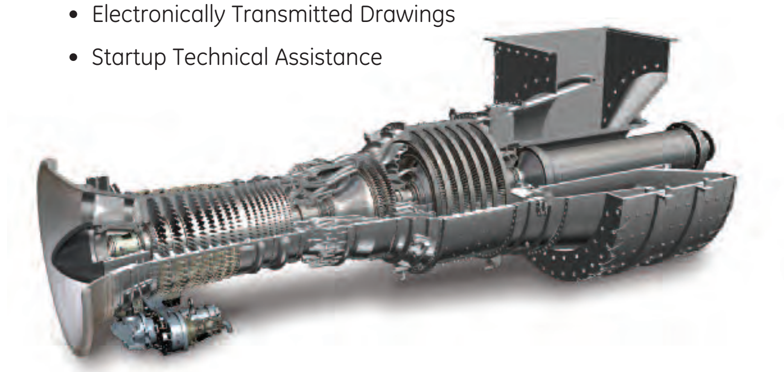
- Digital control system with a Human Machine Interface (HMI)
- 10-minute start capability to full load
- Black start
- Continuous emission monitoring
- Remote monitoring and diagnostics
- Remote display
- Control house
- Motor control center

Lube Oil System

- Air to oil coolers
- First fill lubricants
- Simplex shell and tube coolers

Support

- One-Year Parts/Service Warranty
- Package Familiarization Training
- Electronically Transmitted Drawings
- Startup Technical Assistance



www.gepower.com

GEA18145C (06/2013)

STANDBY 2000 ekW 2500 kVA

60 Hz 1800 rpm 480 Volts

TECHNICAL DATA

Open Generator Set - - 1800 rpm/60 Hz/480 Volts	DM8263	
EPA Certified for Stationary Emergency Application (EPA Tier 2 emissions levels)		
Generator Set Package Performance		
Genset Power rating @ 0.8 pf	2500 kVA	
Genset Power rating with fan	2000 ekW	
Fuel Consumption		
100% load with fan	522.5 L/hr	138.0 Gal/hr
75% load with fan	406.8 L/hr	107.5 Gal/hr
50% load with fan	293.6 L/hr	77.6 Gal/hr
Cooling System[1]		
Air flow restriction (system)	0.12 kPa	0.48 in. water
Air flow (max @ rated speed for radiator arrangement)	2480 m^3/min	87580 cfm
Engine Coolant capacity with radiator/exp. tank	475.0 L	125.5 gal
Engine coolant capacity	233.0 L	61.6 gal
Radiator coolant capacity	242.0 L	63.9 gal
Inlet Air		
Combustion air inlet flow rate	185.5 m^3/min	6550.9 cfm
Exhaust System		
Exhaust stack gas temperature	400.1 ° C	752.2 ° F
Exhaust gas flow rate	433.1 m^3/min	15294.8 cfm
Exhaust flange size (internal diameter)	203.2 mm	8.0 in
Exhaust system backpressure (maximum allowable)	6.7 kPa	26.9 in. water
Heat Rejection		
Heat rejection to coolant (total)	759 kW	43164 Btu/min
Heat rejection to exhaust (total)	1788 kW	101683 Btu/min
Heat rejection to aftercooler	672 kW	38217 Btu/min
Heat rejection to atmosphere from engine	133 kW	7564 Btu/min
Heat rejection to atmosphere from generator	85.5 kW	4862.4 Btu/min
Alternator[2]		
Motor starting capability @ 30% voltage dip	4999 skVA	
Frame	826	
Temperature Rise	105 ° C	189 ° F
Lube System		
Sump refill with filter	466.0 L	123.1 gal
Emissions (Nominal)[3]		
NOx g/hp-hr	5.45 g/hp-hr	
CO g/hp-hr	.3 g/hp-hr	
HC g/hp-hr	.11 g/hp-hr	
PM g/hp-hr	.025 g/hp-hr	

[1] For ambient and altitude capabilities consult your Cat dealer. Air flow restriction (system) is added to existing restriction from factory.

[2] Generator temperature rise is based on a 40 degree C ambient per NEMA MG1-32. UL 2200 Listed packages may have oversized generators with a different temperature rise and motor starting characteristics.

[3] Emissions data measurement procedures are consistent with those described in EPA CFR 40 Part 89, Subpart D & E and ISO8178-1 for measuring HC, CO, PM, NOx. Data shown is based on steady state operating conditions of 77ºF, 28.42 in HG and number 2 diesel fuel with 35º API and LHV of 18,390 btu/lb. The nominal emissions data shown is subject to instrumentation, measurement, facility and engine to engine variations. Emissions data is based on 100% load and thus cannot be used to compare to EPA regulations which use values based on a weighted cycle.

PERFORMANCE DATA[DM8263]

Performance Number: DM8263 **Change Level: 03**

SALES MODEL:	3516C
ENGINE POWER (BHP):	2,937
GEN POWER WITH FAN (EKW):	2,000.0
COMPRESSION RATIO:	14.7
APPLICATION:	PACKAGED GENSET
RATING LEVEL:	STANDBY
PUMP QUANTITY:	2
FUEL TYPE:	DIESEL
MANIFOLD TYPE:	DRY
GOVERNOR TYPE:	ADEM3
ELECTRONICS TYPE:	ADEM3
CAMSHAFT TYPE:	STANDARD
IGNITION TYPE:	CI
INJECTOR TYPE:	EUI
FUEL INJECTOR:	2664387
REF EXH STACK DIAMETER (IN):	12
MAX OPERATING ALTITUDE (FT):	3,117
COMBUSTION:	DI
ENGINE SPEED (RPM):	1,800
HERTZ:	60
FAN POWER (HP):	114.0
ASPIRATION:	TA
AFTERCOOLER TYPE:	ATAAC
AFTERCOOLER CIRCUIT TYPE:	JW+OC, ATAAC
INLET MANIFOLD AIR TEMP (F):	122
JACKET WATER TEMP (F):	210.2
TURBO CONFIGURATION:	PARALLEL
TURBO QUANTITY:	4
TURBOCHARGER MODEL:	GTA5518BN-56T-1.12
CERTIFICATION YEAR:	2006
CRANKCASE BLOWBY RATE (FT3/HR):	2,937.9
FUEL RATE (RATED RPM) NO LOAD (GAL/HR):	13.7
PISTON SPD @ RATED ENG SPD (FT/MIN):	2,244.1

General Performance Data

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	BRAKE MEAN EFF PRES (BMEP)	BRAKE SPEC FUEL CONSUMPTN (BSFC)	VOL FUEL CONSUMPTN (VFC)	INLET MFLD PRES	INLET MFLD TEMP	EXH MFLD TEMP	EXH MFLD PRES	ENGINE OUTLET TEMP
EKW	%	BHP	PSI	LB/BHP-HR	GAL/HR	IN-HG	DEG F	DEG F	IN-HG	DEG F
2,000.0	100	2,937	307	0.329	138.0	78.3	121.2	1,118.5	71.5	752.1
1,800.0	90	2,641	276	0.331	124.9	73.1	119.6	1,067.5	65.7	716.0
1,600.0	80	2,353	246	0.337	113.1	68.0	118.2	1,027.0	60.0	693.3
1,500.0	75	2,212	231	0.340	107.5	65.2	117.5	1,008.1	57.2	684.6
1,400.0	70	2,071	216	0.344	101.8	62.3	116.8	989.4	54.4	676.9
1,200.0	60	1,795	188	0.352	90.1	55.5	115.4	952.0	48.0	662.8
1,000.0	50	1,521	159	0.357	77.5	46.5	113.7	913.4	40.1	654.0
800.0	40	1,250	131	0.357	63.8	34.8	111.8	863.8	30.3	655.0
600.0	30	977	102	0.365	50.9	24.2	110.6	803.8	22.0	650.0
500.0	25	839	88	0.374	44.8	19.7	110.2	767.0	18.7	641.7
400.0	20	699	73	0.388	38.8	15.7	109.8	724.6	15.7	629.0
200.0	10	411	43	0.450	26.4	9.0	109.1	596.9	10.9	552.8

