PRINCIPALS

Theodore A Barten, PE
Margaret B Briggs
Michael E Guski, CCM
Dale T Raczynski, PE
Cindy Schlessinger
Lester B Smith, Jr
Robert D O'Neal, CCM, INCE
Andrew D Magee
Michael D Howard, PWS
Douglas J Kelleher
AJ Jablonowski, PE
Stephen H Slocomb, PE
David E Hewett, LEED AP

Samuel G. Mygatt, LLB
1943-2010

ASSOCIATES

Dwight R Dunk. LPD
David C. Klinch, PWS, PMP

3 Clock Tower Place, Suite 250
Maynard, MA 01754
www.epsilonassociates.com

978 897 7100
FAX 978 897 0099

December 15, 2015

Subject: MIT Central Utilities Plant Second Century Plant Expansion Expanded Environmental Notification Form

Dear Interested Party:

On behalf of the Proponent, the Massachusetts Institute of Technology (MIT), I am pleased to send you the enclosed Expanded Environmental Notification Form for the MIT Central Utilities Plant Second Century Plant Expansion, including the installation of two new nominal 22 MW Combustion Turbines with supplemental gas fired Heat Recovery Steam Generators as well as some changes to boiler operation, cooling towers, and a cold-start engine at 59 Vassar Street in Cambridge.

The Expanded ENF provides information on the project's expected environmental impacts, including a greenhouse gas analysis and a description of the available air plan approval application addressing air and noise impacts. As this Expanded ENF has been prepared to describe all aspects of the project and alternatives, provide a baseline to assess impacts and mitigation, and demonstrate that the project will use all feasible means to avoid environmental impacts, the Proponent is requesting that the Secretary of Energy and Environmental Affairs allow for the preparation of a Single Environmental Impact Report.

The Proponent expects that the Expanded ENF will be noticed in the *Environmental Monitor* on December 23, 2015 and that the comment period will end on January 22, 2016. Comments should be sent to:

Secretary, Matthew A. Beaton
Executive Office of Energy and Environmental Affairs
100 Cambridge Street, Suite 900
Boston MA 02114

If you have any questions about the project, please call me at (978) 461-6202.

Sincerely,

EPSILON ASSOCIATES, INC.

A.J. Jablonowski, PE
Principal

cc: Ken Packard, MIT

ENVIRONMENTAL NOTIFICATION FORM

Central Utilities Plant
Second Century Plant Expansion

Submitted to:
Executive Office of Energy
and Environmental Affairs
MEPA Office
100 Cambridge Street, Suite 900
Boston, MA 02114

Submitted by:
Massachusetts Institute of Technology
Building NE49, 2nd Floor
600 Technology Square
Cambridge, MA 02139

Prepared by:
Epsilon Associates, Inc.
3 Clock Tower Place, Suite 250
Maynard, MA 01754

In Association with:
R.G. Vanderweil Engineers, LLP
Acentech Inc.

December 15, 2015

Epsilon
ASSOCIATES INC.

Environmental Notification Form

Commonwealth of Massachusetts

Executive Office of Energy and Environmental Affairs
Massachusetts Environmental Policy Act (MEPA) Office

Environmental Notification Form

For Office Use Only

EEA#: _____

MEPA Analyst: _____

The information requested on this form must be completed in order to submit a document electronically for review under the Massachusetts Environmental Policy Act, 301 CMR 11.00.

Project Name: Central Utilities Plant Second Century Plant Expansion		
Street Address: 59 Vassar Street, Building 42C		
Municipality: Cambridge	Watershed: Charles River	
Universal Transverse Mercator Coordinates: UTM (Zone 19) Easting: 327596 Northing: 4692053	Latitude: 42° 21′ 41.9″ N Longitude: 71° 05′ 36.9″ W	
Estimated commencement date: 2nd Qtr 2016	Estimated completion date: 4th Qtr 2019	
Project Type: Energy	Status of project design: 25 %complete	
Proponent: Massachusetts Institute of Technology		
Street Address: Building NE49, 2nd Floor, 600 Technology Square		
Municipality: Cambridge	State: MA	Zip Code: 02139
Name of Contact Person: Corinne Snowdon		
Firm/Agency: Epsilon Associates, Inc.	Street Address: 3 Clock Tower Place, Suite 250	
Municipality: Maynard	State: MA	Zip Code: 01754
Phone: (978) 897-7100	Fax: (978) 897-0099	E-mail: csnowdon@epsilonassociates.com

Does this project meet or exceed a mandatory EIR threshold (see 301 CMR 11.03)?
☒Yes ☐No

If this is an Expanded Environmental Notification Form (ENF) (see 301 CMR 11.05(7)) or a Notice of Project Change (NPC), are you requesting:

a Single EIR? (see 301 CMR 11.06(8)) ☒Yes ☐No (See Attachment B)
a Special Review Procedure? (see 301CMR 11.09) ☐Yes ☒No
a Waiver of mandatory EIR? (see 301 CMR 11.11) ☐Yes ☒No
a Phase I Waiver? (see 301 CMR 11.11) ☐Yes ☒No
(Note: Greenhouse Gas Emissions analysis must be included in the Expanded ENF.)

Which MEPA review threshold(s) does the project meet or exceed (see 301 CMR 11.03)?
[301 CMR 11.03(7)(b)2.] – Expansion of an existing electric generating facility by 25 or more MW.
[301 CMR 11.03(8)(a)2.] – Modification of an existing Stationary Source with federal potential emissions that collectively will result, after construction and the imposition of required controls, of 75,000 tpy of GHGs based on CO_2 Equivalent.

Which State Agency Permits will the project require? Massachusetts Historical Commission: Determination of No Adverse Effect on Historic Properties; Department of Environmental Protection, Division of Air Quality Control (MassDEP): Major Comprehensive Plan Approval (MCPA); Massachusetts Department of Transportation: Approval for building permit on land on or adjacent to railroad corridor (Chapter 40 §54A)

Identify any financial assistance or land transfer from an Agency of the Commonwealth, including the Agency name and the amount of funding or land area in acres: None

Summary of Project Size & Environmental Impacts	Existing	Change	Total
LAND			
Total site acreage	2.44		
New acres of land altered		0	
Acres of impervious area	2.44	0	2.44
Square feet of new bordering vegetated wetlands alteration		0	
Square feet of new other wetland alteration		0	
Acres of new non-water dependent use of tidelands or waterways		0	
STRUCTURES			
Gross square footage	203,082	80,942	284,024
Number of housing units	0	0	0
Maximum height (feet)	177 (existing stack)	No change (new stack 165 feet)	177 (existing stack)
TRANSPORTATION			
Vehicle trips per day	40	0	40
Parking spaces	103	-103	0
WASTEWATER			
Water Use (Gallons per day)	392,221*	65,650	457,871
Water withdrawal (GPD)	0	0	0
Wastewater generation/treatment (GPD)	54,837*	-3,200	51,637
Length of water mains (miles)	0	0	0
Length of sewer mains (miles)	0	0	0

Has this project been filed with MEPA before?
☐ Yes (EEA #) ☒No

Has any project on this site been filed with MEPA before?
☒ Yes (EEA# 7856) ☐No

*Existing case includes the water use and wastewater generation associated with the installation of new chillers, which is a separate, independent project.

GENERAL PROJECT INFORMATION – all proponents must fill out this section

PROJECT DESCRIPTION:

Describe the existing conditions and land uses on the project site:

The project site includes the Massachusetts Institute of Technology (MIT) Central Utilities Plant (CUP), housed in Building 42 (N16, N16A and 43), and an adjacent surface parking lot with minimal landscaping on the MIT campus in Cambridge, MA. The site is bordered by Albany Street to the north, a parking lot to the west, a parking garage to the east and Vassar Street to the south (see Attachment A-1 and A-2).

The existing MIT CUP consists of a Siemens (ABB) GT10A Combustion Turbine (CT), heat recovery steam generator (HRSG), and electric generator rated at approximately 21 megawatt (MW) and ancillary equipment that started up circa 1995. 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 CUP was 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, U.S. Government Research, classrooms and dormitories. The CUP provides electricity, steam heat, and chilled water to more than 100 MIT buildings. The existing CT provides about 60% of current campus electricity, and the steam from the HRSG is used for heating, and steam driven chillers for cooling, many campus buildings via steam and chiller water distribution systems.

The project site is located on landlocked tidelands. A Public Benefit Determination is included in Attachment C-7. The project site is located more than one-quarter mile from the Charles River and will not impede access and use of the river. In addition, the project will use best available control technology to minimize emissions, while meeting the needs of the MIT campus, a major employer in the area.

Describe the proposed project and its programmatic and physical elements:

MIT's mission is to advance knowledge and educate students in science, technology, and other areas of scholarship that will best serve the nation and the world in the 21st century. MIT's continued leadership in its fields depends on its ability to pursue leading-edge activities, such as nanotechnology research, many of which are energy-intensive.

The existing CT has been in service since its installation in 1995 and will soon reach the end of its service life. The manufacturer will no longer support this equipment under the current form of Long Term Service Agreement due to availability of spare parts and equipment in its maintenance program. Therefore the reliability of this equipment will diminish in future years until spare parts are no longer available. Based on current campus loads and expected growth, it is anticipated that MIT will exceed capacity within the CUP and Eversource feeders to meet the electrical needs of the campus by 2018.

To meet anticipated future electrical needs, MIT is proposing the Central Utilities Plant Second Century Plant Expansion Project, a 44 MW addition to MIT's existing CUP with the intent of meeting the following goals:

- To increase the resiliency of the campus, safeguarding crucial research by enabling MIT to function during a power-loss event;
- To equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and
- To continue conserving energy and reducing MIT's impact on the environment.

The proposed project consists of two nominal 22 MW 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 NOx 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.

Finally, the project will also provide Eversource with a location inside the expanded plant for a regulator station that will supplement and back up the existing station on Third Street and will improve natural gas availability to the area of Cambridge around MIT.

The project is the result of rigorous study and analysis that stretches back more than 10 years. Beginning in 2003, MIT began evaluating a wide range of options that could furnish power to the campus once the existing turbine was ready for replacement. The analysis showed that an expansion of the on-campus cogeneration plant, compared with various methods of procuring electricity and/or steam from off-campus sources, was the most effective and appropriate way to meet the growth of MIT. Given the pending end of the current turbine's service life, the project is necessary to ensure continued service to MIT's existing facilities as well as functionality into the future. Although MIT is proposing additional development in the Kendall Square area which may or may not be serviced by the proposed project, the proposed project is required regardless of these potential developments, and whether or not they are constructed does not impact the need or the future of the proposed project.

By reinvesting in cogeneration and adding capacity as well as new state-of-the-art equipment and technology, MIT will increase its plant energy efficiency by approximately 7% and reduce its greenhouse gas emissions by approximately 5% compared to using conventional energy sources. These energy savings are equivalent to the total annual electricity used in 3,400 single-family homes.

Impacts

The sections below describe the project's anticipated impacts on the environment. The project's impacts are expected to be limited to air quality and noise.

Air Quality

The project will use the Best Available Control Technology (BACT) to minimize air emissions. MassDEP will review the control technologies and predicted impacts as described in the MCPA application in Attachment D to ensure that MassDEP is aware of the environmental consequences associated with permit issuance. MassDEP is precluded from issuing the MCPA until the MEPA review process has concluded. Compliance will be documented through operational controls, stack testing, and continuous emissions monitoring systems.

Through the project, MIT will reduce greenhouse gas emissions by approximately 5% compared with conventional energy sources. Enhancing and expanding the cogeneration plant will also help MIT keep harmful pollutants out of the air, including nitrous oxides (NOx) and sulfur oxides (SOx), two pollutants known to cause respiratory disease and/or impaired lung function. The expanded plant will reduce EPA-regulated emissions of NOx and SOx by almost 80% compared to conventionally produced energy and by 68% compared with the existing single-turbine system. In addition, the existing CT will be replaced by a new, more efficient CHP system that will generate fewer emissions.

Greenhouse Gas Emissions

The greenhouse gas (GHG) analysis in Attachment C-5 documents that the Project will further reduce GHG emissions compared to separate heat and power generation, and that the Project will mitigate GHG impacts to the maximum extent feasible through the selection of efficient generation and support equipment.

Noise

The project will be required to meet the requirements in Title 8, Chapter 8.16, Noise Control of the City of Cambridge Code of Ordinances and MassDEP Noise Criteria, and will be designed to comply with these regulations. Mitigation measures are expected to include air inlet and exhaust mufflers, attenuators on building ventilation systems, reduced-noise fans, and variable frequency drive fans. Planned construction noise mitigation measures include: equipment attenuation devices and noisier construction activities will be scheduled for regular daytime hours. Appendix E of the MCPA application includes a sound level assessment.

Infrastructure

The Project will be installed in an addition to an existing building and be supported by existing infrastructure. The existing electrical utilities will remain as served by Eversource, but there will be some modifications to the entrance to the new addition to the building. The existing natural gas line that services the facility will be relocated during construction of the new addition. The ULSD storage will be increased in the new addition, and a new unloading area will be installed for off road deliveries reducing truck time on the street. Water use is not anticipated to increase, while wastewater generation is anticipated to decrease by approximately 3,200 gpd. In addition, the roof and stormwater from the new addition will be reclaimed to reduce annual water use on campus. The project will incorporate cooling tower water storage use to retain rainwater and not discharge to the City of Cambridge stormwater system.

Historic Resources

There are no historic resources listed on the State or National Registers of Historic Places or included in the Inventory of Historic and Archaeological Assets of the Commonwealth on the Project site; several such sources are located in the vicinity. The Project is unlikely to affect significant historic resources as it is located within a densely development urban area with similarly scaled structures.

Climate Change Resilience

The plant expansion will improve MIT's ability to handle large storm events, such as Superstorm Sandy. The equipment is being designed and sited specifically to maintain operation during severe weather conditions. All of the key equipment in the new cogeneration plant will be built above the anticipated 500-year flood level. The project will also allow for MIT to continue to provide electricity and heating and cooling to most of its buildings even if the electric grid goes down.

Construction

A Construction Management Plan (CMP) will be submitted to the City of Cambridge for approval. This CMP will comply with the City's Construction Management Guidelines and will include general project information as well as details related to work hours, delivery and truck routes, worker access and parking plans, police details, truck unloading and staging, construction site signs, on-street parking occupancy, pedestrian access, sidewalk obstruction, modes of transportation for construction workers, and initiatives for reducing driving and parking demands.

The CMP will demonstrate the intent to maintain public safety throughout the construction period through barricades, defined temporary walkways, signage, and other protective measures. The Proponent does not anticipate the need to close roads. If it becomes necessary to temporarily close sidewalks, then appropriate signage and fencing will ensure safe pedestrian passage. The CMP will also highlight the protection of utilities and the control of noise and dust.

Describe the on-site project alternatives (and alternative off-site locations, if applicable), considered by the proponent, including at least one feasible alternative that is allowed under current zoning, and the reasons(s) that they were not selected as the preferred alternative:

As mentioned above, the existing CT is nearing the end of its service life. To continue to meet the expected electric and steam needs of its campus, MIT examined five options to replace the existing CT, as discussed below.

Option 1 (No Build option) - Retire existing CT and purchase all electricity from utility
The elimination of the generating capacity exposes the campus to outages of the grid without local back up.
Option 2 - Rebuilding existing CT with spare parts
This option would require MIT to continue to rely on older, less efficient equipment, and would not provide the environmental benefits of a new turbine package. This option would also be anticipated to be susceptible to flooding in the future.

Option 3 - Replace Existing CT with new turbine package in the location of the existing CT
This option would be anticipated to be susceptible to flooding in the future. In addition, MIT would have an increased dependence on the grid, which would create more emissions, for its future electrical needs than with the proposed project.

Option 4 - Expand existing capacity with new, approximately 30 MW turbine
The installation of a single new combustion turbine does not provide the reliability that a redundant system offers. In addition, MIT would have an increased dependence on the grid, which would create more emissions, for its future electrical needs than with the proposed project.

Option 5 (Proposed Project) - Expand existing capacity with two new turbines
This option is the proposed project, which allows for redundancy to minimize dependence on the utility grid, will be protected against flooding, and offers the lowest life cycle cost. In addition, the more energy creating by the cogeneration plant, the fewer air emissions due to a decreased need to rely on less efficient energy methods (e.g., the electric grid, stand-alone boilers).

Summarize the mitigation measures proposed to offset the impacts of the preferred alternative:

Proposed mitigation measures include: the use of CHP to maximize the Project's energy efficiency; the use of existing infrastructure; the selection of efficient equipment; placement adjacent to an existing facility on an underused lot; the use of the cleanest available fuels; advanced combustion design; air pollution control catalysts; the placement of generation equipment inside a building designed for noise mitigation; and the use of silencers and barrier walls to mitigate noise from roof-mounted equipment.

In addition to the air quality and noise benefits, MIT has partnered with Eversource to make the dedicated high-pressure gas line available to Eversource through a regulating station inside the new plant. This new regulating station will supplement and back up the existing station on Third Street and will improve natural gas availability to the area of Cambridge around MIT. The construction of the project will also result in electric capacity being available for continued growth and development in the area.

If the project is proposed to be constructed in phases, please describe each phase:

The first CT is planned to be in operation in 2018, and the second CT is planned to be in operation in 2019, at which time the existing CT will be retired.

AREAS OF CRITICAL ENVIRONMENTAL CONCERN:
Is the project within or adjacent to an Area of Critical Environmental Concern?
☐Yes (Specify_____) ☒No if yes, does the ACEC have an approved Resource Management Plan? ___ Yes____No; If yes, describe how the project complies with this plan. _____
Will there be stormwater runoff or discharge to the designated ACEC? ___ Yes __X__ No; If yes, describe and assess the potential impacts of such stormwater runoff/discharge to the designated ACEC. _____

RARE SPECIES:
Does the project site include Estimated and/or Priority Habitat of State-Listed Rare Species? (see http://www.mass.gov/dfwele/dfw/nhesp/regulatory_review/priority_habitat/priority_habitat_home.htm)
☐Yes (Specify_____) ☒No

HISTORICAL /ARCHAEOLOGICAL RESOURCES:
Does the project site include any structure, site or district listed in the State Register of Historic Place or the inventory of Historic and Archaeological Assets of the Commonwealth?
☐Yes (Specify_____) ☒No
If yes, does the project involve any demolition or destruction of any listed or inventoried historic or archaeological resources? ☐Yes (Specify_____) ☐ No

WATER RESOURCES:
Is there an Outstanding Resource Water (ORW) on or within a half-mile radius of the project site? ___ Yes __X__ No; if yes, identify the ORW and its location.

Are there any impaired water bodies on or within a half-mile radius of the project site? __X__ Yes ___ No; if yes, identify the water body and pollutant(s) causing the impairment:

Charles River - causes of impairment include: salinity, sediment screening value (exceedence), chlorophyll-a, combined biota/habitat bioassessments, DDT, dissolved oxygen saturation, Escherichia coli, excess algal growth, nutrient/eutrophication biological, Indicators, oil and grease, oxygen (dissolved), PCB in fish tissue, phosphorus (total), secchi disk transparency, taste and odor, and water temperature.