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	COMPRESSOR OUTLET PRES	COMPRESSOR OUTLET TEMP	WET INLET AIR VOL FLOW RATE	ENGINE OUTLET WET EXH GAS VOL FLOW RATE	WET INLET AIR MASS FLOW RATE	WET EXH GAS MASS FLOW RATE	WET EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)	DRY EXH VOL FLOW RATE (32 DEG F AND 29.98 IN HG)
EKW	%	BHP	IN-HG	DEG F	CFM	CFM	LB/HR	LB/HR	FT3/MIN	FT3/MIN
2,000.0	100	2,937	83	454.3	6,548.9	15,292.8	28,512.8	29,478.4	6,205.0	5,738.7
1,800.0	90	2,641	77	428.8	6,318.7	14,243.0	27,390.5	28,264.7	5,956.5	5,533.7
1,600.0	80	2,353	72	404.5	6,073.3	13,331.0	26,220.6	27,012.9	5,685.0	5,301.6
1,500.0	75	2,212	69	392.7	5,932.2	12,897.9	25,568.0	26,319.7	5,542.0	5,176.6
1,400.0	70	2,071	66	380.9	5,777.2	12,448.0	24,862.1	25,573.8	5,384.8	5,037.5
1,200.0	60	1,795	59	353.9	5,397.2	11,422.5	23,141.0	23,771.1	5,003.4	4,694.0
1,000.0	50	1,521	50	318.8	4,857.3	10,138.7	20,731.5	21,274.5	4,476.2	4,208.4
800.0	40	1,250	38	271.1	4,090.0	8,488.8	17,357.1	17,803.6	3,744.5	3,524.2
600.0	30	977	27	225.0	3,394.1	6,989.6	14,328.5	14,684.4	3,097.0	2,920.6
500.0	25	839	22	204.1	3,103.5	6,328.1	13,075.2	13,388.4	2,825.1	2,668.8
400.0	20	699	18	184.1	2,840.4	5,696.0	11,947.2	12,218.4	2,572.5	2,435.7
200.0	10	411	11	148.5	2,409.4	4,478.2	10,105.7	10,290.7	2,174.6	2,076.8

PERFORMANCE DATA[DM8263]

Heat Rejection Data

GENSET POWER WITH FAN	PERCENT LOAD	ENGINE POWER	REJECTION TO JACKET WATER	REJECTION TO ATMOSPHERE	REJECTION TO EXH	EXHUAST RECOVERY TO 350F	FROM OIL COOLER	FROM AFTERCOOLER	WORK ENERGY	LOW HEAT VALUE ENERGY	HIGH HEAT VALUE ENERGY
EKW	%	BHP	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN	BTU/MIN
2,000.0	100	2,937	43,150	7,564	101,696	49,615	15,778	38,240	124,558	296,234	315,563
1,800.0	90	2,641	40,179	7,175	92,069	43,106	14,280	34,105	111,977	268,102	285,596
1,600.0	80	2,353	37,427	6,907	84,225	38,510	12,931	30,201	99,774	242,774	258,615
1,500.0	75	2,212	36,092	6,791	80,632	36,523	12,286	28,303	93,784	230,664	245,715
1,400.0	70	2,071	34,737	6,671	77,064	34,629	11,640	26,432	87,835	218,548	232,809
1,200.0	60	1,795	31,877	6,341	69,432	30,722	10,302	22,179	76,103	193,426	206,048
1,000.0	50	1,521	28,631	6,026	60,835	26,675	8,865	17,129	64,508	166,434	177,294
800.0	40	1,250	24,910	5,810	50,784	22,387	7,288	11,280	53,005	136,837	145,766
600.0	30	977	21,252	5,496	41,420	18,139	5,820	6,677	41,431	109,268	116,397
500.0	25	839	19,405	5,303	37,082	16,055	5,124	4,986	35,574	96,210	102,488
400.0	20	699	17,492	5,098	32,738	13,986	4,431	3,593	29,634	83,193	88,622
200.0	10	411	13,286	4,670	23,481	8,473	3,022	1,516	17,448	56,745	60,447

PERFORMANCE DATA[DM8263]

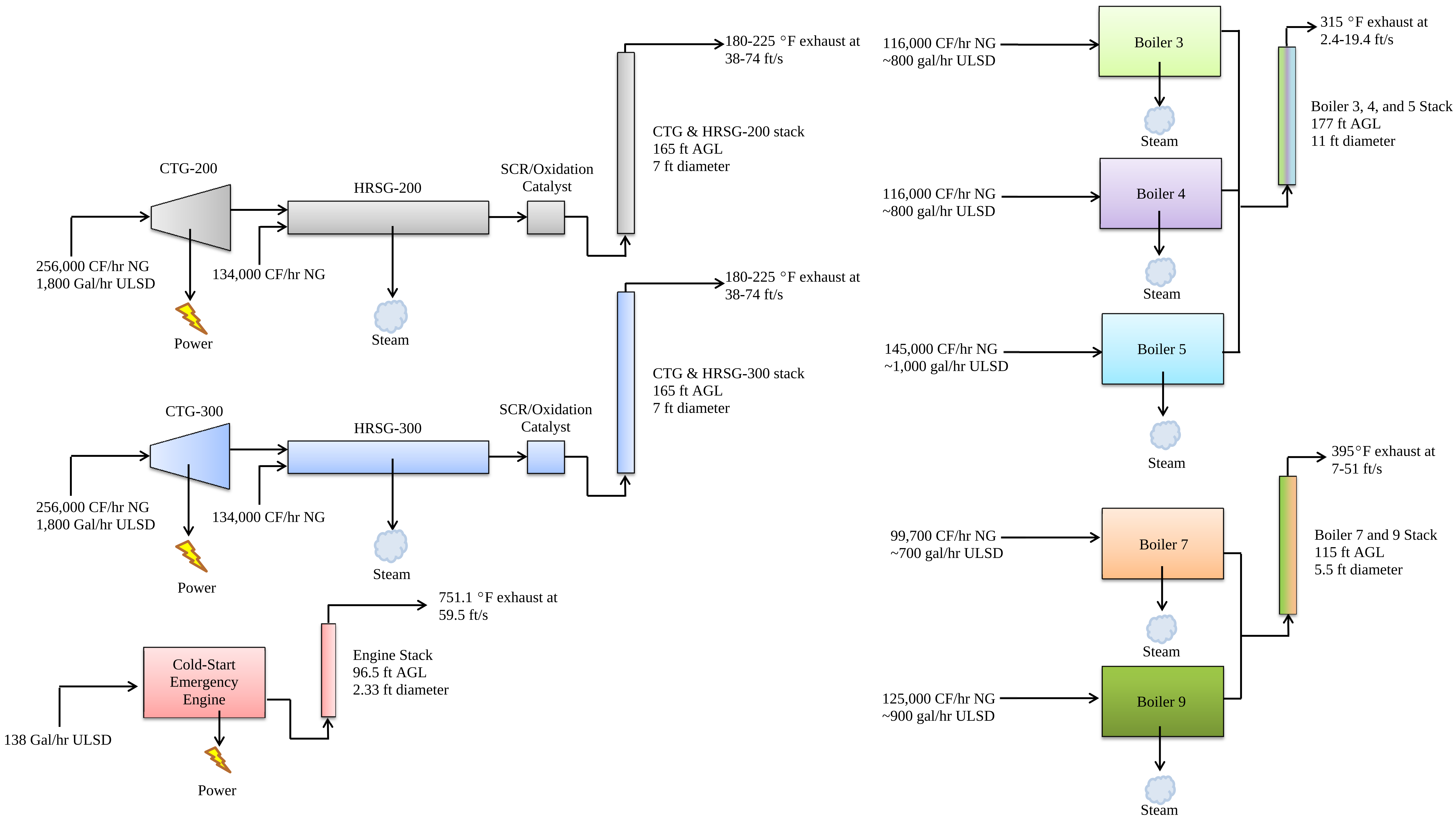
Emissions Data

RATED SPEED POTENTIAL SITE VARIATION: 1800 RPM

GENSET POWER WITH FAN		EKW	2,000.0	1,500.0	1,000.0	500.0	200.0
ENGINE POWER		**BHP**	**2,937**	**2,212**	**1,521**	**839**	**411**
PERCENT LOAD		**%**	**100**	**75**	**50**	**25**	**10**
TOTAL NOX (AS NO2)		G/HR	19,098	10,213	5,798	4,218	2,932
TOTAL CO		G/HR	1,564	847	905	1,772	1,794
TOTAL HC		G/HR	423	513	512	409	443
PART MATTER		G/HR	103.2	99.5	123.9	256.7	203.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	3,299.4	2,320.1	1,852.8	2,379.4	2,855.8
TOTAL CO	(CORR 5% O2)	MG/NM3	257.0	181.1	277.5	896.4	1,715.8
TOTAL HC	(CORR 5% O2)	MG/NM3	60.1	93.7	132.1	194.2	379.5
PART MATTER	(CORR 5% O2)	MG/NM3	14.4	18.5	35.1	120.0	161.3
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	1,607	1,130	902	1,159	1,391
TOTAL CO	(CORR 5% O2)	PPM	206	145	222	717	1,373
TOTAL HC	(CORR 5% O2)	PPM	112	175	247	363	708
TOTAL NOX (AS NO2)		G/HP-HR	6.54	4.64	3.82	5.04	7.13
TOTAL CO		G/HP-HR	0.54	0.38	0.60	2.12	4.36
TOTAL HC		G/HP-HR	0.15	0.23	0.34	0.49	1.08
PART MATTER		G/HP-HR	0.04	0.05	0.08	0.31	0.49
TOTAL NOX (AS NO2)		LB/HR	42.10	22.52	12.78	9.30	6.46
TOTAL CO		LB/HR	3.45	1.87	2.00	3.91	3.95
TOTAL HC		LB/HR	0.93	1.13	1.13	0.90	0.98
PART MATTER		LB/HR	0.23	0.22	0.27	0.57	0.45

RATED SPEED NOMINAL DATA: 1800 RPM

GENSET POWER WITH FAN		EKW	2,000.0	1,500.0	1,000.0	500.0	200.0
ENGINE POWER		**BHP**	**2,937**	**2,212**	**1,521**	**839**	**411**
PERCENT LOAD		**%**	**100**	**75**	**50**	**25**	**10**
TOTAL NOX (AS NO2)		G/HR	15,915	8,511	4,832	3,515	2,443
TOTAL CO		G/HR	869	471	503	984	997
TOTAL HC		G/HR	318	385	385	308	333
TOTAL CO2		KG/HR	1,383	1,068	762	430	250
PART MATTER		G/HR	73.7	71.1	88.5	183.4	145.1
TOTAL NOX (AS NO2)	(CORR 5% O2)	MG/NM3	2,749.5	1,933.4	1,544.0	1,982.8	2,379.8
TOTAL CO	(CORR 5% O2)	MG/NM3	142.8	100.6	154.2	498.0	953.2
TOTAL HC	(CORR 5% O2)	MG/NM3	45.2	70.4	99.3	146.0	285.3
PART MATTER	(CORR 5% O2)	MG/NM3	10.3	13.2	25.1	85.7	115.2
TOTAL NOX (AS NO2)	(CORR 5% O2)	PPM	1,339	942	752	966	1,159
TOTAL CO	(CORR 5% O2)	PPM	114	80	123	398	763
TOTAL HC	(CORR 5% O2)	PPM	84	131	185	273	533
TOTAL NOX (AS NO2)		G/HP-HR	5.45	3.87	3.19	4.20	5.94
TOTAL CO		G/HP-HR	0.30	0.21	0.33	1.18	2.42
TOTAL HC		G/HP-HR	0.11	0.18	0.25	0.37	0.81
PART MATTER		G/HP-HR	0.03	0.03	0.06	0.22	0.35
TOTAL NOX (AS NO2)		LB/HR	35.09	18.76	10.65	7.75	5.39
TOTAL CO		LB/HR	1.92	1.04	1.11	2.17	2.20
TOTAL HC		LB/HR	0.70	0.85	0.85	0.68	0.73
TOTAL CO2		LB/HR	3,049	2,356	1,681	947	551
PART MATTER		LB/HR	0.16	0.16	0.20	0.40	0.32
OXYGEN IN EXH		%	10.8	12.3	13.3	14.2	15.8
DRY SMOKE OPACITY		%	0.3	0.5	1.2	3.7	3.0
BOSCH SMOKE NUMBER			0.15	0.21	0.43	1.25	1.12


180-225 °F exhaust at
38-74 ft/s
CTG & HRSG-200 stack
165 ft AGL
7 ft diameter
CTG-200
HRSG-200
SCR/Oxidation
Catalyst
256,000 CF/hr NG
1,800 Gal/hr ULSD
134,000 CF/hr NG
Power
Steam
180-225 °F exhaust at
38-74 ft/s
CTG & HRSG-300 stack
165 ft AGL
7 ft diameter
CTG-300
HRSG-300
SCR/Oxidation
Catalyst
256,000 CF/hr NG
1,800 Gal/hr ULSD
134,000 CF/hr NG
Power
Steam
751.1 °F exhaust at
59.5 ft/s
Cold-Start
Emergency
Engine
Engine Stack
96.5 ft AGL
2.33 ft diameter
138 Gal/hr ULSD
Power
116,000 CF/hr NG
~800 gal/hr ULSD
Boiler 3
Steam
315 °F exhaust at
2.4-19.4 ft/s
Boiler 3, 4, and 5 Stack
177 ft AGL
11 ft diameter
116,000 CF/hr NG
~800 gal/hr ULSD
Boiler 4
Steam
145,000 CF/hr NG
~1,000 gal/hr ULSD
Boiler 5
Steam
395°F exhaust at
7-51 ft/s
99,700 CF/hr NG
~700 gal/hr ULSD
Boiler 7
Boiler 7 and 9 Stack
115 ft AGL
5.5 ft diameter
Steam
125,000 CF/hr NG
~900 gal/hr ULSD
Boiler 9
Steam

4.3 Particulate Matter BACT

This BACT analysis follows the guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, USEPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the NESCAUM BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual. This section updates a BACT analysis provided in October 2009 for Boiler #7.

4.3.1 BACT Applicability

> …the BACT determination must separately address…, for each regulated pollutant… air pollution controls for each emissions unit or pollutant emitting activity subject to review.

While "particulate matter" is listed as a regulated pollutant, EPA rescinded the national ambient air quality standard for particulate matter in favor of a PM10 standard in 1987, and recent statutory and regulatory provisions impose controls and limitations on PM10, not particulate matter.

Particulate matter consists of two broad categories: filterable PM and condensable PM. Based on a request from the MassDEP, this analysis addresses total particulate, filterable plus condensable.

PM2.5 is a subset of PM10; there is very limited data on PM2.5 emission limits achieved in practice, and there is considerable uncertainty regarding PM2.5 test methods. Much or most of the filterable PM10 emissions will be 2.5 microns or smaller, and all of the condensable PM10 emissions are generally considered 2.5 microns or smaller. BACT techniques for PM2.5 control will be the same as for PM10 control. For all of these reasons, this application makes the conservative assumption that all PM10 emitted from Boiler 7 is PM2.5. The BACT emission rates reviewed in this analysis are for PM, PM10 and PM2.5.

4.3.2 Step 1–Identify All Control Technologies

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion control, including:
  - Fabric filtration
  - Electrostatic precipitation
  - Wet scrubbing
  - Cyclone or multiclone collection
  - Side-stream separation
- The use of clean fuels and good combustion control

Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

The list above includes fuel combustion techniques, and the use of clean fuels which can be considered "fuel cleaning or treatment."

This includes technologies employed outside of the United States.

The list includes technologies employed outside the United States. MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

The use of clean fuels can be considered an inherently lower-polluting process.

The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

The source category in question is the production of steam in a package boiler. Existing particulate controls are limited to the use of clean fuels and good combustion techniques.

Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the post-combustion control options listed above.

Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

MIT has reviewed the EPA RACT/BACT/LAER Clearinghouse and other online data sources which include LAER determinations. All comparable determinations have been included in this analysis and can be found in Appendix E. The top control technology found is the use of clean fuels and good combustion techniques.