Is the project within a medium or high stress basin, as established by the Massachusetts Water Resources Commission? ___Yes __X__ No

STORMWATER MANAGEMENT:

Generally describe the project's stormwater impacts and measures that the project will take to comply with the standards found in MassDEP's Stormwater Management Regulations:

The roof and stormwater from the new addition will be reclaimed to reduce annual water use on campus. The project will incorporate cooling tower water storage use to retain rainwater and not discharge to the City of Cambridge stormwater system.

Stormwater design will follow MassDEP Stormwater Management Standards to the maximum extent practical, which will generally improve stormwater management from the existing conditions (surface parking lot). This design will include: avoiding discharge of untreated stormwater directly to wetlands or waterways; designing systems so that post-development peak discharge rates do not exceed pre-development peak discharge rates; minimizing loss of annual recharge to groundwater; removing 80% of the average annual post-construction load of Total Suspended Solids (TSS); reducing potential pollutant loads by housing equipment indoors; developing a plan to control construction-related impacts; implementing a long-term operation and maintenance plan; and prohibiting all illicit discharges.

MASSACHUSETTS CONTINGENCY PLAN:

Has the project site been, or is it currently being, regulated under M.G.L.c.21E or the Massachusetts Contingency Plan? Yes _X_ No ___ ; if yes, please describe the current status of the site (including Release Tracking Number (RTN), cleanup phase, and Response Action Outcome classification): RTN 3-0010471, Closed with AUL, RAO Class A3; RTN 3-0028407, Open, URAM; RTN 3-0028424, Closed, RAO Class A3; RTN 3-0011358, Closed, RAO Class A2; RTN 3-0018830, Closed, RAO Class A2; RTN 3-0026482, Closed, RAO Class A2; RTN 3-0028301, Closed, RAO Class A1; RTN 3-0021265, Closed, RAO Class A1

Is there an Activity and Use Limitation (AUL) on any portion of the project site?
Yes _X_ No ___ if yes, describe which portion of the site and how the project will be consistent with the AUL: The AUL is for the parking lot portion of the site and states that activities and uses inconsistent with the AUL include: excavation, construction, dewatering, spreading, stockpiling and/or other disturbance of subsurface strata below grade for any reason, including without limitation, maintenance, repair and/or construction of existing or new structures except as performed in accordance with applicable regulations and a health and safety plan approved by an LSP. Any of the listed activities will be completed in accordance with applicable regulations and a health and safety plan will be developed by the Proponent.

Are you aware of any Reportable Conditions at the property that have not yet been assigned an RTN? Yes ___ No _X_ ; if yes, please describe:_____

SOLID AND HAZARDOUS WASTE:

If the project will generate solid waste during demolition or construction, describe alternatives considered for re-use, recycling, and disposal of, e.g., asphalt, brick, concrete, gypsum, metal, wood: The project will divert construction waste from local landfills by recycling waste material generated on the project site as feasible. The disposal contract between the developer and construction manager will include specific requirements to ensure that construction procedures require the necessary segregation, reprocessing, reuse, and recycling of materials when possible. For the materials that cannot be recycled, solid waste will be transported in covered trucks to an approved solid waste facility per MassDEP Regulations for Solid Waste Facilities, 310 CMR 16.00.

The existing gas turbine will likely be sold to a used equipment company as spare parts for other turbines still in service. The Heat Recovery Steam Generator (HRSG) will be tested for any hazardous materials and, once confirmed to be free of any such materials, will be cut up for scrap and removed to be recycled. MIT's goal is to recycle as much of the removed materials as possible throughout the project. It is MIT's policy to confirm that all regulated or hazardous materials are identified and properly handled over the course of a project such as this.

Will your project disturb asbestos containing materials? Yes ___ No _X_; if yes, please consult state asbestos requirements at http://mass.gov/MassDEP/air/asbhom01.htm

Describe anti-idling and other measures to limit emissions from construction equipment:
The construction contract will require contractors to use a number of measures to reduce potential emissions and minimize impacts from construction vehicles, including:

- Use wetting agents where needed on a scheduled basis;
- Use covered trucks;
- Minimize exposed storage of debris on-site;
- Monitor construction practices to minimize unnecessary transfers and mechanical disturbances of loose materials;
- Store aggregate materials away from the areas of greatest pedestrian activity, where and when possible;
- Establish a tire cleaning area at the exit gate to prevent dirt from reaching the street;
- Clean streets and sidewalks regularly to minimize dust accumulations;
- Use appropriate mufflers on equipment, and properly maintain intake and exhaust mufflers;
- Use muffling enclosures on continuously-operating equipment (e.g., air compressors and welding generators);
- Use the most quiet construction operations, techniques, and equipment, where feasible;
- Schedule equipment operations to keep average noise levels low, synchronize noisiest operations with times of highest ambient noise levels, and maintain relatively uniform noise levels;
- Turn off idling equipment; and
- Use shielding or distance to separate noisy equipment from sensitive receptors.

DESIGNATED WILD AND SCENIC RIVER:

Is this project site located wholly or partially within a defined river corridor of a federally designated Wild and Scenic River or a state designated Scenic River? Yes ___ No _X_ ; if yes, specify name of river and designation:
If yes, does the project have the potential to impact any of the "outstandingly remarkable" resources of a federally Wild and Scenic River or the stated purpose of a state designated Scenic River? Yes ___ No ___ ; if yes, specify name of river and designation: _____; if yes, will the project will result in any impacts to any of the designated "outstandingly remarkable" resources of the Wild and Scenic River or the stated purposes of a Scenic River. Yes ___ No ___ ; if yes,describe the potential impacts to one or more of the "outstandingly remarkable" resources or stated purposes and mitigation measures proposed.

ATTACHMENTS:

1. List of all attachments to this document. Attachment A-1
2. U.S.G.S. map (good quality color copy, 8-½ x 11 inches or larger, at a scale of 1:24,000) indicating the project location and boundaries. Attachment A-2
3.. Plan, at an appropriate scale, of existing conditions on the project site and its immediate environs, showing all known structures, roadways and parking lots, railroad rights-of-way, wetlands and water bodies, wooded areas, farmland, steep slopes, public open spaces, and major utilities. Attachment A-3
4 Plan, at an appropriate scale, depicting environmental constraints on or adjacent to the project site such as Priority and/or Estimated Habitat of state-listed rare species, Areas of Critical Environmental Concern, Chapter 91 jurisdictional areas, Article 97 lands, wetland resource area delineations, water supply protection areas, and historic resources and/or districts. Attachment A-4
5. Plan, at an appropriate scale, of proposed conditions upon completion of project (if construction of the project is proposed to be phased, there should be a site plan showing conditions upon the completion of each phase). Attachment A-5
6. List of all agencies and persons to whom the proponent circulated the ENF, in accordance with 301 CMR 11.16(2). Attachment A-6
7. List of municipal and federal permits and reviews required by the project, as applicable. Federal Prevention of Significant Deterioration (PSD) air permit, administered by MassDEP.

Additional Attachments

Attachment B Request for Single EIR
Attachment C Expanded Narrative
Attachment D MCPA Application (electronic copy)

LAND SECTION – all proponents must fill out this section

I. Thresholds / Permits

A. Does the project meet or exceed any review thresholds related to **land** (see 301 CMR 11.03(1)
___ Yes _X_ No; if yes, specify each threshold:

II. Impacts and Permits

A. Describe, in acres, the current and proposed character of the project site, as follows:

	Existing	Change	Total
Footprint of buildings	1.50	0.60	2.10
Internal roadways	0	0	0
Parking and other paved areas	0.87	-0.55	0.32
Other altered areas	0.07	-0.05	0.02
Undeveloped areas	0	0	0
Total: Project Site Acreage	2.44	0	2.44

B. Has any part of the project site been in active agricultural use in the last five years?
___ Yes _X_ No; if yes, how many acres of land in agricultural use (with prime state or locally important agricultural soils) will be converted to nonagricultural use?

C. Is any part of the project site currently or proposed to be in active forestry use?
___ Yes _X_ No; if yes, please describe current and proposed forestry activities and indicate whether any part of the site is the subject of a forest management plan approved by the Department of Conservation and Recreation:

D. Does any part of the project involve conversion of land held for natural resources purposes in accordance with Article 97 of the Amendments to the Constitution of the Commonwealth to any purpose not in accordance with Article 97? ___ Yes _X_ No; if yes, describe:

E. Is any part of the project site currently subject to a conservation restriction, preservation restriction, agricultural preservation restriction or watershed preservation restriction? ___ Yes _X_ No; if yes, does the project involve the release or modification of such restriction? ___ Yes ___ No; if yes, describe:

F. Does the project require approval of a new urban redevelopment project or a fundamental change in an existing urban redevelopment project under M.G.L.c.121A? ___ Yes _X_ No; if yes, describe:

G. Does the project require approval of a new urban renewal plan or a major modification of an existing urban renewal plan under M.G.L.c.121B? Yes ___ No _X_ ; if yes, describe:

III. Consistency

A. Identify the current municipal comprehensive land use plan:
Title: Toward A Sustainable Future: Cambridge Growth Policy Date: Updated 2007
We note that the Growth Policy is not a master plan and does not identify land uses. However, the project is allowed under current zoning for the site.

B. Describe the project's consistency with that plan with regard to:

a. Economic development: The Growth Policy seeks to create a thriving economic base, which includes a thriving educational industry, and allow for institutions to continue to be competitive. The project will allow MIT to continue its growth and stay competitive with other research institutions around the world by providing a reliable source of energy.

b. Adequacy of infrastructure: The Growth Policy focuses on transportation infrastructure, which will not be impacted by the project. Utility infrastructure exists in the area to support the project. For local utilities such as Eversource, the project will reduce MIT's day-to-day demand, freeing up capacity for the surrounding community. MIT's improved self-sufficiency will also reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource with a location inside the new addition to the plant for a regulator station that gives Eversource access to high-pressure gas on campus. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands, without digging up city streets and replacing pipes.

c. Open space impacts: The project will not impact open spaces as the site is currently used as a surface parking lot or is developed, and no public open spaces are in the immediate vicinity of the site.

d. Compatibility with adjacent land uses: The project site include the existing MIT CUP to which an addition will be built, and is located on the MIT campus within The Massachusetts Institute of Technology Overlay District.

C. Identify the current Regional Policy Plan of the applicable Regional Planning Agency (RPA)

RPA: Metropolitan Area Planning Council

Title: MetroFuture Date: 2009

D. Describe the project's consistency with that plan with regard to:

1) economic development: The project will allow MIT to continue to provide reliable, efficient energy to its campus in support of its activities that create economic benefits for its students, employees, and the city and state.

2) adequacy of infrastructure: Infrastructure exists in the area to support the project. For local utilities such as Eversource, the project will reduce MIT's day-to-day demand, freeing up capacity for the surrounding community. MIT's improved self-sufficiency will also reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource with a location inside the new addition to the plant for a regulator station that gives Eversource access to high-pressure gas on campus. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands, without digging up city streets and replacing pipes. The project will allow and host new Eversource equipment to provide the City of Cambridge back up gas supply to the existing natural gas users.

3) open space impacts: The existing Project site does not include any public open space, and the Project will not impact nearby open spaces.

RARE SPECIES SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **rare species or habitat** (see 301 CMR 11.03(2))? ___ Yes **_X_** No; if yes, specify, in quantitative terms:

(NOTE: If you are uncertain, it is recommended that you consult with the Natural Heritage and Endangered Species Program (NHESP) prior to submitting the ENF.)

B. Does the project require any state permits related to **rare species or habitat**? ___ Yes **_X_** No

C. Does the project site fall within mapped rare species habitat (Priority or Estimated Habitat?) in the current Massachusetts Natural Heritage Atlas (attach relevant page)? ___ Yes **_X_** No.

D. If you answered "No" to all questions A, B and C, proceed to the **Wetlands, Waterways, and Tidelands Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Rare Species section below.

II. Impacts and Permits

A. Does the project site fall within Priority or Estimated Habitat in the current Massachusetts Natural Heritage Atlas (attach relevant page)? ___ Yes ___ No. If yes,

1. Have you consulted with the Division of Fisheries and Wildlife Natural Heritage and Endangered Species Program (NHESP)? ___Yes ___No; if yes, have you received a determination as to whether the project will result in the "take" of a rare species? ___ Yes ___ No; if yes, attach the letter of determination to this submission.

2. Will the project "take" an endangered, threatened, and/or species of special concern in accordance with M.G.L. c.131A (see also 321 CMR 10.04)? ___ Yes ___ No; if yes, provide a summary of proposed measures to minimize and mitigate rare species impacts

3. Which rare species are known to occur within the Priority or Estimated Habitat?

4. Has the site been surveyed for rare species in accordance with the Massachusetts Endangered Species Act? ___ Yes ___ No

4. If your project is within Estimated Habitat, have you filed a Notice of Intent or received an Order of Conditions for this project? ___ Yes ___ No; if yes, did you send a copy of the Notice of Intent to the Natural Heritage and Endangered Species Program, in accordance with the Wetlands Protection Act regulations? ___ Yes ___ No

B. Will the project "take" an endangered, threatened, and/or species of special concern in accordance with M.G.L. c.131A (see also 321 CMR 10.04)? ___ Yes ___ No; if yes, provide a summary of proposed measures to minimize and mitigate impacts to significant habitat:

WETLANDS, WATERWAYS, AND TIDELANDS SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **wetlands, waterways, and tidelands** (see 301 CMR 11.03(3))? ___ Yes _X_ No; if yes, specify, in quantitative terms:

B. Does the project require any state permits (or a local Order of Conditions) related to **wetlands, waterways, or tidelands**? ___ Yes _X_ No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Water Supply Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Wetlands, Waterways, and Tidelands Section below.

II. Wetlands Impacts and Permits

A. Does the project require a new or amended Order of Conditions under the Wetlands Protection Act (M.G.L. c.131A)? ___ Yes ___ No; if yes, has a Notice of Intent been filed? ___ Yes ___ No; if yes, list the date and MassDEP file number: _____; if yes, has a local Order of Conditions been issued? ___ Yes ___ No; Was the Order of Conditions appealed? ___ Yes ___ No. Will the project require a Variance from the Wetlands regulations? ___ Yes ___ No.

B. Describe any proposed permanent or temporary impacts to wetland resource areas located on the project site:

C. Estimate the extent and type of impact that the project will have on wetland resources, and indicate whether the impacts are temporary or permanent:

Coastal Wetlands	Area (square feet) or Length (linear feet)	Temporary or Permanent Impact?
Land Under the Ocean	_____	_____
Designated Port Areas	_____	_____
Coastal Beaches	_____	_____
Coastal Dunes	_____	_____
Barrier Beaches	_____	_____
Coastal Banks	_____	_____
Rocky Intertidal Shores	_____	_____
Salt Marshes	_____	_____
Land Under Salt Ponds	_____	_____
Land Containing Shellfish	_____	_____
Fish Runs	_____	_____
Land Subject to Coastal Storm Flowage	_____	_____
Inland Wetlands		
Bank (lf)	_____	_____
Bordering Vegetated Wetlands	_____	_____
Isolated Vegetated Wetlands	_____	_____
Land under Water	_____	_____
Isolated Land Subject to Flooding	_____	_____
Borderi ng Land Subject to Flooding	_____	_____
Riverfront Area	_____	_____

D. Is any part of the project:

1. proposed as a **limited project**? ___ Yes ___ No; if yes, what is the area (in sf)?____
2. the construction or alteration of a **dam**? ___ Yes ___ No; if yes, describe:
3. fill or structure in a **velocity zone** or **regulatory floodway**? ___ Yes ___ No
4. dredging or disposal of dredged material? ___ Yes ___ No; if yes, describe the volume of dredged material and the proposed disposal site:

5. a discharge to an **Outstanding Resource Water (ORW)** or an **Area of Critical Environmental Concern (ACEC)**? ___ Yes ___ No
6. subject to a wetlands restriction order? ___ Yes ___ No; if yes, identify the area (in sf):
7. located in buffer zones? ___Yes ___No; if yes, how much (in sf) _____

E. Will the project:
1. be subject to a local wetlands ordinance or bylaw? ___ Yes ___ No
2. alter any federally-protected wetlands not regulated under state law? ___ Yes ___ No; if yes, what is the area (sf)?

III. Waterways and Tidelands Impacts and Permits

A. Does the project site contain waterways or tidelands (including filled former tidelands) that are subject to the Waterways Act, M.G.L.c.91? ___ Yes ___ No; if yes, is there a current Chapter 91 License or Permit affecting the project site? ___ Yes ___ No; if yes, list the date and license or permit number and provide a copy of the historic map used to determine extent of filled tidelands:

B. Does the project require a new or modified license or permit under M.G.L.c.91? ___ Yes ___ No; if yes, how many acres of the project site subject to M.G.L.c.91 will be for non-water-dependent use? Current ___ Change ___ Total ___

If yes, how many square feet of solid fill or pile-supported structures (in sf)?

C. For non-water-dependent use projects, indicate the following:

Area of filled tidelands on the site:_____

Area of filled tidelands covered by buildings:_____

For portions of site on filled tidelands, list ground floor uses and area of each use: _____

Does the project include new non-water-dependent uses located over flowed tidelands? Yes ___ No ___

Height of building on filled tidelands_____

Also show the following on a site plan: Mean High Water, Mean Low Water, Water-dependent Use Zone, location of uses within buildings on tidelands, and interior and exterior areas and facilities dedicated for public use, and historic high and historic low water marks.

D. Is the project located on landlocked tidelands? ___ Yes ___ No; if yes, describe the project's impact on the public's right to access, use and enjoy jurisdictional tidelands and describe measures the project will implement to avoid, minimize or mitigate any adverse impact:

E. Is the project located in an area where low groundwater levels have been identified by a municipality or by a state or federal agency as a threat to building foundations? ___Yes ___ No; if yes, describe the project's impact on groundwater levels and describe measures the project will implement to avoid, minimize or mitigate any adverse impact:

F. Is the project non-water-dependent **and** located on landlocked tidelands **or** waterways or tidelands subject to the Waterways Act **and** subject to a mandatory EIR? ___ Yes ___ No;

(NOTE: If yes, then the project will be subject to Public Benefit Review and Determination.)

G. Does the project include dredging? ___ Yes ___ No; if yes, answer the following questions:

What type of dredging? Improvement ___ Maintenance ___ Both ____

What is the proposed dredge volume, in cubic yards (cys) _____

What is the proposed dredge footprint ____length (ft) ___width (ft)____depth (ft);

Will dredging impact the following resource areas?

Intertidal Yes__ No__; if yes, ___ sq ft

Outstanding Resource Waters Yes__ No__; if yes, ___ sq ft

Other resource area (i.e. shellfish beds, eel grass beds) Yes__ No__; if yes __ sq ft

If yes to any of the above, have you evaluated appropriate and practicable steps to: 1) avoidance; 2) if avoidance is not possible, minimization; 3) if either avoidance or minimize is not possible, mitigation?

If no to any of the above, what information or documentation was used to support this determination?

Provide a comprehensive analysis of practicable alternatives for improvement dredging in accordance with 314 CMR 9.07(1)(b). Physical and chemical data of the sediment shall be included in the comprehensive analysis.

Sediment Characterization

Existing gradation analysis results? __Yes ___No: if yes, provide results.

Existing chemical results for parameters listed in 314 CMR 9.07(2)(b)6? ___Yes ____No; if yes, provide results.

Do you have sufficient information to evaluate feasibility of the following management options for dredged sediment? If yes, check the appropriate option.