4.3.3 Step 2–Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically infeasible*

- Use of clean fuels and good combustion control: *technically feasible*

A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- Post-combustion control. All available post-combustion controls have a limitation to how clean an exhaust concentration they can achieve. The minimum outlet concentration achievable using post-combustion control is generally higher than the inlet concentration achievable using clean fuels. Therefore, the installation of post-combustion controls will not reduce particulate emissions.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

MIT has made a good faith effort to compile appropriate information from available information sources (per EPA guidance). Information sources considered included:

- EPA's RACT/BACT/LAER Clearinghouse and Control Technology Center - Information from the Clearinghouse[1] is included in Appendix E. No facilities are identified that use post-combustion control on a boiler that exclusively fires natural gas and/or distillate oil. Those data were reviewed and key identified facilities are presented below;

- Best Available Control Technology Guideline - South Coast Air Quality Management District - The Guideline[2] states that the California BACT guideline is the use of natural gas, with ULSD backup. Key pages are in Appendix E;

- Control technology vendors - An online review of vendors[3] does not find any offering post-combustion control for particulate matter from boilers firing natural gas or distillate oil;

1 http://cfpub.epa.gov/rblc/

2 http://aqmd.gov/bact/BACTGuidelines.htm

- Federal/State/Local new source review permits and associated inspection/performance test reports - a good faith effort to review permits available online found information as presented below;

- Environmental consultants - Consultants at Epsilon Associates, Inc. reviewed available information on current and past projects;

- Technical journals, reports and newsletters, air pollution control seminars - a review of papers posted by the Air and Waste Management Association[4] found no recent papers associated with particulate emission rates achievable from gas and ULSD-fired package boilers; and

- EPA's policy bulletin board - A review of the online OAR Policy and Guidance[5] websites found no references to specific recent BACT emission limits or technologies for particulate matter from gas and ULSD-fired package boilers. Particulate control from boilers was reviewed in the development of the (vacated) NESHAPs for industrial, commercial, and institutional boilers under 40 CFR 63[6]. EPA concluded that, for boilers firing gaseous fuel with liquid fuel backup, "no existing units were using control technologies that achieve consistently lower emission rates than uncontrolled sources."

From a review of the data sources listed above the comparable projects are found, as described in additional detail in Appendix E. The EPA Clearinghouse was queried for boilers firing natural gas or distillate oil, that are sized between 50 and 200 MMBtu/hr, that do not fire solid fuels or residual oil, and that do not serve some other industrial purpose (such as controlling emissions from another process). Facilities listed in the Clearinghouse as having only filterable particulate matter limits were excluded. Additional facilities were added based on Epsilon experience.

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3 http://www.icac.com/custom/buyers_guide/Find_Technologies.cfm, search for particulate matter control equipment. Three technologies and fourteen vendor websites reviewed September 2009, spot check for updates September 2010.

4 http://secure.awma.org/onlinelibrary/AdvancedSearch.aspx, September 2010. Searches for "Particulate & Natural Gas" and "Particulate & Distillate." No applicable papers were identified.

5 http://epa.gov/ttn/oarpg/new.html and http://epa.gov/ttn/oarpg/ramain.html.

6 http://epa.gov/ttn/atw/boiler/boilerpg.html

No comparable projects were found that used post-combustion control. Key projects are summarized as follows:

Table 4-2 Comparable Projects – Gas-fired

Facility	Boiler Size	PM limit	Notes
CPV St Charles, MD	93 MMBtu/hr	0.005 lb/MMBtu	Not yet constructed. LAER determination. Licensing conditions indicate no testing required.
Central Soya, OH	91.2 MMBtu/hr	0.005 lb/MMBtu	Based on vendor testing; permit indicates no testing required.
AES Red Oak, NJ	120 MMBtu/hr	0.0066 lb/MMBtu	Based on permit issuance date (1/00), condensables may not be required
Cargill, IN	75 MMBtu/hr	0.007 lb/MMBtu	Uses AP-42 emission factors; permit indicates not a specific limit, no testing.
CPV Cunningham, VA	80 MMBtu/hr	0.007 lb/MMBtu	Permit has lb/hr limit, no condensables, no testing
Sithe Mystic, MA	96 MMBtu/hr	0.007 lb/MMBtu	Based on permit age & Epsilon experience, does not include condensables.
Dalkia Kendall, MA	2 boilers 155 MMBtu/hr	0.007 lb/MMBtu	Permit includes condensables & testing
Ameripol, TX	54 MMBtu/hr	0.007 lb/MMBtu	Compliance based on use of natural gas. Based on permit age, no condensables included.
Lawrenceburg, IN	124.6 MMBtu/hr	0.007 lb/MMBtu	Permit indicates lb/hr limit, including condensables, no testing required.
Ace Ethanol, WI	60 MMBtu/hr, 80 MMBtu/hr	0.0075 lb/MMBtu	Permit does not require testing.
Nucor Decatur, AL	95 MMBtu/hr	0.0076 lb/MMBtu	Permit indicates Method 5 (filterable) only, no testing required.
Emergy Generating, IA	68 MMBtu/hr	0.0076 lb/MMBtu	Likely based on AP-42 emission factors; Permit indicates no testing required.
Mankato, MN	70 MMBtu/hr	0.008 lb/MMBtu	Permit does not indicate that condensables are included; no testing required.
Alabama Theodore, AL	220 MMBtu.ht	0.008 lb/MMBtu	Based on permit issuance date (1999), condensables not required
Minnesota Corn Processors, MN	237.4 MMBtu/hr	0.0084 lb/MMBtu	Based on permit issuance date (1999), condensables not required
GenPower Rincon, GA	83 MMBtu/hr	0.0084 lb/MMBtu	Permit indicates Method 5 (filterable) only, no testing required.
MIT Boiler #7, Cambridge MA	99.7 MMBtu/hr	0.01 lb/MMBtu	Per 1/19/10 MassDEP approval, adjacent to proposed Boiler #9. Includes condensables.
VCU East, VA	3 boilers 150 MMBtu/hr each	0.01 lb/MMBtu	Permit & permit memo do not indicate that condensables are included; no testing required.
UMass Amherst, MA	4 boilers 162-180 MMBtu/hr	0.02 lb/MMBtu	Permit includes condensables & testing

Table 4-2 Comparable Projects – Gas-fired (Continued)

Facility	Boiler Size	PM limit	Notes
Titan Tire, OH	50.4 MMBtu/hr	0.02 lb/MMBtu	Permit indicates compliance using AP-42, no testing.
Port Hudson, LA	65.5 MMBtu/hr	0.05 lb/MMBtu	Higher than proposed BACT
Bridgestone Firestone, NC	121 MMBtu/hr	0.24 lb/MMBtu	BACT not applied

Table 4-3 Comparable Projects – Oil-fired

Facility	Boiler Size	PM limit	Notes
Central Soya, OH	91.2 MMBtu/hr	0.0054 lb/MMBtu	Based on vendor testing; permit indicates no testing required.
VCU East, VA	3 boilers 150 MMBtu/hr each	0.022 lb/MMBtu	Permit & permit memo do not indicate that condensables are included; no testing required.
UMass Amherst, MA	4 boilers 156-173 MMBtu/hr	0.03 lb/MMBtu	Permit includes condensables & testing
MIT Boiler #7, Cambridge MA	99.7 MMBtu/hr	0.03 lb/MMBtu	Per 1/19/10 MassDEP approval, adjacent to proposed Boiler #9. Includes condensables.
Dalkia Kendall, MA	2 boilers 155 MMBtu/hr	0.04 lb/MMBtu	Permit includes condensables & testing
AES Red Oak, NJ	120 MMBtu/hr	0.04 lb/MMBtu	Based on permit issuance date (1/00), condensables likely not required
TECO Polk, FL	120 MMBtu/hr	0.1 lb/MMBtu	Filterable only, testing required

4.3.4 Step 3–Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

The only remaining control technology is the use of clean fuels and clean combustion. Requested data is summarized below.

Control efficiencies (percent pollutant removed)	Not applicable (inherently clean technology used)
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C, potential emissions are 1.25 lb/hr firing gas, 3.60 lb/hr firing ULSD, and 3.1 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	Not applicable (inherently clean technology used)
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels.
Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of boiler efficiency; Boiler #9 is an efficient modern boiler with low energy impacts.

4.3.4 Step 4&5–Select BACT

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

Consistent with the analysis presented above, MIT proposes the use of a clean fuels, and clean combustion, achieving a total PM/PM10/PM2.5 emission rate of 0.01 lb/MMBtu firing gas and 0.03 lb/MMBtu firing ULSD as the top alternative for BACT. These limits are consistent with Boiler #7, and comparable to recent Massachusetts projects of similar size, Dalkia (0.007 lb/MMBtu gas, 0.04 lb/MMBtu oil), and UMass Amherst (0.02 lb/MMBtu gas, 0.03 lb/MMBtu oil). The proposed BACT emission limitations are the maximum degree of reduction achievable, taking into account the scarcity of comparable units with emission limits demonstrated-in-practice, the continued concerns with the accuracy & repeatability of the stack test method (EPA Method 202), and the limited technical opportunities to directly control and reduce particulate emissions.