Beach Nourishment ___

Unconfined Ocean Disposal ___

Confined Disposal:

Confined Aquatic Disposal (CAD) ___

Confined Disposal Facility (CDF) ___

Landfill Reuse in accordance with COMM-97-001 ___

Shoreline Placement ___

Upland Material Reuse____

In-State landfill disposal____

Out-of-state landfill disposal ____

(NOTE: This information is required for a 401 Water Quality Certification.)

IV. Consistency:

A. Does the project have effects on the coastal resources or uses, and/or is the project located within the Coastal Zone? ___ Yes ___ No; if yes, describe these effects and the projects consistency with the policies of the Office of Coastal Zone Management:

B. Is the project located within an area subject to a Municipal Harbor Plan? ___ Yes ___ No; if yes, identify the Municipal Harbor Plan and describe the project's consistency with that plan:

WATER SUPPLY SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **water supply** (see 301 CMR 11.03(4))? ___ Yes **_X_** No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **water supply**? ___ Yes **_X_** No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Wastewater Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Water Supply Section below.

II. Impacts and Permits

A. Describe, in gallons per day (gpd), the volume and source of water use for existing and proposed activities at the project site:

	Existing	Change	Total
Municipal or regional water supply	_____	_____	_____
Withdrawal from groundwater	_____	_____	_____
Withdrawal from surface water	_____	_____	_____
Interbasin transfer	_____	_____	_____

(NOTE: Interbasin Transfer approval will be required if the basin and community where the proposed water supply source is located is different from the basin and community where the wastewater from the source will be discharged.)

B. If the source is a municipal or regional supply, has the municipality or region indicated that there is adequate capacity in the system to accommodate the project? ___ Yes ___ No

C. If the project involves a new or expanded withdrawal from a groundwater or surface water source, has a pumping test been conducted? ___ Yes ___ No; if yes, attach a map of the drilling sites and a summary of the alternatives considered and the results. _____

D. What is the currently permitted withdrawal at the proposed water supply source (in gallons per day)? _____Will the project require an increase in that withdrawal? ___Yes ___No; if yes, then how much of an increase (gpd)? _____

E. Does the project site currently contain a water supply well, a drinking water treatment facility, water main, or other water supply facility, or will the project involve construction of a new facility? ___ Yes ___No. If yes, describe existing and proposed water supply facilities at the project site:

	Permitted Flow	Existing Avg Daily Flow	Project Flow	Total
Capacity of water supply well(s) (gpd)	_____	_____	_____	_____
Capacity of water treatment plant (gpd)	_____	_____	_____	_____

F. If the project involves a new interbasin transfer of water, which basins are involved, what is the direction of the transfer, and is the interbasin transfer existing or proposed?

G. Does the project involve:

1. new water service by the Massachusetts Water Resources Authority or other agency of the Commonwealth to a municipality or water district? ___ Yes ___ No
2. a Watershed Protection Act variance? ___ Yes ___ No; if yes, how many acres of alteration?
3. a non-bridged stream crossing 1,000 or less feet upstream of a public surface drinking water supply for purpose of forest harvesting activities? ___ Yes ___ No

III. Consistency

Describe the project's consistency with water conservation plans or other plans to enhance water resources, quality, facilities and services:

WASTEWATER SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **wastewater** (see 301 CMR 11.03(5))? __ Yes **_X_** No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **wastewater**? _____ Yes **_X_** No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Transportation -- Traffic Generation Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Wastewater Section below.

II. Impacts and Permits

A. Describe the volume (in gallons per day) and type of disposal of wastewater generation for existing and proposed activities at the project site (calculate according to 310 CMR 15.00 for septic systems or 314 CMR 7.00 for sewer systems):

	Existing	Change	Total
Discharge of sanitary wastewater			
Discharge of industrial wastewater			
TOTAL			

	Existing	Change	Total
Discharge to groundwater			
Discharge to outstanding resource water			
Discharge to surface water			
Discharge to municipal or regional wastewat facility			
TOTAL			

B. Is the existing collection system at or near its capacity? ___ Yes ____ No; if yes, then describe the measures to be undertaken to accommodate the project's wastewater flows:

C. Is the existing wastewater disposal facility at or near its permitted capacity? ___ Yes ____ No; if yes, then describe the measures to be undertaken to accommodate the project's wastewater flows:

D. Does the project site currently contain a wastewater treatment facility, sewer main, or other wastewater disposal facility, or will the project involve construction of a new facility? ___ Yes ___ No; if yes, describe as follows:

	Permitted	Existing Avg Daily Flow	Project Flow	Total
Wastewater treatment plant capacity (in gallons per day)	_____	_____	_____	_____

E. If the project requires an interbasin transfer of wastewater, which basins are involved, what is the direction of the transfer, and is the interbasin transfer existing or new?

F. Does the project involve new sewer service by the Massachusetts Water Resources Authority (MWRA) or other Agency of the Commonwealth to a municipality or sewer district? ___ Yes ___ No

G. Is there an existing facility, or is a new facility proposed at the project site for the storage, treatment, processing, combustion or disposal of sewage sludge, sludge ash, grit, screenings, wastewater reuse (gray water) or other sewage residual materials? ___ Yes ___ No; if yes, what is the capacity (tons per day):

	Existing	Change	Total
Storage	_____	_____	_____
Treatment	_____	_____	_____
Processing	_____	_____	_____
Combustion	_____	_____	_____
Disposal	_____	_____	_____

H. Describe the water conservation measures to be undertaken by the project, and other wastewater mitigation, such as infiltration and inflow removal.

III. Consistency

A. Describe measures that the proponent will take to comply with applicable state, regional, and local plans and policies related to wastewater management:

B. If the project requires a sewer extension permit, is that extension included in a comprehensive wastewater management plan? ___ Yes ____ No; if yes, indicate the EEA number for the plan and whether the project site is within a sewer service area recommended or approved in that plan:

TRANSPORTATION SECTION (TRAFFIC GENERATION)

I. Thresholds / Permit

A. Will the project meet or exceed any review thresholds related to **traffic generation** (see 301 CMR 11.03(6))? _____ Yes ___**X**___ No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **state-controlled roadways**? _____ Yes _**X**_ No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Roadways and Other Transportation Facilities Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Traffic Generation Section below.

II. Traffic Impacts and Permits

A. Describe existing and proposed vehicular traffic generated by activities at the project site:

	Existing	Change	Total
Number of parking spaces			
Number of ITE vehicle trips per day			

ITE land Use Code(s):

B. What is the estimated average daily traffic on roadways serving the site?

Roadway	Existing	Change	Total

C. If applicable, describe proposed mitigation measures on state-controlled roadways that the project proponent will implement:

D. How will the project implement and/or promote the use of transit, pedestrian and bicycle facilities and services to provide access to and from the project site?

E. Is there a Transportation Management Association (TMA) that provides transportation demand management (TDM) services in the area of the project site? ___ Yes ____ No; if yes, describe if and how will the project will participate in the TMA:

F. Will the project use (or occur in the immediate vicinity of) water, rail, or air transportation facilities? ___ Yes ____ No; if yes, generally describe:

G. If the project will penetrate approach airspace of a nearby airport, has the proponent filed a Massachusetts Aeronautics Commission Airspace Review Form (780 CMR 111.7) and a Notice of Proposed Construction or Alteration with the Federal Aviation Administration (FAA) (CFR Title 14 Part 77.13, forms 7460-1 and 7460-2)?

III. Consistency

Describe measures that the proponent will take to comply with municipal, regional, state, and federal plans and policies related to traffic, transit, pedestrian and bicycle transportation facilities and services:

TRANSPORTATION SECTION (ROADWAYS AND OTHER TRANSPORTATION FACILITIES)

I. Thresholds

A. Will the project meet or exceed any review thresholds related to **roadways or other transportation facilities** (see 301 CMR 11.03(6))? ___ Yes _X_ No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **roadways or other transportation facilities**? ___ Yes _X_ No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Energy Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Roadways Section below.

II. Transportation Facility Impacts

A. Describe existing and proposed transportation facilities in the immediate vicinity of the project site:

B. Will the project involve any

1. Alteration of bank or terrain (in linear feet)? _____
2. Cutting of living public shade trees (number)? _____
3. Elimination of stone wall (in linear feet)? _____

III. Consistency -- Describe the project's consistency with other federal, state, regional, and local plans and policies related to traffic, transit, pedestrian and bicycle transportation facilities and services, including consistency with the applicable regional transportation plan and the Transportation Improvements Plan (TIP), the State Bicycle Plan, and the State Pedestrian Plan:

ENERGY SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **energy** (see 301 CMR 11.03(7))?
_X_ Yes ___ No; if yes, specify, in quantitative terms:
[301 CMR 11.03(7)(b)2.] – Expansion of an existing electric generating facility by 25 or more MW. On a net, nominal basis, the proposed expansion is 23 MW, but there are conditions under which the expansion of total capacity could exceed 25 MW.

B. Does the project require any state permits related to **energy**? ____ Yes _X_ No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Air Quality Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Energy Section below.

II. Impacts and Permits

A. Describe existing and proposed energy generation and transmission facilities at the project site:

	Existing	Change	Total
Capacity of electric generating facility (megawatts)	21	23	44
Length of fuel line (in miles)	0	0	0
Length of transmission lines (in miles)	0	0	0
Capacity of transmission lines (in kilovolts)	n/a	n/a	n/a

B. If the project involves construction or expansion of an electric generating facility, what are:

1. the facility's current and proposed fuel source(s)? Natural Gas, Backup ultra low sulfur diesel (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.
2. the facility's current and proposed cooling source(s)? Cooling towers

C. If the project involves construction of an electrical transmission line, will it be located on a new, unused, or abandoned right of way? ___Yes ___No; if yes, please describe:

D. Describe the project's other impacts on energy facilities and services:

The project will result in greater reliability and more capacity to serve the MIT campus. For local utilities such as Eversource, the project will reduce MIT's day-to-day demand, freeing up capacity for the surrounding community. MIT's improved self-sufficiency will also reduce the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource with a location inside the new addition to the plant for a regulator station that gives Eversource access to high-pressure gas on campus. With this access, Eversource can continue providing service to this area of Cambridge even as it develops and expands, without digging up city streets and replacing pipes.

III. Consistency

Describe the project's consistency with state, municipal, regional, and federal plans and policies for enhancing energy facilities and services:

The project is consistent with federal, state, and Cambridge plans to improve energy efficiency by encouraging combined heat and power or cogeneration, as well as policies to improve system reliability through microgrids. Specifically, the project expects to qualify for incentives through the MassSave energy efficiency incentives (administered through the local electric utility) and alternative energy portfolio standard (APS) credits (administered through the Department Of Energy Resources). Encouraging cogeneration is a listed goal of the Cambridge Getting to Net Zero Task Force.

AIR QUALITY SECTION

I. Thresholds

A. Will the project meet or exceed any review thresholds related to **air quality** (see 301 CMR 11.03(8))? **_X_** Yes ___ No; if yes, specify, in quantitative terms:

[301 CMR 11.03(8)(a)2.] – Modification of an existing Stationary Source with federal potential emissions that collectively will result, after construction and the imposition of required controls, of 75,000 tpy of GHGs based on CO_2 Equivalent.

B. Does the project require any state permits related to **air quality**? **_X_** Yes ___ No; if yes, specify which permit: MassDEP – Major Comprehensive Plan Approval

C. If you answered "No" to both questions A and B, proceed to the **Solid and Hazardous Waste Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Air Quality Section below.

II. Impacts and Permits

A. Does the project involve construction or modification of a major stationary source (see 310 CMR 7.00, Appendix A)? **_X_** Yes ___ No; if yes, describe existing and proposed emissions (in tons per day) of:

	Existing	Change	Total
Particulate matter	0.09	0.17	0.26
Carbon monoxide	0.10	0.061	0.16
Sulfur dioxide	0.40	0.024	0.42
Volatile organic compounds	0.06	0.11	0.17
Oxides of nitrogen	0.55	0.088	0.64
Lead	<0.01	<0.01	<0.01
Any hazardous air pollutant	0.02	<0.01	0.03
Carbon dioxide	949	1099	2048

B. Describe the project's other impacts on air resources and air quality, including noise impacts:

Impacts to air resources will be minimized through the use of BACT as documented in the MCPA application in Attachment D. The generation of air emissions will be minimized through the use of CHP, cleanest available fuels, efficient power and heat generation equipment, and advanced combustion controls. Air emissions that do occur will be mitigated by post-combustion controls: a selective catalytic reduction system and an oxidation catalyst. The treated exhaust will exit through an approximately 165-foot stack.

The MCPA application in Attachment D documents that the Project's impacts to air quality will not cause or contribute to violations of any ambient air quality standards. Specifically, air quality dispersion modeling has been used to predict ambient air impacts from the Project, taking into account worst-case emission rates, nearby structures and sources, five years of weather data, and other Project- and location-specific parameters. The model results show impacts below national and Massachusetts standards for all pollutants and averaging times.

Noise level increases from the Project modeled noise-sensitive receptors, taking into account attenuation due to distance, structures, and noise control measures, are predicted to remain below 10 dBA during even the quietest nighttime hours, and will comply with all MassDEP A-weighted and "pure tone" noise limits. A sound level assessment is included in the MCPA in Attachment D.

III. Consistency

A. Describe the project's consistency with the State Implementation Plan:

The SIP is a plan for each State which identifies how that State will attain and/or maintain the National Ambient Air Quality Standards (NAAQS). The project will be consistent with the State Implementation Plan (SIP), and the planning documents that support it. The project will comply with the state regulations that USEPA has approved for meeting clean air standards and associated Clean Air Act requirements, notably 310 CMR 7. No facility-specific orders or modifications to the SIP will be needed, and the project will not materially affect any planning documents demonstrating that the regulatory limits assure that the air will meet air quality standards.

B. Describe measures that the proponent will take to comply with other federal, state, regional, and local plans and policies related to air resources and air quality:

The MCPA application in Attachment D documents how the project will comply with all applicable federal and state regulations and policies. Through compliance with those regulations and policies the project will comply with the general requirement to avoid air pollution in Section 15.23.1 of the City of Cambridge, Massachusetts Zoning Ordinance.

SOLID AND HAZARDOUS WASTE SECTION

I. Thresholds / Permits

A. Will the project meet or exceed any review thresholds related to **solid or hazardous waste** (see 301 CMR 11.03(9))? ___ Yes _**X**_ No; if yes, specify, in quantitative terms:

B. Does the project require any state permits related to **solid and hazardous waste**? ___ Yes _**X**_ No; if yes, specify which permit:

C. If you answered "No" to both questions A and B, proceed to the **Historical and Archaeological Resources Section**. If you answered "Yes" to either question A or question B, fill out the remainder of the Solid and Hazardous Waste Section below.

II. Impacts and Permits

A. Is there any current or proposed facility at the project site for the storage, treatment, processing, combustion or disposal of solid waste? ___ Yes ___ No; if yes, what is the volume (in tons per day) of the capacity:

	Existing	Change	Total
Storage	_____	_____	_____
Treatment, processing	_____	_____	_____
Combustion	_____	_____	_____
Disposal	_____	_____	_____

B. Is there any current or proposed facility at the project site for the storage, recycling, treatment or disposal of hazardous waste? ___ Yes ___ No; if yes, what is the volume (in tons or gallons per day) of the capacity:

	Existing	Change	Total
Storage	_____	_____	_____
Recycling	_____	_____	_____
Treatment	_____	_____	_____
Disposal	_____	_____	_____

C. If the project will generate solid waste (for example, during demolition or construction), describe alternatives considered for re-use, recycling, and disposal:

D. If the project involves demolition, do any buildings to be demolished contain asbestos?
___ Yes ___ No

E. Describe the project's other solid and hazardous waste impacts (including indirect impacts):

III. Consistency

Describe measures that the proponent will take to comply with the State Solid Waste Master Plan:

HISTORICAL AND ARCHAEOLOGICAL RESOURCES SECTION

I. Thresholds / Impacts

A. Have you consulted with the Massachusetts Historical Commission? _X_ Yes ____ No; if yes, attach correspondence. For project sites involving lands under water, have you consulted with the Massachusetts Board of Underwater Archaeological Resources? ____Yes ____ No; if yes, attach correspondence

B. Is any part of the project site a historic structure, or a structure within a historic district, in either case listed in the State Register of Historic Places or the Inventory of Historic and Archaeological Assets of the Commonwealth? ___ Yes _X_ No; if yes, does the project involve the demolition of all or any exterior part of such historic structure? ___ Yes ___ No; if yes, please describe:

C. Is any part of the project site an archaeological site listed in the State Register of Historic Places or the Inventory of Historic and Archaeological Assets of the Commonwealth? ___ Yes _X_ No; if yes, does the project involve the destruction of all or any part of such archaeological site? ___ Yes ___ No; if yes, please describe:

D. If you answered "No" to all parts of both questions A, B and C, proceed to the **Attachments and Certifications** Sections. If you answered "Yes" to any part of either question A or question B, fill out the remainder of the Historical and Archaeological Resources Section below.

II. Impacts

Describe and assess the project's impacts, direct and indirect, on listed or inventoried historical and archaeological resources:

There are no historic resources within the project site. Several historic resources are located within the vicinity of the Project site including the following:

Map No.	Name	Address	Designation
1	Davenport/Allen & Endicott Factory	Osborn Street	NR/SR
2	NECCO Factory	250 Massachusetts Avenue	NR/SR
3	Metropolitan Storage Warehouse	134 Massachusetts Avenue	NRDOE/NRMRA/SR
4	Cambridge Armory	120 Massachusetts Avenue	NRDOE/NRMRA/SR
5	MIT Historic District	Massachusetts Avenue	NRDOE/NRMRA/SR
6	Charles River Basin Historic District		NR/SR
7	Old Cambridgeport Historic District	Cherry/Washington Streets	NR/SR

Attachment A-4 depicts the location of these resources in relation to the proposed project site. The 63 foot tall new building will have no effect of historic resources within the vicinity of the project site as buildings in the immediate vicinity are of similar scale. The proposed 165-foot stack will be visible from historic resources within the vicinity of the project site, however, the stack will result in no significant change to the existing setting and character of the area which is a densely developed urban area with several stacks of similar height in the vicinity.

III. Consistency

Describe measures that the proponent will take to comply with federal, state, regional, and local plans and policies related to preserving historical and archaeological resources:

The submittal of this ENF will initiate the Massachusetts Historical Commission's State Register review of the project (M.G. L. Chapter 9, Sections 27-27c, as amended).

CERTIFICATIONS:

1. The Public Notice of Environmental Review has been/will be published in the following newspapers in accordance with 301 CMR 11.15(1):

   (Name) Cambridge Chronicle (Date) 12/24/2015 and
   Boston Herald 12/18/2015

2. This form has been circulated to Agencies and Persons in accordance with 301 CMR 11.16(2).

Signatures:

12/14/2015 Donald Holmes	12/14/15 AJ Jablonowski
Date Signature of Responsible Officer or Proponent	Date Signature of person preparing ENF (if different from above)

Donald Holmes	AJ Jablonowski
Name (print or type)	Name (print or type)
MIT	Epsilon Associates, Inc.
Firm/Agency	Firm/Agency
77 Mass Ave, NE49-2100	3 Clock Tower Place, Suite 250
Street	Street
Cambridge, MA 02139	Maynard, MA 01754
Municipality/State/Zip	Municipality/State/Zip
(617) 324-6220	(978) 897-7100
Phone	Phone

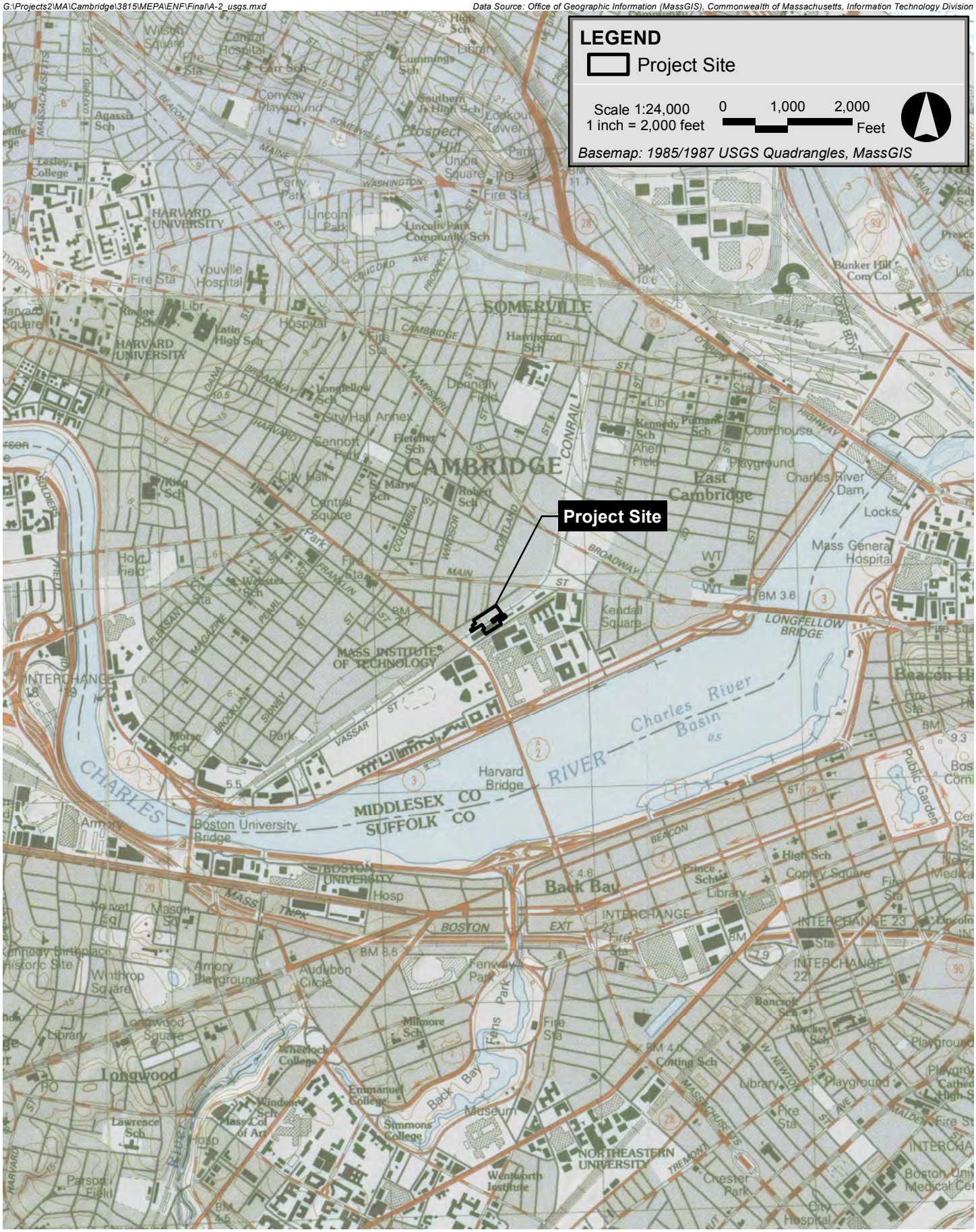
Attachment A

List of Attachments

ATTACHMENT A-1 LIST OF ATTACHMENTS

Attachment A-1	List of all attachments to this document.
Attachment A-2	U.S.G.S. Locus map
Attachment A-3	Aerial Locus Map
Attachment A-4	Environmental Constraints Map
Attachment A-5	Project Layout
Attachment A-6	Circulation List
Attachment B	Request for Single EIR
Attachment C	Expanded Narrative
Attachment D	MCPA Application (provided on CD)

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



MIT Cogeneration Project Cambridge, Massachusetts

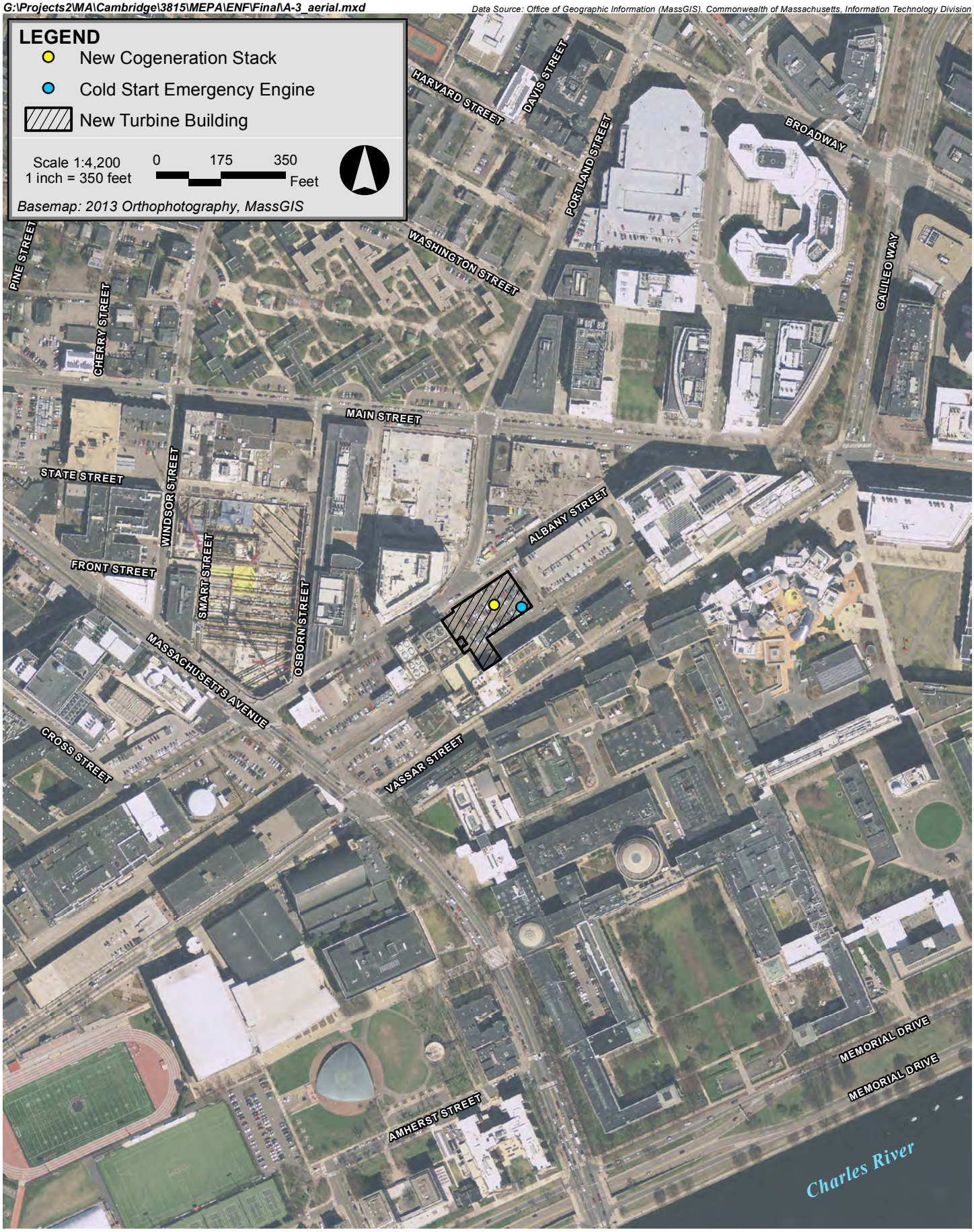
Epsilon ASSOCIATES INC.

Attachment A-2

USGS Locus Map

G:\Projects2\MA\Cambridge\3815\MEPA\ENF\Final\A-3_aerial.mxd

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



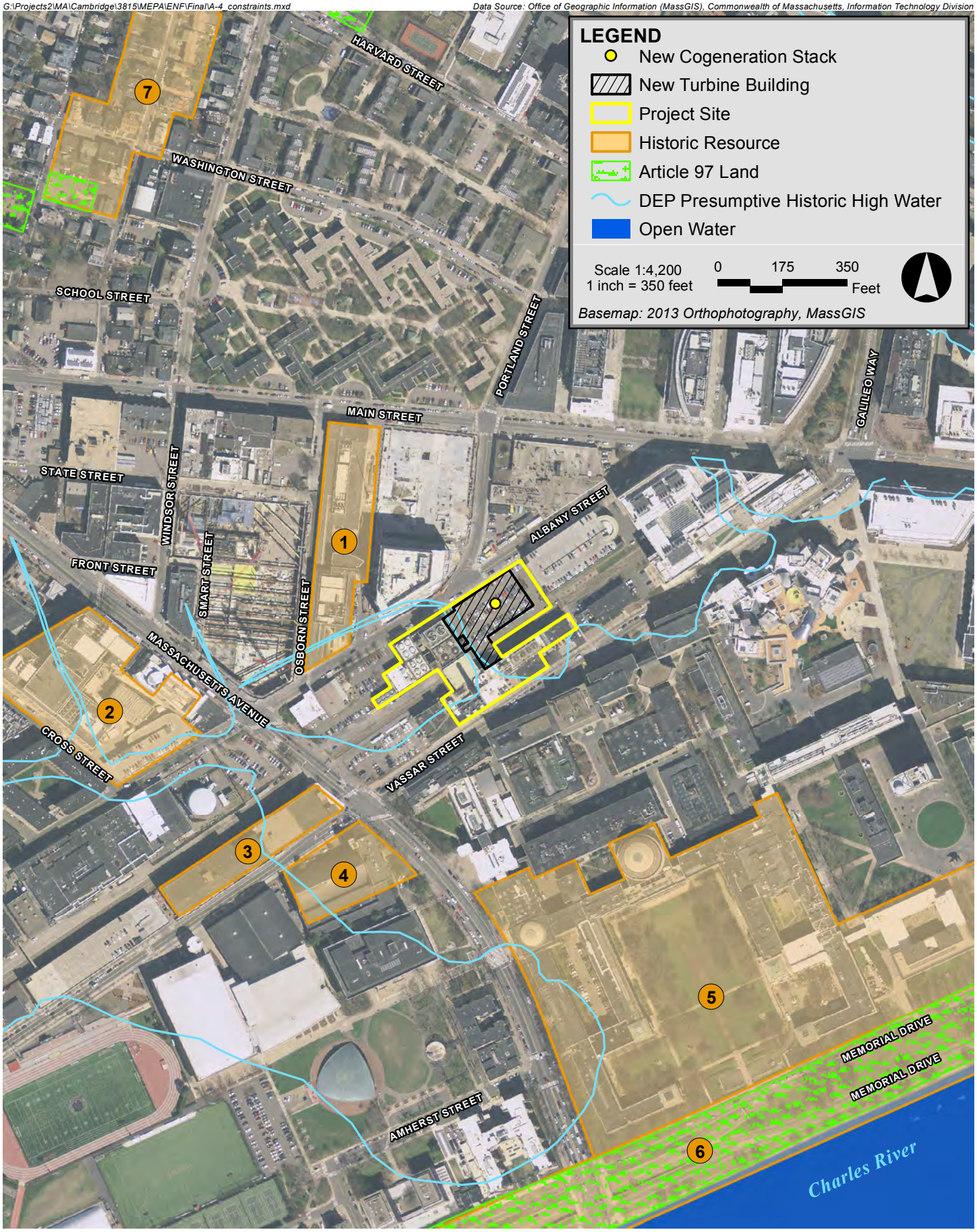
MIT Cogeneration Project Cambridge, Massachusetts

Epsilon ASSOCIATES INC.

Attachment A-3

Aerial Locus Map

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

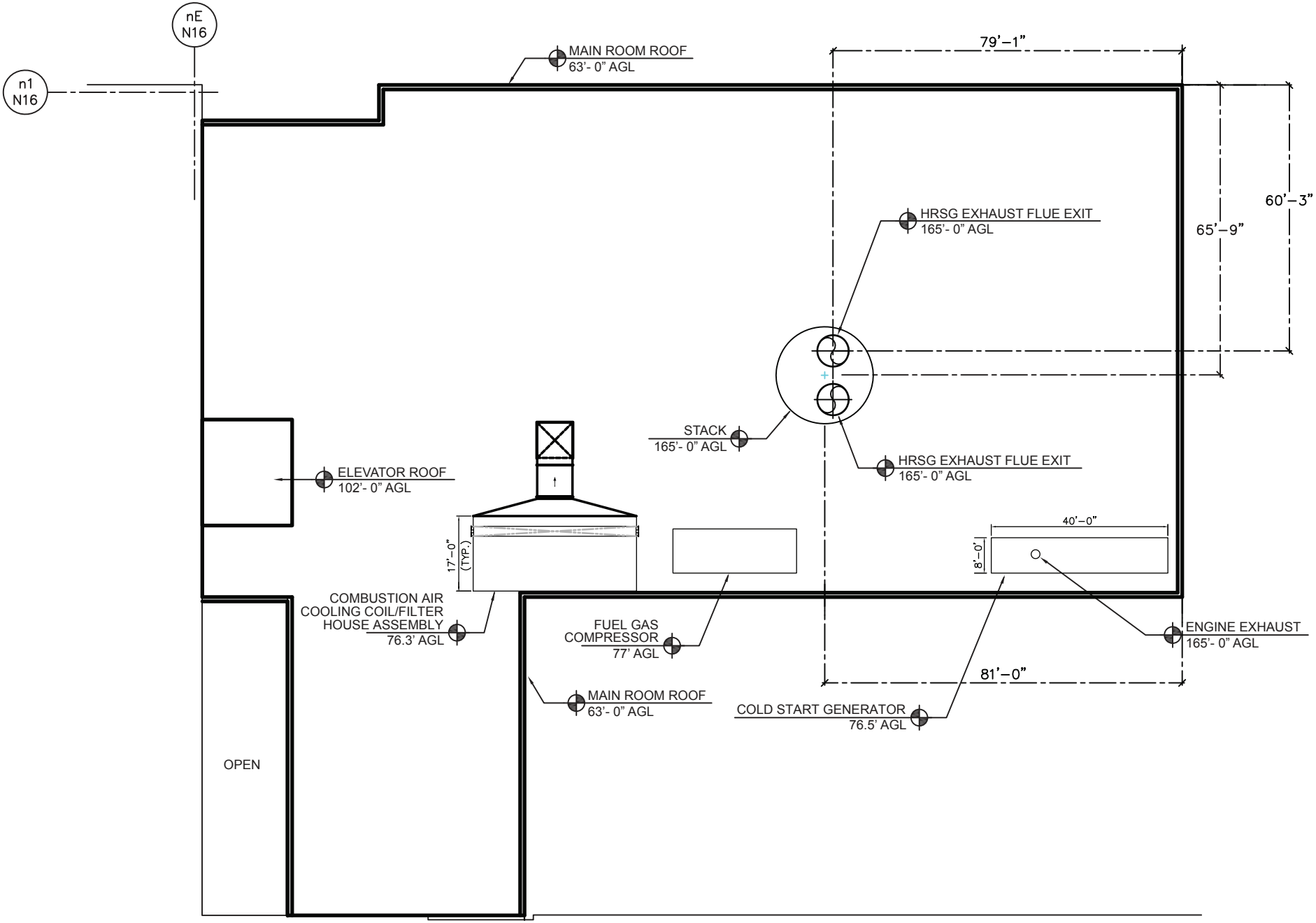


MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC.

Attachment A-4

Environmental Constraints



MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC

Attachment A-5

Project Layout/Site Plan

ATTACHMENT A-6 CIRCULATION LIST

Matthew A. Beaton, Secretary
Executive Office of Energy and
Environmental Affairs
Attn: MEPA Office
100 Cambridge Street, Suite 900
Boston, MA 02114

Department of Environmental Protection
Attn: Commissioner's Office/MEPA
Coordinator
One Winter Street
Boston, MA 02108

Department of Environmental Protection
Northeast Regional Office
Attn: MEPA Coordinator
205B Lowell Street
Wilmington, MA 01887

Massachusetts Department of Transportation
Public/Private Development Unit
10 Park Plaza
Boston, MA 02116

Massachusetts Department of Transportation
District #6
Attn: MEPA Coordinator
185 Kneeland Street
Boston, MA 02111

Massachusetts Historical Commission
The MA Archives Building
220 Morrissey Boulevard
Boston, MA 02125

Metropolitan Area Planning Council
60 Temple Place, 6th Floor
Boston, MA 02111

Department of Public Health
Director of Environmental Health
250 Washington Street
Boston, MA 02115

Energy Facilities Siting Board
Attn: MEPA Coordinator
One South Station
Boston, MA 02110

Division of Energy Resources
Attn: MEPA Coordinator
100 Cambridge Street, 10th floor
Boston, MA 02114

Massachusetts Water Resource Authority
Attn: MEPA Coordinator
100 First Avenue
Charlestown Navy Yard
Boston, MA 02129

Cambridge City Council
Attn: David P. Maher, Mayor
City Hall, 2nd Floor
795 Massachusetts Avenue
Cambridge, MA 02139

Community Development Department
City of Cambridge
344 Broadway
Cambridge, MA 02139

Cambridge Conservation Commission
344 Broadway
Cambridge, MA 02139

Cambridge Public Health Department
119 Windsor Street, Ground Level
Cambridge, MA 02139

Attachment B

Request for Single EIR

ATTACHMENT B

REQUEST FOR SINGLE ENVIRONMENTAL IMPACT REPORT

Central Utilities Plant Second Century Plant Expansion

TABLE OF CONTENTS

ATTACHMENT B – REQUEST FOR SINGLE ENVIRONMENTAL IMPACT REPORT B-1

B.1 Introduction B-1

B.2 Project Description B-1

B.3 MEPA Applicability B-2

B.4 Criteria for Allowing a Single EIR as Outlined in the MEPA Regulations B-2

B.4.1 Description of Project & Alternatives B-2

B.4.2 Baseline to Assess Impacts & Mitigation B-3

B.4.3 Demonstration that Impacts will be Avoided B-4

B.5 Conclusion B-4

ATTACHMENT B – REQUEST FOR SINGLE ENVIRONMENTAL IMPACT REPORT

B.1 Introduction

As summarized below and described more fully in the accompanying Expanded Environmental Notification Form (ENF), MIT is proposing an addition to its existing Central Utilities Plant (CUP) located on Vassar Street in Cambridge on the MIT campus. The addition will house two new nominal 22 megawatt (MW) combustion turbine (CT) units fired primarily on natural gas, one of which will replace the existing 20 MW CT, and a 2 MW Internal Combustion (IC) cold start engine. The project will also entail completing additional updates and energy conservation measures to reduce the campus energy usage including replacement of aging towers and more efficient chillers. The effort also includes changes to the operation of existing boilers, to eliminate non-emergency oil use and to allow use of the most efficient equipment. Finally, the project includes accessory mechanical equipment and a regulator station that gives Eversource access to high-pressure gas on campus.