4.6 Carbon Dioxide BACT

This BACT analysis follows the guidance in the New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, USEPA Draft October 1990 document. Specific guidance from that document is included in boxes below, followed by MIT's analysis based on the guidance. The BACT analysis follows the guidance in the NESCAUM BACT Guideline dated June 1991, as well as the referenced NSR Workshop Manual.

The status of carbon dioxide (CO2) as an air contaminant subject to BACT per 310 CMR 7.02(8)(a)2 is in transition. MIT is submitting this BACT analysis at MassDEP's request.

4.6.1 Step 1–Identify All Control Technologies

> The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation.

Available control options are:

- Post-combustion capture and sequestration, including:
  - Capture: Amine solvent scrubbing
  - Capture: Cryogenic cooling
  - Sequestration: Injection into deep wells
  - Sequestration: Deep sea injection
- The use of clean fuels and efficient combustion

> Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

The list above includes the use of clean fuels which can be considered "fuel cleaning or treatment." The EPA guidance states:

> "EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity)."

It is therefore not appropriate to analyze the choice of project type as part of this CO2 BACT analysis. The choice of project type is the use of a package boiler to provide steam for distribution through the Central Utility Plant to the MIT buildings serviced by the Central Utility Plant.

> This includes technologies employed outside of the United States.

The list includes technologies employed outside the United States. MIT is unaware of technologies employed outside the United States that are not employed inside the United States.

> As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives.

The use of clean fuels can be considered an inherently lower-polluting process.

> The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies.

The source category in question is the production of steam in a package boiler. Existing controls are limited to the use of clean fuels and good combustion techniques.

Through technology transfer, controls applied to similar source categories (residual oil or solid fuel combustion) include the post-combustion control options listed above.

> Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

There are no LAER determinations for CO2. Federal New Source Review requirements do not currently apply to CO2, and there are no CO2 nonattainment areas where LAER would apply.

4.6.2 Step 2–Eliminate Technically Infeasible Options

> In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors.

Each identified control option is evaluated with respect to emissions unit-specific factors below.

- Post-combustion control: *technically infeasible*
- Use of clean fuels and good combustion control: *technically feasible*

> A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Clear documentation of technical difficulties is demonstrated below for each technically infeasible control option:

- ♦ **Post-combustion control**. Add-on controls for carbon dioxide recovery and sequestration is not feasible for this project. Available recovery techniques (e.g. scrubbing with monoethanolamine) work best on concentrated, cool, steady exhaust streams; Boiler 7 will have a dilute, hot, intermittent exhaust stream. Available sequestration techniques include injection into deep wells (such as oil wells) or deep sea injection; neither option is available on-site. Further, space limitations preclude installing CO2 recovery on Boiler 9.

> For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration.

Based on a good faith effort to compile appropriate information from available information sources, no information on CO2 emission limits was found. Information sources considered included:

- ♦ The RACT/BACT/LAER Clearinghouse (RBLC)[7]: EPA's main data center for BACT analyses does not include CO2 emissions.

- ♦ Recent permits issued by the DEP: Recent permits issued do not include CO2 limits (e.g. MIT Boiler 7 1/19/10, Dalkia Kendall 1/03/2007, Mystic Aux Boilers 4/25/2007, Lowell Power 1/22/2008, Braintree Electric Light Department 3/14/2008, Russell Biomass 12/30/2008).

- ♦ State Implementation Plan (SIP) limits for that particular class or category of sources; MIT is not aware of any SIP limits for CO2 emissions from package steam boilers. The Massachusetts 7.29 rule regulates CO2 emissions from certain power plants; those regulations do not apply to MIT and in any event Boiler 9 emissions are well below the limitation[8];

- ♦ South Coast Air Quality Management District BACT Determinations[9] do not include any CO2 limits;

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[7] http://cfpub.epa.gov/rblc

[8] 310 CMR 7.29(5)(a)5 limits certain large existing power plants to 1800 lb CO2/MW-hr, and provides a method to offset excess emissions.

[9] http://www.aqmd.gov/bact/AQMDBactDeterminations.htm

- California Air Resource Board's ("CARB") BACT Clearinghouse Database[10] do not include any CO2 limits; and
- Bay Area Air Quality Management District BACT Workbook does not include any guidance on CO2 emissions.[11]

4.6.3 Step 3–Rank Remaining Control Technologies By Control Effectiveness

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

The only remaining control technology is the use of clean fuels and clean combustion. Requested data is summarized below.

Control efficiencies (percent pollutant removed)	Not applicable (inherently clean technology used)
Expected emission rate (tons per year, pounds per hour)	Using US Department of Energy emission factors, potential emissions are ~14,600 lb/hr firing gas, ~20,200 lb/hr firing ULSD, and ~28,000 tons/year combined total. Expected tons/year emission rates are lower.
Expected emissions reduction (tons per year)	Not applicable (inherently clean technology used)
Economic impacts	In most cases, clean fuels are more expensive than higher-polluting fuels.

10 http://www.arb.ca.gov/bact/bact.htm

11 http://www.baaqmd.gov/pmt/bactworkbook/default.htm

Environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants)	The use of clean fuels can have lower water, wastewater, solid waste, and toxic/hazardous air impacts than higher-polluting fuels.
Energy impacts	Energy use is a function of boiler efficiency; Boiler 9 is a modern boiler with low energy impacts.

4.6.4 Step 4&5–Select BACT

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

The Massachusetts definition of BACT in 310 CMR 7.00 states that BACT "may include a design feature, equipment specification, work practice, operating standard, or combination thereof." MIT proposes that BACT for this project is the work practice of firing natural gas and ULSD, and the design feature of using a modern boiler.

Epsilon has looked into comparisons of the proposed Boiler #9 with similar boilers, on a pounds-CO2-per-pound-steam basis. The existing MIT Boiler #7 (Indeck Type D) boiler calculated CO2 emissions are 0.2 pounds per pound of steam when firing natural gas, and 0.25 pounds per pound of steam when firing distillate oil. For online research, a similar Johnston PTFS boiler would emit 0.19 pounds CO2 per pound of steam firing natural gas, and 0.24 pounds CO2 per pound of steam firing distillate oil. Limited information is available online to perform an apples-to-apples comparison of boiler CO2 emission rates; this comparison is presented on a best-efforts basis.

The proposed Boiler #9 will produce less than 0.2 pounds of CO2 per pound of steam when firing gas, and less than 0.25 pounds of CO2 per pound of steam when firing ULSD. That is in the range of modern good-efficiency package boilers.