MIT is requesting a single Environmental Impact Report (EIR) instead of a draft and final EIR. This request is for the following reasons, described more fully herein and in the Expanded ENF:

- Project impacts are generally limited to air quality and noise, which are addressed in the attached Major Comprehensive Plan Approval application submitted to MassDEP.
- As demonstrated in the accompanying Expanded ENF, the project will have little to no adverse impact to the environment, will provide greenhouse gas (GHG) benefits, and will improve the reliability and resiliency of campus electricity, heating, and cooling systems. Preparation of a draft and final EIR is unlikely to identify new issues or result in additional environmental protection.

For these and the reasons outlined below, MIT respectfully requests that the Secretary of the Executive Office of Energy and Environmental Affairs allow a single EIR for this project.

B.2 Project Description

To meet the anticipated electrical needs, MIT is proposing the Central Utilities Plant Second Century Plant Expansion Project, a 48 MW addition to MIT's existing CUP with the intent of meeting the following goals:

- To increase the resiliency of the campus, safeguarding crucial research by enabling MIT to function during a power-loss event;

- To equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and
- To continue conserving energy and reducing MIT's impact on the environment.

Additional project details are available in the ENF form and in the major CPA application in Attachment D.

B.3 MEPA Applicability

The project approaches or exceeds two MEPA review thresholds:

Threshold	Discussion
301 CMR 11.03 (7)(b)2. ENF. Expansion of an existing electric generating facility by 25 or more MW.	On a net, nominal basis, the proposed expansion is 23 MW, but there are conditions under which the expansion of total capacity could exceed 25 MW.
301 CMR 11.03 (8)(a)2. ENF and Mandatory EIR. Modification of an existing Stationery Source with federal potential emissions that collectively will result, after construction and the imposition of required controls, of 75,000 tpy of GHGs based on CO_2 Equivalent.	Proposed potential emissions from the project are approximately 286,000 tpy of CO_2.

The project does not exceed any other MEPA review thresholds.

B.4 Criteria for Allowing a Single EIR as Outlined in the MEPA Regulations

The MEPA Regulations at 301 CMR 11.06(8) outline a process by which the Secretary may allow a single EIR. In summary, the Secretary may allow a single EIR if the Expanded ENF describes all aspects of the project and alternatives, provides a baseline to assess impacts and mitigation, and demonstrates that the Project will use all feasible means to avoid environmental impacts. These criteria are discussed below.

B.4.1 Description of Project & Alternatives

In compliance with the MEPA Regulations, this Expanded ENF "describes and analyzes all aspects of the project and all feasible alternatives, regardless of any jurisdictional or other limitation that may apply to the Scope."

The ENF form includes a detailed discussion of the proposed project, as well as a discussion of additional project alternatives that MIT studied, including: Retire existing CT and purchase all electricity from utility (No Build alternative); Rebuilding existing CT with spare parts; Replace Existing CT with new turbine package in the location of the existing CT; and Expand existing capacity with new, approximately 30 MW turbine. These alternatives were analyzed using dispatch and financial models, and were then were ranked based on nine criteria: Capacity; Reliability/Availability; Constructability; Ease of commissioning; Equipment outage period for construction; Ease of operation; Maintainability; Disaster mitigation and recovery; and Campus Resiliency. These models and the comparison, as well as the environmental benefits, specifically fewer emissions, determined that the proposed project is the optimal option.

B.4.2 Baseline to Assess Impacts & Mitigation

In compliance with the MEPA Regulations, this Expanded ENF "provides a detailed baseline in relation to which potential environmental impacts and mitigation measures can be assessed." Specifically:

- Table D-14 in the MCPA application in Attachment D provides baseline observed ambient air quality concentrations in the area. The project will not cause or significantly contribute to violations of any ambient air quality standard, taking into account the baseline concentrations;

- Appendix E in the MCPA application in Attachment D provides measured background sound level data for twelve locations near MIT. The project's impacts will meet MassDEP regulations and guidance limiting noise increases above this baseline;

- The GHG analysis in Attachment C-5 provides a baseline case of comparable, state-of-the-art separate heat and power generation, to which potential GHG impacts and mitigation measures are assessed. This is consistent with EPA and MassDEP comparison methods; and

- The Expanded ENF form documents the baseline for facility acreage, size of structures, height of structures, traffic trips per day, water use, wastewater generation, and air emissions. Air emissions are addressed in detail in the MCPA application in Attachment D, water use is well within the supply capacity of the City of Cambridge, and no other material changes from the baseline are expected.

B.4.3 Demonstration that Impacts will be Avoided

In compliance with the MEPA Regulations, this Expanded ENF "demonstrates that the planning and design of the project use all feasible means to avoid potential environmental impacts."

The proposed project will allow MIT to provide reliable electricity, heating and cooling in a more efficient and environmentally conscious manner compared to relying on the utility grid. In addition, the project will be protected against potential future flooding.

As summarized below, any potential environmental impacts of the project will be minimal and appropriately mitigated.

- The MCPA application in Attachment D documents that the project's impacts to air quality will not cause or significantly contribute to the violation of any ambient air quality standard. It documents that impacts will be mitigated through use of cogeneration and the application of Best Available Control Technology (BACT), which includes the cleanest available fuels, efficient power and heat generation equipment, advanced combustion controls, and post-combustion catalytic controls.

- The GHG analysis in Attachment C-5 documents that the project offers an improvement over separate electricity and steam generation. It documents that impacts will be mitigated through the use of existing infrastructure, and the selection of energy efficient equipment.

B.5 Conclusion

MIT believes that the replacement of existing equipment and expansion of its CUP fully meets the criteria outlined in the MEPA regulations for allowing the preparation of a single EIR. The project is sited in an urban area having no natural resource constraints. It has been sustainably designed, it will use existing infrastructure, and it will have very minimal environmental impact. The Proponent is committed, and indeed will be obligated through the MassDEP plan approval process, to mitigate any unavoidable material impacts that may occur.

This Expanded ENF describes all aspects of the project and alternatives, provides a baseline to assess impacts and mitigation, and demonstrates that the project will use all feasible means to avoid environmental impacts. Preparation of a draft and final EIR is unlikely to result in additional environmental protection or less damage to the environment. For these reasons, the Proponent respectfully requests that the Secretary allow preparation of a single EIR.

Attachment C

Expanded Narrative

Table of Contents

ATTACHMENT C C-1

C-1 Overview and Description C-1
- C-1.1 Project Overview C-1
- C-1.2 Project Description C-3
- C-1.3 Applicable Regulatory Requirements C-9

C-2 Alternatives C-12
- C-2.1 Introduction C-12
- C-2.2 CUP Alternatives Reviewed C-12
- C-2.3 Other Alternatives Considered C-14
- C-2.4 Preferred Alternative C-14
- C-2.5 Comparison of Environmental Impacts C-15

C-3 Air Quality C-17
- C-3.1 Source Emissions Discussion C-17
- C-3.2 Emission Rates C-18
- C-3.3 Pollution Controls and Their Effectiveness C-19
- C-3.4 Best Available Control Technology (BACT) C-20
- C-3.5 Air Quality Impacts C-26

C-4 Noise C-41
- C-4.1 Summary of MCPA Noise Analysis C-41
- C-4.2 Consistency with Noise Policy C-43
- C-4.3 Avoidance, Minimization, and Mitigation C-45

C-5 GHG C-47
- C-5.1 GHG Policy Summary C-47
- C-5.2 Identifying Baseline & Proposed Cases C-48
- C-5.3 Quantifying Emissions C-49
- C-5.4 Other Mitigation C-49
- C-5.5 Minimize GHG Emissions: Turbine Selection C-50
- C-5.6 Minimize GHG Emissions: Balance of Plant C-51
- C-5.7 Concurrent Facility Upgrades C-53
- C-5.8 Available Energy Model Results C-53
- C-5.9 Conclusions and Commitments C-54

C-6 Environmental Justice C-55
- C-6.1 Introduction C-55
- C-6.2 Environmental Justice Analysis C-56
- C-6.3 Enhanced Public Participation C-57

C-7 Public Benefit Determination C-59
- C-7.1 Purpose and Effect of the Development C-60
- C-7.2 Impact on Abutters and the Surrounding Community C-60
- C-7.3 Enhancement to the Property C-61
- C-7.4 Benefits to the Public Trust Rights in Tidelands or Other Associated Rights C-61

Table of Contents (Continued)

C-7.5	Community Activities on the Development Site	C-61
C-7.6	Environmental Protection and Preservation	C-61
C-7.7	Public Health and Safety	C-62
C-7.8	General Welfare	C-62
C-7.9	Conclusion	C-62

List of Figures

Figure C-1	Campus Map	C-8
Figure C-2	Noise Measurement Locations	C-42
Figure C-3	Environmental Justice Areas	C-58

List of Tables

Table C-1	Key Existing Equipment at the MIT Plant	C-3
Table C-2	Buildings Served by MIT Plant	C-4
Table C-3	Summary of Applicable Requirements	C-10
Table C-4	Comparison of Environmental Impacts	C-15
Table C-5	Proposed Emission Rates for CTGs	C-18
Table C-6	Proposed Project Potential Emissions	C-19
Table C-7	Summary of PM effectiveness of clean fuels & combustion	C-23
Table C-8	Summary of CO_2e effectiveness of clean fuels & combustion	C-24
Table C-9	Top-Case BACT from MassDEP Guidance for Emergency IC Engines	C-25
Table C-10	Proposed Top-Case BACT for Boilers 7 and 9	C-26
Table C-11	National and Massachusetts Ambient Air Quality Standards, SILS, & PSD Increments	C-27
Table C-12	Physical Stack Characteristics for the New Sources	C-29
Table C-13	New Turbine Source Characteristics and Emission Rates for 1 Turbine with Duct Burner/HRSG (Operational Scenario 1)	C-29
Table C-14	New Turbine Source Characteristics and Emission Rates for 2 Turbines with Duct Burners/HRSGs (Operational Scenario 2)	C-30
Table C-15	New 2MW Cold Start Emergency Engine and Cooling Tower Source Characteristics and Emission Rates	C-31
Table C-16	Physical Stack Characteristics for the MIT Existing Sources	C-32
Table C-17	Worst-case Operating Conditions for Existing MIT Stacks by Pollutant and Averaging Period	C-33
Table C-18	Existing MIT Source Characteristics and Emission Rates	C-34
Table C-19	Observed Ambient Air Quality Concentrations and Selected Background Levels	C-35

List of Tables (Continued)

Table C-20	AERMOD Model Results for the Full MIT Facility for Operational Scenarios 1 & 2 Compared to the NAAQS[1]	C-37
Table C-21	AERMOD Model Results for the Full MIT Facility with Interactive Sources for Operational Scenarios 1 &2 Compared to the NAAQS	C-39
Table C-22	CITY OF CAMBRIDGE ZONING DISTRICT NOISE STANDARDS (ref: Table 8.16.060E)	C-44
Table C-23	Sound Level Modeling Results Summary Table	C-45
Table C-24	Estimates of Project-Only Sound Pressure Levels and Overall A-Weighted Sound Levels	C-45
Table C-25	GHG Quantification	C-54

ATTACHMENT C

C-1 Overview and Description

C-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."*

---

[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).

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, & 6 with three new cooling towers 11, 12, & 13. Existing cooling towers 7, 8, 9 and 10 will remain.

C-1.2 Project Description

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).

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

Table C-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.

The CUP provides energy (electricity, heating, and/or cooling) to the buildings listed in Table C-2, below. Building locations are shown on the campus map, Figure C-1.

Table C-2 Buildings Served by MIT Plant

Building Number	*Building Name*	*Street Address*	*ELECTRICITY*	*HEATING*	*COOLING*
1	PIERCE LABORATORY	33 MASSACHUSETTS AVE	X	X	X
2	BUILDING 2	182 MEMORIAL DR	X	X	X
3	MACLAURIN BUILDINGS (3)	33 MASSACHUSETTS AVE (REAR)	X	X	X
4	MACLAURIN BUILDINGS (4)	182 MEMORIAL DR (REAR)	X	X	X
5	PRATT SCHOOL	55 MASSACHUSETTS AVE	X	X	X
6	EASTMAN LABORATORIES	182 MEMORIAL DR (REAR)	X	X	X
6B	SOLVENT STORAGE	182 MEMORIAL DR (REAR)	X	X	X
6C	BUILDING 6C	182 MEMORIAL DR (REAR)	X	X	X
7	WILLIAM BARTON ROGERS BUILDING	77 MASSACHUSETTS AVE	X	X	X
7A	ROTCH LIBRARY EXTENSION	77 MASSACHUSETTS AVE	X	X	X
8	BUILDING 8	21 AMES ST	X	X	X
9	SAMUEL TAK LEE BUILDING	105 MASSACHUSETTS AVE	X	X	X
10	MACLAURIN BUILDINGS (10)	222 MEMORIAL DR	X	X	X
11	HOMBERG BUILDING	77 MASSACHUSETTS AVE (REAR)	X	X	X
13	BUSH BUILDING	105 MASSACHUSETTS AVE (REAR)	X	X	X
14	HAYDEN MEMORIAL LIBRARY	160 MEMORIAL DR	X	X	X
16	DORRANCE BUILDING	21 AMES ST	X	X	X
17	WRIGHT BROTHERS WIND TUNNEL	76 VASSAR ST	X		X
18	DREYFUS BUILDING	21 AMES ST	X	X	X
24	BUILDING 24	60 VASSAR ST	X	X	X
26	COMPTON LABORATORIES	60 VASSAR ST	X	X	X
31	SLOAN LABORATORIES	70 VASSAR ST (REAR)	X	X	X
32	STATA CENTER	32 VASSAR ST	X	X	X
32P	STATA CENTER GARAGE	32 VASSAR ST	X	X	X
33	GUGGENHEIM LABORATORY	125 MASSACHUSETTS AVE	X	X	X
34	EG&G EDUCATION CENTER	50 VASSAR ST	X	X	X
35	SLOAN LABORATORY	127 MASSACHUSETTS AVE	X	X	X
36	FAIRCHILD BUILDING (36)	50 VASSAR ST	X	X	X
37	MCNAIR BUILDING	70 VASSAR ST	X	X	X
38	FAIRCHILD BUILDING (38)	50 VASSAR ST	X	X	X
39	BROWN BUILDING	60 VASSAR ST	X	X	X

Table C-2 Buildings Served by MIT Plant (Continued)

Building Number	*Building Name*	*Street Address*	*ELECTRICITY*	*HEATING*	*COOLING*
41	BUILDING 41	77 VASSAR ST	X	X	X
42	COGENERATION PLANT	59 VASSAR ST	X	X	X
43	POWER PLANT ANNEX	57 VASSAR ST	X	X	X
44	CYCLOTRON	51 VASSAR ST	X		X
46	BCSC	43 VASSAR ST	X		
48	PARSONS LABORATORY	15 VASSAR ST	X	X	X
50	WALKER MEMORIAL	142 MEMORIAL DR	X		X
51	WOOD SAILING PAVILION	134 MEMORIAL DR	X		X
54	GREEN BUILDING	21 AMES ST	X	X	X
56	WHITAKER BUILDING	21 AMES ST	X	X	X
57	MIT ALUMNI POOL	6 VASSAR ST	X		X
62	ALUMNI HOUSES: MUNROE HAYDEN WOOD	3 AMES ST (REAR)	X		X
64	EAST CAMPUS: WALCOTT BEMIS GOODALE	3 AMES ST	X		X
66	LANDAU BUILDING	25 AMES ST	X	X	X
68	KOCH BIOLOGY BUILDING	31 AMES ST	X	X	X
76	D H KOCH IN FICR	500 MAIN ST	X	X	X
E1	GRAY HOUSE	111 MEMORIAL DR	X		X
E2	SENIOR HOUSE	4 AMES ST	X	X	X
E14	BUILDING E14	75 AMHERST ST	X	X	X
E15	WIESNER BUILDING	20 AMES ST	X	X	X
E17	MUDD BUILDING	40 AMES ST	X	X	X
E18	FORD BUILDING (E18)	50 AMES ST	X	X	X
E19	FORD BUILDING (E19)	400 MAIN ST	X	X	X
E23	HEALTH SERVICES	25 CARLETON ST	X	X	X
E25	WHITAKER COLLEGE	45 CARLETON ST	X	X	X
E33	RINALDI TILE	34 CARLETON ST	X		X
E34	BUILDING E34	42-44 CARLETON ST	X	X	X
E38	SUFFOLK BUILDING	292 MAIN ST	X	X	X
E40	MUCKLEY BUILDING	1 AMHERST ST	X	X	X
E51	TANG CENTER	70 MEMORIAL DR	X	X	X
E52	SLOAN BUILDING	50 MEMORIAL DR	X	X	X
E53	HERMANN BUILDING	30 WADSWORTH ST	X	X	X
E55	EASTGATE	60 WADSWORTH ST	X	X	X
E60	ARTHUR D LITTLE BUILDING	30 MEMORIAL DR	X		
E62	BUILDING E62	100 MAIN ST	X		
N4	ALBANY GARAGE	32 ALBANY ST	X		X
N9	SUPERCONDUCTING TEST FACILITY	68 ALBANY ST	X		X

Table C-2 Buildings Served by MIT Plant (Continued)

Building Number	*Building Name*	*Street Address*	*ELECTRICITY*	*HEATING*	*COOLING*
N10	HIGH VOLTAGE RESEARCH LAB	155 MASSACHUSETTS AVE	X		X
N16	COOLING TOWER & OIL RESERVE	60 ALBANY ST	X		
N16A	BUILDING N16A	60 ALBANY ST	X		
N16B	FIRE PUMP ROOM	60 ALBANY ST	X		
N16C	BUILDING N16C	60 ALBANY ST	X		
W1	FARIBORZ MASEEH HALL	305 MEMORIAL DR	X		X
W2	BUILDING W2	311 MEMORIAL DR	X	X	X
W4	MCCORMICK HALL	320 MEMORIAL DR	X	X	X
W5	GREEN HALL	350 MEMORIAL DR	X		
W7	BAKER HOUSE	362 MEMORIAL DR	X	X	X
W8	PIERCE BOATHOUSE	405 MEMORIAL DR	X		X
W15	MIT CHAPEL	48 MASSACHUSETTS AVE (REAR)	X	X	X
W16	KRESGE AUDITORIUM	48 MASSACHUSETTS AVE (REAR)	X	X	X
W20	STRATTON STUDENT CENTER	84 MASSACHUSETTS AVE	X	X	X
W31	DU PONT ATHLETIC GYMNASIUM	120 MASSACHUSETTS AVE	X		X
W32	DU PONT ATHLETIC CENTER	100 MASSACHUSETTS AVE	X	X	X
W33	ROCKWELL CAGE	106 VASSAR ST	X	X	X
W34	JOHNSON ATHLETICS CENTER	120 VASSAR ST	X	X	X
W35	SPORTS & FITNESS CENTER	120 VASSAR ST	X	X	X
W45	WEST GARAGE	125 VASSAR ST	X		X
W51	BURTON-CONNER HOUSE	410 MEMORIAL DR	X		X
W53	CARR INDOOR TENNIS FACILITY	410 MEMORIAL DR (REAR)	X		X
W53A	CARR INDOOR TENNIS FACILITY (OFFICE)	410 MEMORIAL DR (REAR)	X		X
W53B	DUPONT TENNIS COURTS (OFFICE)	410 MEMORIAL DR (REAR)	X		X
W53C	BUILDING W53C	410 MEMORIAL DR (REAR)	X		X
W53D	CARR INDOOR TENNIS FACILITY(SVC)	410 MEMORIAL DR (REAR)	X		X
W56	BUILDING W56	169 VASSAR ST	X		
W57	BUILDING W57	169 VASSAR ST	X		
W57A	BUILDING W57A	169 VASSAR ST	X		
W61	MACGREGOR HOUSE	450 MEMORIAL DR	X	X	X

Table C-2 Buildings Served by MIT Plant (Continued)

Building Number	*Building Name*	*Street Address*	*ELECTRICITY*	*HEATING*	*COOLING*
W70	NEW HOUSE	471-476 MEMORIAL DR	X	X	X
W71	NEXT HOUSE	500 MEMORIAL DR	X	X	X
W79	SIMMONS HALL	229 VASSAR ST	X	X	X
W84	TANG HALL	550 MEMORIAL DR	X	X	X
W85	WESTGATE	540 MEMORIAL DR (REAR)	X	X	X
W85ABC	WESTGATE (ABC)	11-13-15 AUDREY ST	X	X	X
W85DE	WESTGATE (DE)	292-290 VASSAR ST	X	X	X
W85FG	WESTGATE (FG)	286-284 VASSAR ST	X	X	X
W85HJK	WESTGATE (HJK)	282-280-278 VASSAR ST	X	X	X
W91	INFORMATION SYSTEMS OPERATIONS	565-570 MEMORIAL DR	X		X

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.

Figure C-1

Campus Map

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.

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. 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).

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.

C-1.3 Applicable Regulatory Requirements

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.

Regulatory requirements are summarized in Table C-3.

Table C-3 Summary of Applicable Requirements

Regulatory Program	Brief Description	Applicability
Ambient Air Quality Standards and Policies	Limitations on concentrations of specific criteria pollutants in public areas to protect public health and welfare.	Applies, and air quality dispersion modeling in the air plan approval process documents that the Project will not cause or significantly contribute to any violation of ambient air quality standards.
Prevention of Significant Deterioration (PSD) Review	PSD is designed to protect public health and welfare by ensuring that no major new sources or modifications to existing sources significantly decrease the quality of ambient air. PSD requires applicants to perform a Best Available Control Technology (BACT) analysis, an air quality analysis, and have public involvement in the approval process.	Applies and is the subject of a PSD air permit application.
Non-Attainment New Source Review	Requirements that apply to areas not in attainment with the Ambient Air Quality Standards. These requirements include the installation of the Lowest Achievable Emission Rate (LAER), emission offsets, and the opportunity for public involvement.	Does not apply because the Project does not have potential emissions of Non-Attainment Pollutants above regulatory thresholds.
New Source Performance Standards	Federal Air Pollution Emission Standards that establish what the acceptable level of pollution that new stationary sources can produce.	The CT's are subject to 40 CFR 60 Subpart KKKK. The cold-start -emergency engine is subject to 40 CFR 60 Subpart IIII. Boilers 7 and 9 continue to be subject to 40 CFR 60 Subparts Dc and Db, respectively.
National Emission Standards for Hazardous Air Pollutants	Federal stationary source standards for hazardous air pollutants (HAPs). These standards cover HAPs that are not directly covered by the Ambient Air Quality Standards.	Subpart ZZZZ for cold-start engine.
Emissions Trading Programs	Program that sets a cap on emissions while also creating allowances to emit up to the cap. Sources can then buy or sell allowances or save them for use in future years. Sources can buy/trade allowances with other sources as well. Sources must hold enough allowances to cover their emissions.	The new CT's are subject to 310 CMR 7.32 as applicable. The new units are too small to be subject to the federal Acid Rain Program or the Regional Greenhouse Gas Initiative.
Visible Emissions	Massachusetts limits on the amount of visible emissions a source can emit, measured by opacity.	Applies and will be complied with.
Noise Control Regulation and Policy	Massachusetts limits on the amount of noise a source can generate above ambient levels.	Applies and is satisfied through the noise analysis in the air plan approval process

Table C-3 Summary of Applicable Requirements (Continued)

Regulatory Program	Brief Description	Applicability
Air Plan Approval	Requires sources to get approval for air emissions and obtain a permit to operate the source.	Applies and is satisfied through the air plan approval application
Operating Permit	Facilities are required to hold an up to date operating permit from the governing body. This permit allows the facility to operate under certain limitations set forth by the governing body.	Applies and will be satisfied through an operating permit modification application after the air plan approval is issued.
Compliance Assurance Monitoring	Requires demonstration of compliance with applicable requirements for large emission units that rely on pollution control devices to achieve compliance with limitations.	Does not apply because the controlled pollutants will have continuous emissions monitoring.
Historic Railroad 40 §54A permit	Any construction project in Massachusetts that involves land formerly used by a railroad company or as a railroad right-of-way requires a local permit from MassDOT.	Applies and will be satisfied through a request for consent document, with a period of public review and comment.
Massachusetts Environmental Policy Act (MEPA) Review	Requirement for state agencies to study environmental consequences of approval before permitting a new source. MEPA also requires that all feasible measures are taken to avoid, minimize, and mitigate damage to the environment.	Applies and will be satisfied through this Expanded ENF and subsequent Environmental Impact Report

C-2 Alternatives

C-2.1 Introduction

Due to the existing site and building conditions, the on-site alternatives would be limited to a smaller CHP unit that would not meet the long term needs of MIT, or nothing could be done and MIT would over time need to find alternative methods to meet their electric, steam and cooling (such as outside, less efficient generating facilities or units). Given the space available at the existing site, the facility's efficiency at producing electricity, steam and chilled water, and the proximity to the buildings on campus it will provide for, installing the CUP upgrade/attachment is the only feasible alternative.

C-2.2 CUP Alternatives Reviewed

As mentioned above, the existing CTG is nearing the end of its service life. To continue to meet the expected electric and steam needs of its campus, MIT examined five options to replace the existing CTG, as discussed below.

Option 1 (No-Build option) - Retire existing CTG and purchase all electricity from utility

In the No-Build Alternative, the existing MIT Central Utilities Plant facility would remain open, and the proposed CoGen system would not be installed. To offset the loss of the existing cogeneration heat recovery steam boiler, MIT would have to install an additional boiler to maintain firm steam capacity on campus. In the short term, MIT would continue to operate as it currently does, with fuel use and air emissions approximately unchanged. As demand increases on the MIT campus, the No-Build Alternative would have two effects:

1. More electricity would be imported from the grid; and

2. MIT would operate boilers that are less efficient than the CHP process to meet the demand for heating and cooling.

The environmental impacts of increased electricity imports would include additional air quality impacts at the electric generation sources and a potential decrease in grid reliability associated with the extra load. Although this option simplifies the operation of the CUP, the elimination of the generating capacity exposes the campus to outages of the grid without local backup. With the increasing demand on the grid and the increasing frequency of severe storms, the grid's reliability can be expected to be challenged. The environmental impacts of additional use of older equipment at the MIT facility would include increased air emissions (although this would not cause air quality to exceed any National Ambient Air Quality Standard (NAAQS)). As demand increases, the No-Build Alternative would result in greater environmental impacts, grid stress, reduced campus resiliency, and increased imported utility cost to MIT. The life cycle cost of this option is higher than the other options considered.

Option 2 - Rebuilding existing CTG with spare parts

This option would include upgrading the CTG to a level the manufacturer would support through a new Long Term Service Agreement (LTSA). This LTSA would provide support for approximately ten years after construction. It is unlikely that the service contract would be extended after the ten-year term as this would constitute the third service life extension on the 1993 gas turbine. Under this scenario, MIT would install a new CTG at year 11 in order to meet the comparative 20-year life. This option would add a small increase in the capacity of the system due to increased efficiency and newer components. During normal operation, the grid would provide backup capacity for the system in the event of component failure or service interruption. Select campus loads would be covered in an island mode if the CTG is available at the same time as a utility grid outage. This option would require MIT to continue to rely on older, less efficient equipment and technology, and would not provide the environmental benefits of a new turbine package. This option would also be anticipated to be susceptible to flooding in the future. In addition, the life cycle cost of this option is the second highest of the five options considered.

Option 3 - Replace Existing CTG with new turbine package in the location of the existing CTG

In this option, the existing CTG would be replaced by a new nominal 22 MW unit and would have new auxiliaries. The engine reliability, availability, and efficiency would be improved over Option 2. During normal operation, the grid would provide backup capacity for the system in the event of component failure or service interruption. Select campus loads would be covered in an island mode if the CTG is available at the same time as a utility grid outage. This option would be anticipated to be susceptible to flooding in the future. In addition, the life cycle cost of this option is higher than the proposed project. In addition, MIT would have an increased dependence on the grid for its future electrical needs, which would create more emissions than the proposed project.

Option 4 - Expand existing capacity with new, approximately 30 MW turbine

This option would replace the existing 21 MW CTG with a larger 30 MW CTG. This option would offer the same increase in reliability as Option 3 with new CTG packaged equipment. The new package in this option would be installed in a new addition, including newer support systems and components elevated to protect against flooding. The need for higher gas pressure would require the use of a fuel gas compressor for this higher capacity unit. The installation of a single new combustion turbine does not provide the reliability that a redundant system offers. In addition, MIT would have an increased dependence on the grid for its future electrical needs, which would create more emissions than the proposed project.

Option 5 (Proposed project) - Expand existing capacity with two new turbines

This option is the proposed project, which allows for redundancy to minimize dependence on the utility grid, will be protected against flooding, and offers the lowest life cycle cost. In addition, more energy would be created by the cogeneration plant, resulting in fewer air emissions due to a decreased need to rely on less efficient energy methods (e.g., the electric grid, stand-alone boilers).

C-2.3 Other Alternatives Considered

Regarding other alternatives considered by MIT:

- A CUP expansion powered by other fuels (e.g. oil, biomass) would not provide the reliability offered by a natural gas-fired project, supported by firm gas capacity. Also, local air quality impacts would be higher, fuel storage would be difficult, and transportation impacts would be substantial.

- A project with no capability to fire ULSD during emergencies would provide less resiliency than the proposed project, would negatively impact the electrical grid during emergencies, and would not meet the project's reliability goals.

- The use of onsite renewable energy, and the reduction in energy use, is being actively pursued campus-wide as part of MIT's ongoing commitment to reduce campus greenhouse gas emissions. Neither strategy would eliminate the need for campus energy services. The proposed project will allow MIT to reduce environmental impacts on a growing campus in conjunction with alternative energy generation and energy use reductions.

- The purchase of offsite renewable energy is also being pursued as part of MIT's ongoing commitment to reduce campus greenhouse gas emissions, but this strategy would not meet the project's goals of increasing energy reliability and campus resiliency (the campus would remain dependent on the grid for transportation).

C-2.4 Preferred Alternative

As described above, the Preferred Alternative consists of the installation of two nominal 22 MW CTGs. Each CTG will exhaust to its own HRSG with a 134 million Btu per hour (MMBtu/hr) higher heating value (HHV) gas fired duct burner. The proposed project is described in detail in section C-1 above.

The project turbine selection is not final, and options are being considered for two slightly smaller CTGs and duct burners. Generally, the project as described is the largest of the options being considered; other options would maintain the same general configuration and operation while producing less power and having lower impacts.

Each CTG 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. 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). The exhaust from each CT + HRSG combo will vent through a 165′ AGL high flue centrally co-located in a common stack structure.

There would need to be construction in order to house the new CoGen project. 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.

Proposed mitigation measures under the Preferred Alternative include, fundamentally, the use of CHP to maximize energy efficiency, the use of existing infrastructure, and the selection of efficient equipment. Additionally, the use of the cleanest available fuels, advanced combustion design, and air pollution control catalysts would minimize air quality impacts under the Preferred Alternative. All new equipment will be ensured to have minimal noise impact as discussed in section C-4 below.

C-2.5 Comparison of Environmental Impacts

Table C-4 below describes and compares the anticipated environmental impacts of the No-Build and Preferred Alternatives.

Table C-4 Comparison of Environmental Impacts

Impact	No-Build	Preferred Alternative
Air Quality	MIT will need to obtain electricity, steam heat, and chilled water from an outside source to supplement the existing Central Utilities Plant. This would apply across its more than 100 MIT-related buildings. The units generating the electricity, steam heat, and chilled water are unlikely to be as efficient as the proposed CoGen project and will likely generate more pollution for the same generation needs. Installation of a new boiler would be needed for reliability.	The Preferred Alternative will use Best Available Control Technology (BACT) to minimize air emissions. Ambient impacts of the project will not cause or significantly contribute to exceedance of any air quality standard. MassDEP will review the control technologies and predicted impacts as described in the MCPA. Compliance will be documented through operational controls, stack testing, and continuous emissions monitoring systems.

Table C-4 Comparison of Environmental Impacts (Continued)

Impact	No-Build	Preferred Alternative
Greenhouse Gas Emissions	Without the proposed CoGen project, older units that are more polluting will need to run more often, resulting in an increase in GHG emissions. One new boiler would be added, but it would be less efficient overall than the proposed CoGen project. MIT will also potentially have to outsource some of its steam heat, electricity, and chilled water generation needs to plants running less efficient older units that will generate more GHG emissions for the same generation needs.	The greenhouse gas (GHG) analysis (Section C-5 of this document) documents that the Preferred Alternative will reduce GHG emissions compared to separate heat and power generation, and that the project will mitigate GHG impacts to the maximum extent feasible through the selection of efficient generation and support equipment.
Noise	The baseline case involves some incremental additional operation of existing MIT equipment (and a new boiler) onsite and some additional incremental operation of electric generating equipment offsite. This could potentially generate some incremental outside noise.	The noise section (section C-4 of this document) provides an in-depth analysis of noise impacts of the Preferred Alternative. The CHP equipment will be located near existing railroad tracks and support systems. The CTG will be enclosed, and the compressor and cold start engine will be installed in sound-attenuated enclosures. The project incorporates sound mitigation to minimize noise impact.
Infrastructure	A new boiler (sized to provide approximately 100,000 pounds/hour of steam) would be added for reliability. If the project does not proceed, it could influence decisions elsewhere on the MIT campus to install equipment.	The Preferred Alternative will be installed in an attachment to an existing building. This attachment would be on an existing parking lot on the MIT campus.

Table C-4 Comparison of Environmental Impacts (Continued)

Impact	No-Build	Preferred Alternative
Historic Resources	Depending on final boiler location, the No-Build case would have no impact to Historic Resources. If the project does not proceed, it could influence decisions elsewhere on the MIT campus to install equipment, which could have an impact.	There are no historic resources listed on the State or National Registers of Historic Places or included in the Inventory of Historic and Archaeological Assets of the Commonwealth on the project site; several such sources are located in the vicinity. The project is unlikely to affect significant historic resources as it is located within a densely developed urban area with similarly scaled structures.
Construction	The Baseline case would have no major construction, although MIT would still proceed with the installation of a boiler and new electrical switchgear. If the project does not proceed, it could influence decisions elsewhere on the MIT campus to install equipment, which could have an impact.	Construction-related impacts will generally be limited to the project site and immediately adjacent streets (Albany and Vassar Streets). During the construction of the new plant, there will be some short-duration impacts to the traffic and surrounding streets, which will be reviewed and approved by the City of Cambridge and will be designed to minimize impact when possible. Construction work will also involve managing the flow of foot traffic to ensure the safety of pedestrians.

C-3 Air Quality

C-3.1 Source Emissions Discussion

The Project will combust natural gas (with ULSD backup) to generate electricity and steam. Generally, the combustion (burning) process involves combining the hydrocarbon fuel with oxygen to create carbon dioxide and water vapor. Carbon dioxide emissions are addressed in the greenhouse gas section (Section C-5). The water vapor has no measureable impact on local climate or humidity.

The two new CT's will emit products of combustion from the firing of natural gas or ULSD. Air pollutants can be generated in the combustion process in three ways. First, incomplete combustion can allow the emission of carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM). Second, high-temperature combustion can cause nitrogen in the air to oxidize to nitrogen oxides (NOx). Third, impurities in the fuel can allow emissions of sulfur dioxide (SO2), NOx, and PM. Emissions are minimized through the use of clean burning fuels, in combination with post combustion controls.

MIT minimizes the CO and VOC emissions through good combustion control, and use of an oxidation catalyst (similar to the catalytic converters installed on automobiles). The NOx emissions are minimized through low-NOx combustors and use of selective catalytic reduction (that reverses the reaction that forms NOx). Because proposed ULSD use is very limited, the new CT's have the opportunity to use dry low-NOx combustors instead of water injection. MIT minimizes the emissions from fuel impurities by using the cleanest available fuels (natural gas and ULSD).

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.

MassDEP is reviewing the MCPA application for MIT. Per the MCPA regulation at 310 CMR 7.02(3)(j), MassDEP will only issue an approval if the Project will comply with air quality rules, utilize BACT, and not result in air quality exceeding either the Massachusetts or National Ambient Air Quality Standards (MAAQS or NAAQS).

C-3.2 Emission Rates

The new expansion will emit products of combustion from the firing of natural gas or ULSD. Emissions are minimized through as specified in the above section. Potential short-term and long-term emission rates of the CHP (turbine and duct-burner) are summarized below.

Table C-5 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 C-6 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

C-3.3 Pollution Controls and Their Effectiveness

The primary method that the Project will use to minimize air emissions will be to avoid the unnecessary generation of air emissions. Modern combustion turbines are designed and operated to ensure complete combustion, and avoid "hot spots" which could generate NOx. The Project will use the cleanest available fuels (natural gas and ULSD backup).

The proposed post-combustion pollution controls are a selective catalytic reduction (SCR) system and an oxidation catalyst. EPA[2] describes SCR as follows:

> *"The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen."*

EPA[3] describes catalytic oxidation as follows:

> *"Carbon monoxide oxidation catalysts are typically used on turbines to achieve control of CO emissions... CO catalysts are also being used to reduce VOC and organic HAPs emissions... The CO catalyst promotes the oxidation of CO and hydrocarbon compounds to carbon dioxide (CO2) and water (H2O) as the emission stream passes through the catalyst bed. The oxidation process takes place spontaneously, without the requirement for introducing reactants."*

---

[2] EPA-423/F-03-032 Air Pollution Control Technology Fact Sheet – Selective Catalytic Reduction.

[3] EPA AP 42, Fifth Edition, Volume I, Section 3.1.4.3.

Proposed Project emission rates are based on the operation of these pollution control systems to meet BACT as described below. The systems will be designed and operated to meet BACT limits over the full range of operating conditions. Pollution control efficiency is therefore more a function of the pre-control emission rates than the post-combustion systems themselves. Based on turbine exhaust data, and BACT emission limits as discussed below, the SCR system will control about 92% of NOx emissions, and the oxidation catalyst will control about 96% of CO emissions.

C-3.4 Best Available Control Technology (BACT)

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). Different pollutants are subject to different BACT requirements.