APPENDIX C

Supporting Calculations

MIT turbine & duct burner model cases per turbine
Epsilon 12/2015

New Case Number	I.a	I.b	I.c	I.d	I. e	I. f	I. g	I. h	I. i	I. j
Old Case Number	3	4	7	7B	7A	8	10	11	12	13
Ambient Temp (F)	60	0	60	60	60	0	0	0	60	0
% Load	100	100	50	25	75	50	100	75	50	50
Turbine Fuel	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Turbine Fuel Input (MMBtu/hr, LHV)	230.6	231	133	90	178	134	233	182	134	135
Duct Burner Fuel Input (MMBtu/hr, LHV)	112.7	121.1	84.5	29.0	109.9	90.8	121.1	109.89	84.5	90.8
Turbine Fuel Input (MMBtu/hr, HHV)	255.74	255.74	147.94	99.81	197.85	148.94	247.68	193.47	142.87	143.93
Duct Burner Fuel Input (MMBtu/hr, HHV)	124.98	134.30	93.74	32.16	121.87	100.72	134.30	121.87	93.74	100.72
	HRSG EXHAUST		HRSG EXHAUST				HRSG EXHAUST			
Stack Exit Temp. (F)	180	180	180	180	180	180	225	225	225	225
Stack Flow Rate (ft3/min)	151,371	157,717	99,803	87,312	134,264	111,944	170,077	142,888	120,274	127,457
Turbines operating	1	1	1	1	1	1	1	1	1	1
Stack Emissions - Turbine Contribution										
CO	2 ppm	2 ppm	5 ppm	5 ppm	2 ppm	5 ppm	7 ppm	7 ppm	7 ppm	7 ppm
NOx	2 ppm	2 ppm	3.2 ppm	4 ppm	3.2 ppm	4 ppm	9 ppm	9 ppm	9 ppm	9 ppm
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu
SO2	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Duct Burner Contribution										
CO	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
NOx	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu
SO2	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Turbine Contribution										
CO (lb/hr)	1.21	1.21	1.75	1.18	0.94	1.76	4.10	3.20	2.37	2.38
Nox (lb/hr)	1.99	1.99	1.84	1.55	2.46	2.32	8.66	6.77	5.00	5.04
PM (lb/hr)	5.11	5.11	2.96	2.00	3.96	2.98	9.91	7.74	5.71	5.76
SO2 (lb/hr)	7.31E-01	7.31E-01	4.23E-01	2.85E-01	5.65E-01	4.26E-01	3.85E-01	3.01E-01	2.22E-01	2.24E-01
Stack Emissions - Duct Burner Contribution										
CO (lb/hr)	1.37	1.48	1.03	0.35	1.34	1.11	1.48	1.34	1.03	1.11
Nox (lb/hr)	1.37	1.48	1.03	0.35	1.34	1.11	1.48	1.34	1.03	1.11
PM (lb/hr)	2.50	2.69	1.87	0.64	2.44	2.01	2.69	2.44	1.87	2.01
SO2 (lb/hr)	0.36	3.84E-01	2.68E-01	9.19E-02	3.48E-01	2.88E-01	2.09E-01	1.89E-01	1.46E-01	1.57E-01
Stack Emissions - Total										
CO (lb/hr)	2.58	2.69	2.78	1.53	2.28	2.87	5.58	4.54	3.40	3.49
Nox (lb/hr)	3.36	3.47	2.87	1.91	3.80	3.42	10.14	8.11	6.03	6.14
PM (lb/hr)	7.61	7.80	4.83	2.64	6.39	4.99	12.59	10.18	7.59	7.77
SO2 (lb/hr)	1.09	1.11	0.69	0.38	0.91	0.71	0.59	0.49	0.37	0.38
Effective Stack Diameter (ft)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Area (ft2)	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5	38.5
Exit Velocity (ft/sec)	65.6	68.3	43.2	37.8	58.1	48.5	73.7	61.9	52.1	55.2
Exit Velocity (m/sec)	20.0	20.8	13.2	11.5	17.7	14.8	22.5	18.9	15.9	16.8

MIT turbine & duct burner model cases per turbine
Epsilon 12/2015

New Case Number	2.a	2.b	2.c	2.d	2. e	2. f	2. g	2. h	2. i	2. J
Old Case Number	3	4	7	7B	7A	8	10	11	12	13
Ambient Temp (F)	60	0	60	60	60	0	0	0	60	0
% Load	100	100	50	25	75	50	100	75	50	50
Turbine Fuel	NG	NG	NG	NG	NG	NG	ULSD	ULSD	ULSD	ULSD
Duct Burner Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG	NG
Turbine Fuel Input (MMBtu/hr, LHV)	231	231	133	90	178	134	233	182	134	135
Duct Burner Fuel Input (MMBtu/hr, LHV)	112.7	121.1	84.5	29.0	109.9	90.8	121.1	109.89	84.5	90.8
Turbine Fuel Input (MMBtu/hr, HHV)	255.74	255.74	147.94	99.81	197.85	148.94	247.68	193.47	142.87	143.93
Duct Burner Fuel Input (MMBtu/hr, HHV)	124.98	134.30	93.74	32.16	121.87	100.72	134.30	121.87	93.74	100.72
	HRSG EXHAUST		HRSG EXHAUST				HRSG EXHAUST			
Stack Exit Temp. (F)	180	180	180	180	180	180	225	225	225	225
Stack Flow Rate (ft3/min)	151,371	157,717	99,803	87,312	134,264	111,944	170,077	142,888	120,274	127,457
Turbines operating	2	2	2	2	2	2	2	2	2	2
Stack Emissions - Turbine Contribution										
CO	2 ppm	2 ppm	5 ppm	5 ppm	2 ppm	5 ppm	7 ppm	7 ppm	7 ppm	7 ppm
NOx	2 ppm	2 ppm	3.2 ppm	4 ppm	3.2 ppm	4 ppm	9 ppm	9 ppm	9 ppm	9 ppm
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu	0.04 lb/MMBtu
SO2	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Duct Burner Contribution										
CO	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
NOx	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu	0.011 lb/MMBtu
PM	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu	0.02 lb/MMBtu
SO2	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	1 grain/SCF	15 ppmw	15 ppmw	15 ppmw	15 ppmw
Stack Emissions - Turbine Contribution (per Turbine)										
CO (lb/hr)	1.21	1.21	1.75	1.18	0.94	1.76	4.10	3.20	2.37	2.38
Nox (lb/hr)	1.99	1.99	1.84	1.55	2.46	2.32	8.66	6.77	5.00	5.04
PM (lb/hr)	5.11	5.11	2.96	2.00	3.96	2.98	9.91	7.74	5.71	5.76
SO2 (lb/hr)	7.31E-01	7.31E-01	4.23E-01	2.85E-01	5.65E-01	4.26E-01	3.85E-01	3.01E-01	2.22E-01	2.24E-01
Stack Emissions - Duct Burner Contribution (per Turbine)										
CO (lb/hr)	1.37	1.48	1.03	0.35	1.34	1.11	1.48	1.34	1.03	1.11
Nox (lb/hr)	1.37	1.48	1.03	0.35	1.34	1.11	1.48	1.34	1.03	1.11
PM (lb/hr)	2.50	2.69	1.87	0.64	2.44	2.01	2.69	2.44	1.87	2.01
SO2 (lb/hr)	3.57E-01	3.84E-01	2.68E-01	9.19E-02	3.48E-01	2.88E-01	3.84E-01	3.48E-01	2.68E-01	2.88E-01
Stack Emissions - Total (from both Turbines)										
CO (lb/hr)	5.17	5.37	5.56	3.07	4.55	5.74	11.16	9.09	6.79	6.98
Nox (lb/hr)	6.73	6.93	5.74	3.81	7.60	6.85	20.28	16.22	12.06	12.29
PM (lb/hr)	15.23	15.60	9.67	5.28	12.79	9.99	25.19	20.35	15.18	15.54
SO2 (lb/hr)	2.18	2.23	1.38	0.75	1.83	1.43	1.54	1.30	0.98	1.02
Effective Stack Diameter (ft)	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Area (ft2)	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0	77.0
Exit Velocity (ft/sec)	65.6	68.3	43.2	37.8	58.1	48.5	73.7	61.9	52.1	55.2
Exit Velocity (m/sec)	20.0	20.8	13.2	11.5	17.7	14.8	22.5	18.9	15.9	16.8

MIT turbine & duct burner model cases
Epsilon 12/2015

New Case Number	I. Annual	II. Annual	
Old Case Number	7A	7A	
Ambient Temp (F)	60	60	
% Load	75	75	
Turbine Fuel	NG	NG	
Duct Burner Fuel	NG	NG	
Turbine Fuel Input (MMBtu/hr, LHV)	178	178	
Duct Burner Fuel Input (MMBtu/hr, LHV)	109.89	109.9	
Turbine Fuel Input (MMBtu/hr, HHV)	197.85	197.85	
Duct Burner Fuel Input (MMBtu/hr, HHV)	121.87	121.87	
	HRSG EXHAUST		
Stack Exit Temp. (F)	180	180	
Stack Flow Rate (ft3/min)	134,264	268,529	
Turbines operating	1	2	
Max hours operating ULSD	168	168	
Stack Emissions - Total			
CO (lb/hr)	2.83	5.67	168 hours ULSD at 100% load, 0F, remaining natural gas at 50% load, 60 F
Nox (lb/hr)	3.92	7.85	168 hours ULSD at 100% load, 0F, remaining natural gas at 75% load, 60 F
PM (lb/hr)	7.71	15.42	168 hours ULSD at 100% load, 0F, remaining natural gas at 100% load, 60 F
SO2 (lb/hr)	1.09	2.18	8760 hours natural gas at 100% load, 60F
Effective Stack Diameter (ft)	7.0	9.9	
Area (ft2)	38.5	77.0	
Exit Velocity (ft/sec)	58.1	58.1	
Exit Velocity (m/sec)	17.7	17.7	

Emissions Unit	Boiler 3, 4, 5		Boilers 7&9		Turbine #1	Generator	Cold start Engine
Case	**Full Load**	**Minimum Load**	**Full Load (Boiler 7&9)**	**Full Load (Boiler 9 Only)**	**Full Load**	**Full Load**	**Full Load**
Exit Temperature (F)	315	270	393	315	270	963	751.1
Exit Velocity (m/s)	5.91	0.73	17.68	8.06	35.79	61.94	18.15
Exhaust Flow (ACFM)	110,532	13,653	82,665	37,686	199,149	17,191	15,274
Stack Height (Ft)	177	177	115	115	120	63.75	96.5
Stack Diameter (ft)	11	11	5.5	5.5	6	1.34	2.33
Short-Term Emission Rate							
CO (lb/hr)	15.10	1.86	7.7	4.17	6.95	2.2	2.20
NOx (lb/hr)	113.28	13.94	16.59	11.92	46.6	1.175	35.1
PM10 (lb/hr)	20.77	2.56	6.59	3.58	13.94	0.76	0.400
PM2.5 (lb/hr)	20.77	2.56	6.59	3.58	13.94	0.76	0.400
SO2 (lb/hr)	0.57	0.07	0.33	0.18	0.470	0.032	0.029
Short-Term Emission Rate							
CO (lb/mmbtu)	See Below						
NOx (lb/mmbtu)							
PM10 (lb/mmbtu)							
PM2.5 (lb/mmbtu)							
SO2 (lb/mmbtu)							

MMBTU/hr	377.6	46.5
Boiler 3	116.2	46.5
Boiler 4	116.2	
Boiler 5	145.2	

Op Permit (Lb/mmbtu)	Boiler 3 - Oil	Boiler 4 - Oil	Boiler 5 - Oil
CO	0.04	0.04	0.04
NOx	0.3	0.3	0.3
PM10	0.055	0.055	0.055
PM2.5	0.055	0.055	0.055
SO2	0.0015	0.0015	0.0015

MIT
2 MW Cold-Start Engine Emission Calculations & Model Inputs
Epsilon 12/2015

Based on sample information for a CAT DM8263, 100% load

751.1	F engine outlet temperature
751.1	**F stack temperature (assumed no temperature loss)**

6,205	ft3/min wet exhaust volume at 32F
15,274	ft3/min wet exhaust volume at stack temperature, converted from above

28	**inches stack diameter from prior design**
59.53	**feet/second exhaust velocity**

35.09	**pounds/hour NOx (max across loads, nominal data)**
2.2	**pounds/hour CO (max across loads, nominal data)**
0.4	**pounds/hour PM (max across loads, nominal data)**

138	gal/hour ULSD use
7	lb/gal ULSD density, estimated
966	lb/hr ULSD use
0.0015%	weight percent sulfur in ULSD
2	pounds SO2/pound sulfur
0.029	**pounds/hour SO2 (max across loads)**

1.13	pounds/hour UHC (max across loads)
100%	UHC is VOC (conservative)
1.13	**pounds/hour VOC (max across loads, nominal data)**

0.139	MMBtu/gal estimated heat content of ULSD
19.182	MMBtu/hr
166	lb CO2/MMBtu emission rate for liquid fuel
3184	**lb/hr CO2**

Emissions Unit	Boiler 3, 4, 5		Boilers 7&9		Turbine #1	Generator	Cold start Engine
Case	Full Load	Minimum Load	Full Load (Boiler 7&9)	Full Load (Boiler 9 Only)	Full Load	Full Load	Full Load
Exit Temperature (F)	315	270	393	315	270	963	751.1
Exit Velocity (m/s)	5.91	0.73	17.68	8.06	35.79	61.94	18.15
Exhaust Flow (ACFM)	110,532	13,653	82,665	37,686	199,149	17,191	15,274
Stack Height (Ft)	177	177	115	115	120	63.75	96.5
Stack Diameter (ft)	11	11	5.5	5.5	6	1.34	2.33
Short-Term Emission Rate (gas)							
CO (lb/hr)	13.29	1.63	2.58	1.43	6.95	0.0753	0.075
NOx (lb/hr)	76.24	9.39	2.75	1.58	24.83	1.1750	1.202
PM10 (lb/hr)	11.51	1.42	2.34	1.30	4.98	0.0260	0.014
PM2.5 (lb/hr)	11.51	1.42	2.34	1.30	4.98	0.0260	0.014
SO2 (lb/hr)	0.57	0.07	0.33	0.18	0.47	0.0011	0.001
Short-Term Emission Rate							
CO (lb/mmbtu)	See Below		0.011	0.035			
NOx (lb/mmbtu)			0.011	0.1			
PM10 (lb/mmbtu)			0.01	0.03			
PM2.5 (lb/mmbtu)			0.01	0.03			
SO2 (lb/mmbtu)			0.0014	0.0015			

MMBTU/hr	377.6	46.5
Boiler 3	116.2	46.5
Boiler 4	116.2	
Boiler 5	145.2	
Hours on oil:	168	

Op Permit (Lb/mmbtu)	Boiler 3 - Gas	Boiler 4 - Gas	Boiler 5 - Gas
CO	0.035	0.035	0.035
NOx	0.2	0.2	0.2
PM10	0.03	0.03	0.03
PM2.5	0.03	0.03	0.03
SO2	0.0015	0.0015	0.0015

	B7 - gas	B9 - gas	B7 & 9 - gas	Boiler 3,4,5 NG	Boiler 3,4,5 ULSD+NG	Boiler 3,4,5 NG	Boiler 3,4,5 ULSD+NG
MMBTU/hr	99.70	125.80	225.50	MAX LOAD		MIN LOAD	
CO lb/MMBTU	0.0110	0.0110	--				
NOx lb/MMBTU	0.0110	0.0110	--				
PM10 lb/MMBTU	0.0100	0.0100	--				
PM2.5 lb/MMBTU	0.0100	0.0100	--				
SO2 lb/MMBTU	0.0014	0.0014	--				
CO lb/hr	1.10	1.38	2.48	13.250	**13.286**	1.627	**1.631**
NOx lb/hr	1.10	1.38	2.48	75.520	**76.244**	9.296	**9.385**
PM10 lb/hr	1.00	1.26	2.26	11.328	**11.509**	1.394	**1.417**
PM2.5 lb/hr	1.00	1.26	2.26	11.328	**11.509**	1.394	**1.417**
SO2 lb/hr	0.14	0.18	0.32	**0.566**	**0.566**	**0.070**	**0.070**

	B7 NG+ULSD	B9 NG+ULSD	B7 & 9 NG+ULSD	Turbine 1 - NG	Turbine 1 - NG + ULSD
MMBTU/hr	99.70	125.80	225.50	293.70	293.70
CO lb/hr	1.14	**1.43**	**2.58**	6.95	6.95
NOx lb/hr	1.17	**1.58**	**2.75**	24.40	24.83
PM10 lb/hr	1.04	**1.30**	**2.34**	4.80	4.98
PM2.5 lb/hr	1.04	**1.30**	**2.34**	4.80	4.98
SO2 lb/hr	0.14	0.18	0.32		

MIT PSD Increment Calculations
Epsilon 12/2015

INCREMENT EXPANDING																			
Source	**Max 24-hr Fuel Use (Gallons)**	**Date**	**Max 24-hr Gas Use (SCF)**	**Date**	**MMBTU/hr**	**lb/MMBTU (Gas)**	**lb/MMBTU (Oil)**	**Short-Term Gas**	**Short-term Oil**	**Short-Term PM25 Lb/hr**	**2013 NG Usage**	**2014 NG Gas Usage**	**2013 FO Usage**	**2014 FO Fuel Usage**	**Avg NG Use**	**Avg. FO Use**	**Total MMBTU NG**	**Total MMBTU Oil**	**Annual PM25 Lb/hr**
Boiler 3	13,213.65	12/31/2013	1,754,043	12/8/2014	116.2	0.0076	0.055	0.555	4.300	4.3	1.31E+08	9.81E+07	831357.50	512565.55	1.15E+08	6.72E+05	1.15E+05	9.54E+04	0.7
Boiler 4	19,948.17	2/6/2015	1,742,543	12/25/2013	116.2	0.0076	0.055	0.552	6.491	6.5	1.46E+08	9.23E+07	751592.04	816364.42	1.19E+08	7.84E+05	1.19E+05	1.11E+05	0.8
Boiler 5	17,284.04	2/6/2015	1,894,732	12/8/2014	145.2	0.0076	0.055	0.600	5.625	5.6	1.09E+08	1.25E+08	687889.95	1279725.14	1.17E+08	9.84E+05	1.17E+05	1.40E+05	1.0
Existing CT	43,976.00	1/24/2014	6,192,320	12/13/2013	229.0	0.007	0.040	1.806	10.114	10.1	1.55E+09	1.63E+09	783,368	600,400	1.59E+09	6.92E+05	1.59E+06	9.82E+04	1.7
Existing DB	-	-	1,190,100	4/2/2013	64.7	0.005	0.055	0.248	-	0.2	2.52E+08	2.34E+08	-	-	2.43E+08		2.43E+05		0.14
Boiler 7	9,162.62	2/24/2015	1,202,035	2/16/2015	99.7	0.010	0.030	0.501	1.581	1.6	7.70E+05	1.20E+07	342.6	21759.0	6.39E+06	1.11E+04	6.39E+03	1.57E+03	0.013
Boiler 9	10,209.70	2/24/2015	1,580,329	3/23/2015	100.0	0.010	0.030	0.658	1.761	1.8	6.84E+06	1.74E+07	4765.20	53813.50	1.21E+07	2.93E+04	1.21E+04	4.16E+03	0.028
Cooling Tower 1 per cell (2)										0.026									0.026
Cooling Tower 2 per cell (2)										0.026									0.026
Cooling Tower 3 per cell (2)										0.047									0.047
Cooling Tower 4 per cell (2)										0.041									0.041
Cooling Tower 5										0.017									0.017
Cooling Tower 6										0.017									0.017