The plan approval requirements at 310 CMR 7.02(5) require BACT. BACT is defined in 310 CMR 7.00 as,

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

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

MassDEP has a lengthy history of determining BACT for combustion sources of the size proposed for the CHP expansion, and has applicable regulations and guidance defining "top-case BACT." For pollutants where top-case BACT is proposed, a detailed, exhaustive top-down analysis would be "reinventing the wheel." This application presents a formal BACT analysis for PM, CO, VOC and CO_2, and relies on MassDEP guidance and information from other available resources for other pollutants. Also, a separate BACT analysis is provided for the proposed ULSD fired cold-start engine.

Top-Case BACT from MassDEP Guidance for Combustion Turbines & Duct Burners

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources[4] to document BACT. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Specifically, MIT the emission rates in Table C-5 above are consistent with MassDEP guidelines for top-case BACT for all pollutants for which guidelines are available (NOx, CO, VOC, NH3).

While not specifically listed in the MassDEP guidance, MIT proposes the following as top-case BACT:

- Sulfur dioxide (SO2) BACT is met through the use of low-sulfur fuels (natural gas and ultra-low sulfur diesel), and efficient operation. MIT will track sulfur content through vendor-posted data and fuel receipts.

Proposed Variations from Top-case BACT

MIT proposes the following changes from Massachusetts guidance for Top-Case BACT:

- MIT proposes a NOx emission rate of 9 ppmvd at 15% O2 when firing ULSD, instead of the Massachusetts top-case BACT guidance of 7 ppmvd at 15% O2. This proposed change allows the use of a dry low-NOx combustor for the CTGs, which has environmental and reliability benefits.

- MIT proposes to meet other top-case BACT guidance during full-load, steady state conditions. However, the CTGs must be able to quickly and reliably respond to changes in campus energy demand. Meeting the same limits as apply for full-load steady-state conditions will not be possible over the short term. The proposed emission limits during part-load and transient operations are:

    - Proposed NOx firing gas from the CTG of 3.2 ppmvd at 15% O2 during operation below 90% load.

    - Proposed NOx firing gas from the CTG of 4.0 ppmvd at 15% O2 during operation below 90% load and ambient air temperatures below 30 degrees Fahrenheit.

---

[4] http://www.mass.gov/eea/docs/dep/air/approvals/bactcmb.pdf, accessed 7/10/14

- Proposed CO firing gas from the CTG of 5.0 ppmvd at 15% O2 during operation during operation at 50% load or lower, or during periods when operating load is changing significantly.

- Proposed VOC firing gas from the CTG of 3 ppmvd at 15% O2 during operation during operation at 50% load or lower, or during periods when operating load is changing significantly.

- Proposed NH3 firing gas from the CTG of 5.0 ppmvd at 15% O2 during operation during operation at 50% load or lower, or during periods when operating load is changing significantly.

When operating load is changing significantly the turbine controls automatically can transition out of dry-low-NOx (DLN) mode. MIT proposes that when the unit is not in DLN mode that a higher emission limit is needed.

Particulate Matter (PM) BACT

A complete BACT analysis addressing particulate matter (PM) emissions is available in the MCPA application. 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. 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.

The BACT analysis shows that post-combustion control is considered technically infeasible for this project. All available post-combustion controls (e.g. filters) 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.

The only remaining control technology in this analysis is the use of clean fuels and clean combustion. The effectiveness of this approach is summarized in Table C-7 below.

Table C-7 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.

Consistent with the analysis presented in the MCPA, 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.

Carbon Dioxide BACT

A complete BACT analysis addressing carbon dioxide (CO_2) emissions is available in the MCPA application. Carbon dioxide emissions are also addressed as greenhouse gas emissions per the MEPA GHG Policy and Protocol in Section C-5 of this document.

The BACT analysis shows that post-combustion control (carbon capture and sequestration) is considered technically infeasible for this project. Problems include lack of space for the required absorption and compression system, compressor noise, lack of a pipeline or other transportation system, and lack of a storage site.

The only remaining control technology is the use of clean fuels and clean combustion. Requested data is summarized in Table C-8 below.

Table C-8 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)	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.

Consistent with the analysis presented in the MCPA, 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.

Top-Case BACT for Cold-Start Engine

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources to document BACT for the cold-start engine. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Table C-9 below contains the MassDEP Top Case BACT Guideline for Emergency IC Engines equal to or greater than 37 kW.

Table C-9 Top-Case BACT from MassDEP Guidance for Emergency IC Engines

Source	Fuel	Air Contaminant	Emission Limitations	Control Technology
IC Engines equal to or greater than 37 kw (Emergency Engines)	ULSD (0.0015%)	NOx, PM, CO, VOC	Comply with applicable emission limitations set by US EPA for non-road engines at 40 CFR 89	N/A

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.

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 C-10 below compares the proposed limits for Boilers 7 and 9 compared to the relevant 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 C-10 Proposed Top-Case BACT for Boilers 7 and 9

Pollutant	Natural Gas		ULSD	
	Limit (lb/MMBTU)	BACT Guidance (lb/MMBTU)	Limit (lb/MMBTU)	BACT Guidance (lb/MMBTU)
CO	0.011*	0.011	0.035	0.035
NOx	0.011	0.011	0.1	0.1
PM10/PM2.5	0.01	0.01	0.03	0.03
SO2	0.0014	N/A	0.0016	N/A
VOC	0.03	0.03	0.03	0.03
CO2	119	N/A	166	N/A

* Boiler 9 has a CO limit of 0.033 lb/MMBtu at loads below 33%.

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.

C-3.5 Air Quality Impacts

As part of the MCPA and PSD air applications, MIT has documented that the proposed project will not lead to a condition of unhealthy air. This is done by using computer dispersion modeling, as described in this section. The key analysis documents that MAAQS and NAAQS will not be exceeded; separate analyses address air toxics and PSD increments.

MAAQS and NAAQS

EPA[5] describes NAAQS as follows:

> *"The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards... for pollutants considered harmful to public health and the environment. The Clean Air Act identifies two types of national ambient air quality standards. Primary standards provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings."*

[5] http://www.epa.gov/air/criteria.html, accessed April 2015.

Table C-11 shows the applicable NAAQS/MAAQS.

Table C-11 National and Massachusetts Ambient Air Quality Standards, SILS, & PSD Increments

Pollutant	Averaging Period	NAAQS/MAAQS ($\mu g/m^3$)	
		Primary	Secondary
NO_2	Annual (1)	100	Same
	1-hour (2)	188	None
SO_2	Annual (1)	80	None
	24-hour (3)	365	None
	3-hour (3)	None	1300
	1-hour (4)	196	None
$PM_{2.5}$	Annual (1)	12	15
	24-hour (5)	35	Same
PM_{10}	24-hour (6)	150	Same
CO	8-hour (3)	10,000	Same
	1-hour (3)	40,000	Same
Ozone	8-hour (7)	147	Same
Lead	3-month (1)	1.5	Same

(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

The facility cannot cause or contribute to the violation of any National or Massachusetts State Ambient Air Quality Standard (NAAQS or MAAQS). Air quality dispersion modeling is used to demonstrate compliance with these thresholds for NO_2, SO_2, $PM_{2.5}$, PM_{10}, and CO. The project does not directly emit ozone; project impacts to ambient ozone concentrations are minimized by applying BACT controls to ozone precursors (NO_x and VOC) as described in Section C-3.4 above. Lead emissions and impacts are negligible.

For the modeled pollutants, the compliance demonstration broadly uses the following steps:

- Identify which operating conditions cause the worst-case impact from the proposed new project equipment (for each pollutant and averaging time);
- For pollutants and averaging times where the project impacts are above Significant Impact Levels (SILs), identify significant nearby sources;
- Identify background (ambient) measured concentrations from nearby monitoring stations;

- Document that the combined impact of the new project sources, the existing CUP sources, the significant nearby sources (if applicable), and the background remain below the MAAQS/NAAQS for each pollutant and averaging time.

Modeling Methods

The U.S. EPA approved air quality model used for this analysis is AERMOD. 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.

The AERMOD model is the most appropriate for projecting impacts from the Project. It is a refined modeling technique per the EPA Guideline on Air Quality Models (40 CFR 51 Appendix W) and is the EPA-recommended model for this type of analysis. MassDEP guidance states that use of modeling platforms other than AERMOD must be approved by MassDEP and EPA. While any modeling technique will be less accurate in areas subject to major topographic influences that experience meteorological complexities, wind direction specific building parameters generated by the latest version of the EPA Building Profile Input Program (BPIP-Prime) were input into AERMOD to account for potential downwash from nearby structures in the dispersion calculations. Also, while a steady-state Gaussian plume model does not apply during calm conditions, AERMOD contains algorithms for dealing with low wind speed (near calm) conditions.

Project 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 of CPA Appendix D. Modeling for the turbines was performed over a range of loads and ambient temperatures to determine the case resulting in the highest air quality impact of each pollutant. 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 PM2.5 and PM10, the cooling towers are included in the modeling analysis.

Table C-12 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 C-12 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 C-13 and C-14 for 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 C-15.

Table C-13 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 (°K)	Emission Rate (g/s)	Fuel	Load Condition
SO_2	1-Hour	20.0	355.4	0.14	NG	Case I.a: 60° F, Turbine #2 100% Load, Duct Burner On
	3-Hour	20.0	355.4	0.14	NG	Case I.a: 60° F, Turbine #2 100% Load, Duct Burner On
	24-Hour	20.0	355.4	0.14	NG	Case I.a: 60° F, Turbine #1 100% Load, Duct Burner On
	Annual	17.7	355.4	0.14[1]	NG	Case I.Annual: 60° F, Turbine #1, 75% Load, Duct Burner On

Table C-13 New Turbine Source Characteristics and Emission Rates for 1 Turbine with Duct Burner/HRSG (Operational Scenario 1) (Continued)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (°K)	Emission Rate (g/s)	Fuel	Load Condition
NO_x	1-Hour	22.5	380.4	1.02	ULSD	Case I.g: 0° F, Turbine #2, 100% Load, Duct Burner On
	Annual	17.7	355.4	0.49[1]	NG	Case I.Annual: 60° F, Turbine #1 75% Load, Duct Burner On
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
CO	1-Hour	22.5	380.4	0.70	ULSD	Case I.g: 0° F, Turbine #2, 100% Load, Duct Burner On
	8-Hour	22.5	380.4	0.70	ULSD	Case I.g: 0° F, Turbine #1, 100% Load, Duct Burner On

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

Table C-14 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 (°K)	Emission Rate[1] (g/s)	Fuel	Load Condition[2]
SO_2	1-Hour	20.0	355.4	0.65	NG	Case 2.a: 60°F, Turbines 1&2, 100% Load, Duct Burner On
	3-Hour	20.0	355.4	0.65	NG	Case 2.a: 60°F, Turbines 1&2, 100% Load, Duct Burner On
	24-Hour	17.7	355.4	0.23	NG	Case 2.e: 60°F, Turbines 1&2, 75% Load, Duct Burner On
	Annual	17.7	355.4	0.27[3]	NG	Case 2.Annual, Turbines 1&2, 75% Load, Duct Burner On
NO_x	1-Hour	22.5	380.4	2.56	ULSD	Case 2.g: 0°F, Turbines 1&2, 100% Load, Duct Burner On
	Annual	17.7	355.4	0.99[3]	NG	Case 2.Annual, Turbines 1&2, 75% Load, Duct Burner On
PM_{10}	24-Hour	18.9	380.4	2.56	ULSD	Case 2.h: 0°F, Turbines 1&2, 75% Load, Duct Burner On

Table C-14 New Turbine Source Characteristics and Emission Rates for 2 Turbines with Duct Burners/HRSGs (Operational Scenario 2) (Continued)

Pollutant	Avg. Period	Exit Velocity. (m/s)	Exit Temp (°K)	Emission Rate[1] (g/s)	Fuel	Load Condition[2]
$PM_{2.5}$	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
CO	1-Hour	18.9	380.4	1.15	ULSD	Case 2.h: 0°F, Turbines 1&2, 75% Load, Duct Burner On
	8-Hour	22.5	380.4	1.41	ULSD	Case 2.g: 0°F, Turbines 1&2, 100% 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 C-15 New 2MW Cold Start Emergency Engine and Cooling Tower Source Characteristics and Emission Rates

Source	Averaging Time	Exit Temp (K)	Exit Velocity (m/s)	PM_{10}/ $PM_{2.5}$ (g/s)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)
2MW Cold Start Emergency Engine	Short-Term	672.7	18.15	1.68E-2[1]	3.65E-3	0.151[2]	0.277
	Annual[3]			1.76E-3	1.26E-4	0.151	N/A
Cooling Towers #11, 12, 13 per cell (6)	N/A	298.7	8.0	4.40E-3	N/A	N/A	N/A

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

2 This emission rate is scaled by the permitted hours of operation per EPA Guidance. (http://www.epa.gov/nsr/documents/20100629no2guidance.pdf)

3 Annualized emissions assuming a maximum of 300 hours per year.

Existing Source Data

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 C-16, C-17 and C-18.

Table C-16 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
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 C-17 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
NO_2	Short-term	Boiler #9 alone full load	Full load	Full load
	Annual	Boiler #9 alone full load	Full load	Full load
SO_2	Short-term	Boiler #7 and #9	Full load	Full load
	Annual	Boiler #9 alone full load	Minimum Load	Full load
CO	Short-term	Boiler #7 and #9	Full load	Full load

Table C-18 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)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)
Boilers 7 & 9	Boilers 7 & 9 (full load)	Short-Term	473.7	17.68	0.83	0.83	4.16E-2	2.09	0.97
		Annual			-	0.29	4.16E-2	0.35	-
	Boiler 9 only (full load)	Short-Term	430.4	8.06	0.45	0.45	2.27E-2	1.50	0.53
		Annual			-	0.164	2.27E-2	0.20	-
Boilers 3,4,5	Full Load	Short-Term	430.4	5.91	2.62	2.62	7.18E-2	14.27	1.90
		Annual			-	1.45	7.18E-2	9.61	-
	Minimum Load	Short-Term	405.4	0.73	0.32	0.32	8.82E-3	1.76	0.23
		Annual			-	0.179	8.82E-3	1.18	-
Turbine #1	Full Load	Short-Term	405.4	35.79	1.756	1.756	5.92E-2	5.87	0.88
		Annual			-	0.63	5.92E-2	3.13	-
Generator	Full Load	Short-Term	790.3	61.94	9.58E-2	9.58E-2	4.03E-3	0.15	0.28
		Annual			-	3.28E-3	1.39E-4	0.15	N/A
Cooling Tower 1 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3	N/A	N/A	N/A
Cooling Tower 2 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3	N/A	N/A	N/A
Cooling Tower 3 per cell (2)	N/A	N/A	298.7	8.0	5.86E-3	5.86E-3	N/A	N/A	N/A
Cooling Tower 4 per cell (2)	N/A	N/A	298.7	8.0	5.18E-3	5.18E-3	N/A	N/A	N/A
Cooling Tower 5	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3	N/A	N/A	N/A
Cooling Tower 6	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3	N/A	N/A	N/A
Cooling Tower 7 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3	N/A	N/A	N/A
Cooling Tower 8 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3	N/A	N/A	N/A
Cooling Tower 9 per cell (4)	N/A	N/A	298.7	8.0	2.65E-3	2.65E-3	N/A	N/A	N/A
Cooling Tower 10 per cell (2)	N/A		298.7	8.0	4.40E-3	4.40E-3	N/A	N/A	N/A

[1] This emission rate is scaled by the permitted hours of operation per EPA Guidance. (http://www.epa.gov/nsr/documents/20100629no2guidance.pdf)

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 and MAAQS. 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. Data is also available via the EPA website (http://www.epa.gov/airquality/airdata) and was used for the 3-hour and 24-hour SO_2 averages since these are no longer included in the published monitor reports. 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. All pollutants are monitored at Kenmore Square, i.e., SO_2, CO, NO_2, PM_{10}, and $PM_{2.5}$. A summary of the background air quality concentrations based on the 2012-2014 data are presented in Table C-19. 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 C-19 Observed Ambient Air Quality Concentrations and Selected Background Levels

Pollutant	Averaging Period	2012	2013	2014	Background Level	NAAQS
SO_2 ($\mu g/m^3$)	1-hour	13.2	31.4	25.4	23.3	196
	3-Hour[a]	27.8*	36.4*	24.6*	36.4	1,300
	24-Hour[b]	14.1	15.7*	13.1*	15.7	365
	Annual	4.9	2.6	2.5	4.9	80
CO ($\mu g/m^3$)	1-Hour	1489.8	1489.8	1962.4	1962.4	40,000
	8-Hour	1031.4	1031.4	1260.2	1260.2	10,000
NO_2 ($\mu g/m^3$)	Annual	33.5	33.5	32.3	33.1	100
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[c]	9.0	8.0	6.0	7.7	12

Notes:

* (conversion factors of 1 ppm = 2620 $\mu g/m^3$ SO_2; = 1146 $\mu g/m^3$ CO; and 1882 $\mu g/m^3$ NO_2 used).

* data obtained from EPA at http://www.epa.gov/airquality/airdata;

[a] Background level for 3-hr SO_2 is the highest-second-high SO_2 value (obtained from EPA website).

[b] Background level for 24-hr SO_2 and PM_{10} is based on the highest-second-high value.

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

National Ambient Air Quality Standards 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, the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. For those pollutants and averaging periods with Project impacts above the SILs, cumulative source modeling was conducted.

AERMOD modeling was performed for the pollutants and averaging periods which had Project impacts below the SILs. The new MIT sources were modeled with the existing MIT sources; then the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. For Operational Scenario 1 when only one new turbine is in operation, the existing turbine is still operating. The existing turbine will be shut down once two new turbines are in operation (Scenario 2). For Scenario 2, the flues for the two new turbines are merged and modeled with an effective diameter of 9.9 ft. Table C-20 presents the criteria pollutant concentrations compared to the NAAQS for each operating scenario. The total concentration (modeled plus background) are below the NAAQS for all pollutants.

Table C-20 AERMOD Model Results for the Full MIT Facility for Operational Scenarios 1 & 2 Compared to the NAAQS[1]

Poll.	Avg. Period	Form	AERMOD Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	NAAQS (μg/m3)	% of NAAQS	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 1 (1 new turbine/HRSG)									
SO_2	1-hr[(2)]	H4H	3.2	23.3	26.5	196	14%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr.	H2H	2.8	36.4	39.2	1300	3%	8/12/14 hr 18	327500.08, 4692162.84, 2.73
	24-hr.	H2H	1.8	15.7	17.5	365	5%	12/21/10 hr 24	327550.08, 4692062.84, 2.73
	Annual	H	0.29	4.9	5.2	80	6%	2010	327550.08, 4692062.84, 2.73
CO	1-hr.	H2H	62.1	1962.4	2024.5	40000	5%	5/26/11 hr 12	327500.08, 4692212.84, 2.73
	8-hr	H2H	42.9	1260.2	1303.1	10000	13%	9/18/12 hr 16	327500.08, 4692162.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)									
SO_2	1-hr[(2)]	H4H	3.3	23.3	26.6	196	14%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr	H2H	2.7	36.4	39.1	1300	3%	8/12/14 hr 18	327500.08, 4692162.84, 2.73
	24-hr	H2H	1.15	15.7	17.0	365	5%	12/23/10 hr 24	327550.08, 4692062.84, 2.73
	Annual	H	0.23	4.9	5.1	80	6%	2010	327550.08, 4692062.84, 2.73
CO	1-hr.	H2H	52.4	1962.4	2014.8	40000	5%	5/26/11 hr 12	327500.08, 4692212.84, 2.73
	8-hr	H2H	40.1	1260.2	1300.3	10000	13%	1/24/14 hr 16	327550.08, 4692062.84, 2.73

[1] PM_{10} 24-hr, $PM_{2.5}$ 24-hr, $PM_{2.5}$ Annual, NO_2 1-hr, NO_2 Annual impacts from MIT are reported in Table D-17

[2] High 4th High (99th%) maximum daily 1-hr concentration averaged over 5 years.