MIT PSD Increment Calculations
Epsilon 12/2015

Source	Hrs/Yr Gas	Hrs/Yr Oil	NG Limit (lb/MMBTU)	Oil Limit (lb/MMBTU)	MMBTU/hr Gas	MMBTU/hr Oil	Short Term (lb/hr)	Annual (lb/hr)
Boiler 3		168	0.0076	0.055	116.2	116.2	0.56	0.30
Boiler 4		168	0.0076	0.055	116.2	116.2	0.55	0.32
Boiler 5		168	0.0076	0.055	145.2	145.2	0.60	0.38
Boiler 7	8592	168	0.01	0.03	99.7	99.7	0.50	1.0
Boiler 9	8592	168	0.01	0.03	125.8	119.2	0.66	1.3
CT1	8592	168	0.02	0.04	Based on the Results of the Load Analysis			
CT2	8592	168	0.02	0.04				
DB1	8760	0	0.02					
DB2	8760	0	0.02					
New Engine							0.400	0.014
Cooling Tower 11 per cell							0.035	0.035
Cooling Tower 12 per cell							0.035	0.035
Cooling Tower 13 per cell							0.035	0.035

MIT CHP Evaluation - Emissions Estimates

Epsilon 12/2015

	Nat. Gas	ULSD
CT Heat Input (MMBtu/hr LHV)	230.6	233.0
HHV/LHV conversion	1.109	1.063
CT Heat Input (MMBtu/hr HHV)	256	248
Duct Burner Heat Input (MMBtu/hr LHV)	121	121
Duct Burner Heat Input (MMBtu/hr HHV)	134	134
EPA F-Factor for natural gas, dscf/MMBtu	8,710	9,190

Turbine Emissions			
VOC ppmvd @15% O2 (as methane)	1.70	7.00	MassDEP Top-Case BACT Guidance
VOC ppmvd @ 0% O2	6	25	
VOC (as CH4) ideal gas conv., ppm to lb/scf	4.160E-08	4.160E-08	
VOC lb/MMBtu (HHV)(as methane)	0.0022	0.0095	
VOC lb/hr	0.56	2.35	
NH3 ppmvd @15% O2	2.00	2.00	MassDEP Top-Case BACT Guidance
NH3 ppmvd @ 0% O2	7	7	
NH3 ideal gas conv., ppm to lb/scf	4.41E-08	4.41E-08	
NH3/MMBtu (HHV)	0.0027	0.0029	
NH3 lb/hr	0.70	0.71	
CO2, lb/MMBtu	119	166	Consistency with recent applications
CO2, lb/hr	30433	41115	

Duct Burner Emissions			
VOC lb/MMBtu (HHV)(as methane)	0.03		MassDEP Top-Case BACT Guidance
VOC lb/hr (as methane)	4.03		
NH3 lb/MMBTU (HHV)	0.0027		same as turbine
NH3 lb/hr	0.37		
CO2, lb/MMBtu	119		Consistency with recent applications
CO2, lb/hr	15968		

Boiler 7					
99.7	MMBtu/hr				
8760	hours/year				
168	max hours/year on ULSD				
	lb/MMBtu NG	lb/MMBtu ULSD	Proposed ton/year	Current ton/year	Ton/year increase
CO	0.011	0.035	5.00	2.84	2.16
NOx	0.011	0.046	5.10	3.23	1.87
PM10/PM2.5	0.01	0.01	4.37	2.51	1.86
SO2	0.0014	0.0015	0.61	0.26	0.35
VOC	0.03	0.03	13.10	5.38	7.72
CO2	119	166	52359	23043	29317

Boiler 9					
125.8	MMBtu/hr (NG)				
119.2	MMBtu/hr (ULSD)				
8760	hours/year				
168	max hours/year on ULSD				
	lb/MMBtu NG	lb/MMBtu ULSD	Proposed ton/year	Current ton/year	Ton/year increase
CO	0.011	0.035	6.30	3.5	2.80
NOx	0.011	0.1	6.95	6.3	0.65
PM10/PM2.5	0.01	0.03	5.70	3.1	2.60
SO2	0.0014	0.0016	0.77	0.32	0.45
VOC	0.03	0.03	16.53	6.8	9.73
CO2	119	166	65974	28000	37974

Turbines					
255.74	MMBtu/hr HHV firing gas				
247.68	MMBtu/hr HHV firing ULSD				
124.98	MMBtu/hr HHV duct burner firing gas				
2	turbines				
168	hours/year ULSD				
4380	hours/year duct burner (estimate for calculating annual proposed emission limits)				
	Turbine lb/MMBtu NG	Turbine lb/MMBtu ULSD	Duct Burner lb/MMBtu NG		Ton/year
CO	0.0047	0.017	0.011		17.1
NOx	0.0078	0.035	0.011		24.6
PM10/PM2.5	0.02	0.040	0.020		56.6
SO2	0.0029	0.0016	0.0029		7.9
VOC	0.0022	0.0095	0.03		21.6
CO2	119	166	119		333528
NH3	0.0027	0.0029	0.0027		7.6

EDG					
300	hours/year				
	lb/hr				Ton/year
CO	2.2				0.33
NOx	35.09				5.26
PM10/PM2.5	0.4				0.060
SO2	0.029				0.0043
VOC	1.13				0.17
CO2	3184				478

Project Potential Emissions, tons/year						
	Turbines	EDG	Boiler 7	Boiler 9	Cool. towers	Total
CO	17.1	0.33	2.2	2.8	0	22.4
NOx	24.6	5.3	1.9	0.6	0	32.3
PM10/PM2.5	56.6	0.06	1.9	2.6	0.92	62.0
SO2	7.9	0.004	0.35	0.45	0	8.7
VOC	21.6	0.17	7.7	9.7	0	39.2
CO2	333527.7	478	29317	37974	0	401296
NH3	7.6	0	0	0	0	7.6

APPENDIX D

Technical Information

Technical Information

Facility Name: Massachusetts Institute of Technology

Street Address: 59 Vassar St., Building 42C, Cambridge MA 02139

Standard Industrial Classification (SIC) Code: 4931/8221

North American Industry Classification System (NAICS) Code: 611310

Contact Person: Ken Packard, kpackard@MIT.EDU, 617-253-4790

Responsible Official: William VanSchalkwyk, Managing Director, EHS Programs

Application Preparer: A.J. Jablonowski, Epsilon Associates, ajablonowski@epsilonassociates.com, 978-641-6202

Type of Project: Combined Heat and Power Combustion Turbine Installation

Project Description: Two nominal 22 MW Combustion Turbines (CT) with supplemental duct fired (134 MMBTU/hr) Heat Recovery Steam Generators (HRSGs), 3 cooling towers and one 2 MW IC engine.

Pollution Control Equipment: Selective Catalytic Reduction (~90% NOx Control); Oxidation Catalyst (~92% CO Control) on CT/HSRSGs.

Exhaust Parameters: Combustion turbine/HRSG (separate flues): Steel, 165 ft AGL 7 ft diameter, 180-225 °F exhaust at 38-74 ft/s

Cold Start Engine: Steel, 96.5 ft AGL, 2.33 ft diameter, 751.1 °F exhaust at 59.5 ft/s