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 $PM_{2.5}$, 24-hr PM_{10} and 1-hr and annual NO_2 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 $PM_{2.5}$, PM_{10} or NO_2 emission rates (>10 tpy $PM_{2.5}$, >15 tpy PM_{10} or >40 tpy NO_2 based on reported actual emissions). Four nearby facilities have been identified satisfying the criteria for PM_{10} and $PM_{2.5}$. Two additional sources were identified satisfying the criteria for NO_2. 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)
5. (NO_2 Only) Logan Airport (~5.9 km to the east-northeast of the MIT CUP)
6. (NO_2 Only) Kneeland Street (~3.2 km to the east-southeast of the MIT Cup)

Cumulative AERMOD modeling was conducted for each of the MIT CoGen Project Operating Scenarios with predicted impacts above the SILs. The results of the cumulative source air quality modeling are presented in Table C-21. 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 C-21 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) (UTME, UTMN, Elev.)
				MIT	Kendall Station	Harvard Blackstone	MATEP	Mystic Station	Kneeland Street	Logan Airport					
Operational Scenario 1 (1 new turbine/HRSG)															
PM_{10}	24-hr	H6H	85.7	0.045	32.4	0.23	0.0020	0.018	N/A	N/A	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	N/A	N/A	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	N/A	N/A	7.7	12	90.8%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr[(1)]	H8H	143.7	66.8	0.010	0.0083	0.14	0.025	0.015	0.047	76.7	188	76.4%	2010-2014	327500.0, 4692212.84, 2.73
	Annual[(2)]	H	46.7	9.38	1.03	0.99	0.77	0.61	0.47	0.25	33.1	100	46.7%	2010	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	N/A	N/A	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	N/A	N/A	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	N/A	N/A	7.7	12	87.8%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr[(1)]	H8H	139.8	55.14	0.15	0.12	0.070	0.038	0.052	0.034	84.2	188	74.4%	2010-2014	327550.08, 4692062.84, 2.73
	Annual[(2)]	H	46.2	8.92	1.04	1.06	0.78	0.61	0.48	0.25	33.1	100	46.2%	2010	327550.08, 4692062.84, 2.73

[1] High 8th High (98th%) maximum daily 1-hr concentration averaged over 5 years with seasonal/diurnal background; PVMRM used for conversion of NOx to NO_2.
[2] Annual NO_2 uses ARM for NOx to NO_2 conversion of 0.75 per EPA Guidance. http://www.epa.gov/scram001/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

PSD Increment Modeling

The MIT CoGen Project is a major modification of an existing major source, subject to the requirement to obtain a PSD permit. Beyond the MAAQS/NAAQS modeling presented above, PSD increment modeling is required for fine particulate (PM10 and PM2.5). 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 credit for increment expanding sources (those that have added controls or stopped operating) after the PSD baseline date.

For the PSD increment modeling, new project sources are 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) are modeled at their maximum actual emission rates (using a negative emission rate in AERMOD). Since the baseline has not been previously established for PM2.5, there are no other PM2.5 increment-consuming sources in the baseline area to include in the PSD Increment Modeling. However, for PM10 the baseline has been established and the following sources are included as increment consuming: GenOn Kendall Station, Harvard Blackstone, MATEP, and Mystic Generating Station.

The results in the Appendix D of the PSD application shows that applicable PSD increments are not exceeded at any receptor for any MIT CoGen operating scenario.

Non-Criteria Pollutant Modeling

In addition to the MAAQS/NAAQS analysis, an air quality impact assessment of the non-criteria pollutants emitted from the proposed combustion sources (two new turbines and 2 MW cold start emergency engine) was conducted. EPA AP-42 and California Air Toxics Emission Factor (CATEF) emission factors were used to derive the emission rates. The highest 24-hr and annual normalized AERMOD predicted concentrations were used, and then scaled by the pollutant emission rate to obtain the predicted concentration of each pollutant. The results in the Appendix D of the MCPA application present the worst-case predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has an annual Allowable Ambient Limit (AAL) or a 24-hour Threshold Effects Exposure Limit (TEL). The results show that air quality impacts from the non-criteria emissions are well below the threshold levels of the corresponding MassDEP AALs and TELs.

C-4 Noise

C-4.1 Summary of MCPA Noise Analysis

The MCPA Noise Analysis (Appendix E of the MCPA) was performed by Acentech. The noise analysis provides a description of the applicable noise regulatory requirements, a brief explanation of noise terminology, a summary of the results of a complete ambient sound level monitoring program, and a discussion of the sound level modeling analysis for operation of the new CoGen installation.

The results of the sound level assessment in context of the MassDEP Noise Policy are provided below in Sections C-4.2 and C-4.3. In addition to these results, the Acentech report provides a thorough explanation of environmental noise metrics and sound level measurement methodology. It also describes measurement methods and results establishing background sound levels for comparison to proposed conditions. In brief, there are several ways in which sound (noise) levels are measured and quantified, each of which uses the logarithmic decibel ("dB") scale. An understanding of the effects of equipment sound on the human ear requires "A-weighted" sound level data ("dBA"), while the design of noise control treatments requires octave-band frequency data.

Acentech collected short-term ambient sound measurements and observations at six locations on Friday and Saturday nights (8-9 August and 9-10 August 2014). Consistent with technical instructions provided by MassDEP, short-term (20-minute) A-weighted broadband and one-third octave band sound level measurements were collected at each location at a height of approximately five feet (1.5 meters) above the ground, under low wind conditions, and during periods with no precipitation. Established background sound levels at each measurement location are provided below in Table C-22. Measurement locations are shown on Figure C-2.

Aerial Photograph Showing Planned Location for MIT CHP Addition and Distances to Property Line (PL) and Residential (R) Locations for August 2014 Ambient Sound Survey and Analysis.

Six short-term measurement locations and one long-term measurement location (marked by *); ambient sound measured at long-term Location R-1A is representative of sound at Location R-1.

Location	Approximate Distance from Project Center (ft)
PL-1 (North)	70
PL-2 (Northeast)	650
PL-3 (Southwest)	650
R-1 (Newtowne Ct. Apts.)	580
R-2 (MIT Housing)	1200
R-3 (MIT Housing)	1100

N

Acentech

MIT Cogeneration Project Cambridge, Massachusetts

Epsilon ASSOCIATES INC.

Figure C-2
Noise Measurement Locations

C-4.2 Consistency with Noise Policy

MassDEP Regulatory Context

MassDEP has the authority to regulate noise under 310 CMR 7.10, which is part of the Commonwealth's air pollution control regulations. Under the DEP regulations, noise is considered to be an air contaminant and, thus, 310 CMR 7.10 prohibits "unnecessary emissions" of noise.

MassDEP administers this regulation through Noise Policy DAQC 90-001 dated February 1, 1990. The policy limits new noise-generating equipment to a 10-dBA increase in the ambient sound measured (L90) at the property line and at the nearest residences. For developed areas, the DEP has utilized a "waiver provision" at the property line in certain cases. This is appropriate when are there are no noise-sensitive land uses at the property line and the adjacent property owner agrees to waive the 10-dBA limit. The residences nearest to the MATEP facility include multi-family residences on Francis Street, the nearest of which is approximately 300 feet away, and a new multi-family building being built at the site of the former Massachusetts Mental Health Center, approximately 150 feet away.

The ambient level is defined as the background A-weighted sound level that is exceeded 90% of the time (L90), measured during equipment operating hours. For new noise-generating equipment which will or could operate 24-hours per day, the ambient level typically occurs during the quietest nighttime period (midnight to 4 a.m.).

The MassDEP policy further prohibits "pure tone" conditions where one octave-band frequency is 3 dB or more greater than an adjacent frequency band. An example of a "pure tone" is a fan with a bad bearing that is producing an objectionable squealing sound.

City of Cambridge Noise Requirements

The City of Cambridge has its own noise requirements set forth in Title 8, Chapter 8.16, Noise Control of the City of Cambridge Code of Ordinances. Due to the project's location in Cambridge, MA, it is subject to these noise requirements as well as the MassDEP requirements set forth above. The standards are enforced only for the source sound levels as a project owner has no control over ambient sound levels. The cogeneration facility will be operated continuously and thus must address the more stringent nighttime noise standards for the nearest residential and commercial receptors in the surrounding area. The noise standards can be found in Table C-22 below.

Table C-22 City Of Cambridge Zoning District Noise Standards (ref: Table 8.16.060E)

Maximum Allowable Octave Band Sound Pressure Levels (dB)

Octave Band Center Frequency (Hz)	Residential Area		Residential in Industrial		Commercial Area	Industry Area
	Daytime	Other Times	Daytime	Other Times	Anytime	Anytime
31.5	76	68	79	72	79	83
63	75	67	78	71	78	82
125	69	61	73	65	73	77
250	62	52	68	57	68	73
500	56	46	62	51	62	67
1,000	50	40	56	45	56	61
2,000	45	33	51	39	51	57
4,000	40	28	47	34	47	53
8,000	38	26	44	32	44	50

Single Number (dBA)

Equivalent (dBA)	60	50	65	55	65	70

Results

The sound emissions from the entire CHP Project, which includes the combustion turbine generator packages, heat recovery steam generators, fuel gas compressors, chillers, new cooling towers, cold start generator, support equipment, and cogeneration building, will be specified and designed to address compliance with the MassDEP noise guidelines and City of Cambridge Noise Standards. The tables below present the sound estimates for the CHP addition at the nearest property line and residential locations. As noted below the table, the estimates at the nearest location (PL-1) are based on sound levels measured on the existing new cooling tower, information provided on the CHP equipment and building layout, recommended noise specification values, and the expected building design to meet the overall project sound criteria. The estimates at the other five more distant property line and community residential locations are based on the PL-1 levels with attenuation to account for distance (i.e., hemi-spherical spreading), but with no additional attenuation associated with other factors, such as shielding by intervening buildings, air absorption, or anomalous excess attenuation.

The results of the sound level modeling for the CHP project are presented in Table C-23 below. These results are extracted from the Acentech Noise Report and represent the modeling at Property Line points (PL) and Residential points (R).

Table C-23 Sound Level Modeling Results Summary Table

Location	Measured Background Sound Level	Modeled Project-Only Sound Level	Combined Project + Background Sound Level	Increase Over Background	Meets MassDEP Noise Policy?
	dBA	dBA	dBA	dBA	
PL-1	61	62	64	3	YES
PL-2	59	43	59	0	YES
PL-3	63	43	63	0	YES
R-1	58	44	58	0	YES
R-2	57	37	57	0	YES
R-3	56	38	56	0	YES

For purposes of evaluating the DEP noise policy, future worst-case sound levels would arise by combining the contribution from the Project with the quietest nighttime background sound levels. These totals and their increases are shown in Table C-23 above. The increase over background at the nearest receptors during these nighttime conditions is expected to range from 0 dBA to 3 dBA, within the relevant DEP policy limit of 10 dBA. The results can be broken down to be considered at individual octave bands as well. These results can be found in Table C-24 below.

Table C-24 Estimates of Project-Only Sound Pressure Levels and Overall A-Weighted Sound Levels

	Octave Band Center Frequency (Hz)								
Location	31.5	63	125	250	500	1000	2000	4000	8000
PL-1	76	75	70	65	59	53	48	44	41
PL-2	57	56	51	46	40	34	29	25	22
Pl-3	57	56	51	46	40	34	29	25	22
R-1	58	57	52	47	41	35	30	26	23
R-2	51	50	45	40	34	28	23	19	16
R-3	52	51	46	41	35	29	24	20	17

Notes:

1. All data rounded to nearest whole decibel.

C-4.3 Avoidance, Minimization, and Mitigation

Noise levels from the Project at each of the modeled noise-sensitive receptors, taking into account attenuation due to distance, structures, and noise control measures, are predicted to remain below 10 dBA during even the quietest nighttime hours and will comply with all MassDEP A-weighted and "pure tone" noise limits.

The sound emissions from the entire CHP addition, which includes the combustion turbine generator packages, heat recovery steam generators, fuel gas compressors, chillers, new cooling towers, cold start generator, support equipment, and new building, will be specified, designed, and operated to address compliance with the MassDEP Noise Criteria and the City of Cambridge Noise Standards. Abatement methods to be employed to control the sound of the CHP addition will include the following:

- Combustion turbine generator sets will be installed in sound-attenuated enclosures.
- Majority of cogeneration equipment will be installed in an acoustically-designed building with appropriate treatments for building ventilation systems and access openings.
- Mufflers will be installed as necessary on the gas turbine air intake, gas exhaust, and turbine enclosure ventilation systems.
- Mufflers will be installed as needed on non-emergency steam vents.
- Reduced-noise lube oil cooler model will be used or sound barrier walls will be installed for the standard model as needed
- The fuel gas compressor and drive motor will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.
- The cold start diesel generator will be installed in a sound- attenuated enclosure located on the roof with treated ventilation air paths.
- New mechanical draft wet cooling towers will include reduced-noise fans with variable frequency drives and louvered barrier walls as required to meet sound ordinance.

The major CHP equipment will be located within the southern section of the building toward the existing railroad tracks and other support systems and administrative spaces will be located on the northern section of the building toward Albany Street. As noted above, the CTG will be enclosed and located within the new building and the fuel gas compressor and cold start diesel generator will be installed in sound-attenuated enclosures located on the roof with treated ventilation air paths. The average sound levels around the enclosed CTG and the balance of the CHP area are estimated to be 85 dBA or less. The building walls and roof will have a minimum surface weight of 8 psf or a composite structure that can provide a minimum Sound Transmission Class (STC) rating of STC 30. The equipment and building air ventilation paths will include treatments (e.g., mufflers, lined ducts, acoustic louvers, and local barriers) with suitable sound attenuation; and the major ventilation openings will be on the south wall of the building facing the railroad tracks and shielded from direct line-of-sight to the community. The personnel doors and overhead doors that directly access the main CHP room from outdoors will be specified with an appropriate STC rating. The overall design and construction of the building shell will aim to achieve 55 to 60 dBA directly outside the building walls facing the community.

C-5 GHG

This section addresses GHG emissions generated by the project and options that may reduce those emissions in accordance with the MEPA Greenhouse Gas Emissions Policy and Protocol (GHG Policy). The GHG Policy requires that certain projects undergoing review by the MEPA Office quantify the project's GHG emissions and identify measures to avoid, minimize, or mitigate such emissions. In addition to quantifying project-related GHG emissions, the GHG Policy also requires proponents to quantify the impact of proposed mitigation in terms of energy savings and GHG emissions.

The analysis provided herein focuses on emissions of carbon dioxide (CO_2). As noted in the GHG Policy, there are other GHGs, but CO_2 is the predominant contributor to global warming. Furthermore, CO_2 is by far the predominant GHG emitted from the types of sources related to projects subject to the Policy, and CO_2 emissions can be calculated for these source types with readily available data.

C-5.1 GHG Policy Summary

The GHG Policy requires the Proponent to calculate and compare the GHG emissions in two cases, and then consider other mitigation.

Case 1 is the baseline from which change in energy use and GHG emissions reductions are measured.

Case 2 represents the proposed project, including measures incorporated to reduce GHG emissions.

Other Mitigation. In addition to these two cases, the Policy requires that all feasible mitigation measures that could reduce GHG emissions be considered.

For quantifying emissions, the GHG Policy focuses on three categories: building-related stationary source emissions; process-related stationary source emissions; and indirect emissions from transportation. Of these, the MIT Central Utilities Plant Second Century Project (the Project) nearly exclusively involves process-related stationary source emissions. The Project will have direct emissions from fuel consumption and indirect emissions from electricity/energy consumption, as distinct from emissions associated with project buildings.

The proposed project consists of the extension of an existing building with a footprint of approximately 26,500 square feet and 63′ above ground level (AGL) tall with three 165′ AGL high flues centrally co-located in a common stack structure. The new space will predominantly house the energy generation and support equipment and will not be subject to the same HVAC demands as typical office, commercial, or residential space. The building extension will comply with Cambridge building code requirements, including compliance with stretch code. No significant new water use or wastewater generation is proposed, and no net new traffic trips are expected.

C-5.2 Identifying Baseline & Proposed Cases

The GHG Policy provides the following guidance for identifying the baseline case:

> *establish a project baseline for the industrial component of the project by estimating the amount of fuel or electricity to be consumed by the specific processes without any mitigation measures (sometimes referred to as the "business as usual" scenario). The intent of this calculation is to estimate emissions from GHG-intensive industrial processes such as power plants, energy-intensive manufacturing processes, or other industrial processes, in order to provide a better understanding of overall project emissions.*

And the following guidance for the proposed case:

> *calculate emissions reductions associated with upgrading the efficiency of industrial processes (by calculating reduced fuel or electricity consumption).*

The "business as usual" scenario would be the separate generation of electricity and thermal energy. This choice of baseline is consistent with MassDEP and EPA precedent. Specifically, the MassDEP Environmental Results Program (ERP) regulations "encourage the installation of Combined Heat and Power (CHP) systems" by establishing "a methodology that enables the applicant to…take into account emissions that will not be created by omitting a conventional separate system (e.g., boiler) to generate the same thermal output." (quote from 2008 regulatory proposal). The EPA Energy Star CHP Award is for "fuel and emissions savings over comparable, state-of-the-art separate heat and power generation."

The proposed case is consistent with the air plan approval application and includes the turbine and duct burner. Emissions in the proposed case are calculated based on full-load, year-round operation firing natural gas; this is consistent with the use of a natural gas-fired boiler in the baseline case. Although the project will have backup ULSD firing, the ULSD would be used in situations where a boiler would also be firing ULSD. Keeping both the baseline and proposed cases as gas-only allows a consistent comparison.

The calculation conservatively does not take credit for the fact that the duct burner will be more efficient than a similarly-sized boiler, because the combustion air is preheated.

C-5.3 Quantifying Emissions

The GHG Policy has the following guidance for quantifying GHG emissions:

> *In order to quantify direct emissions, the proponent should estimate fuel consumption associated with industrial processes and then derive the approximate CO2 emissions by using a reliable data source that contains emission factors for CO2 based on fuel type. To quantify indirect emissions, the proponent should estimate the amount of electricity to be consumed by the industrial processes and then multiply total purchased electricity usage by an emissions factor that calculates the CO2 emitted through the generation of electricity.*

The emission factors used in the GHG calculations are:

- 117 pounds of CO2 per million BTU of natural gas used, consistent with US Energy Information Administration national average;
- 941 pounds of CO2 per megawatt hour electricity generated, the current Marginal Emission Factor for the ISO -NE Grid (2014 draft) as provided in example DOER calculations for analysis of CHP as discussed in Section C-5.8; and
- 726 pounds of CO2 per megawatt hour electricity generated, the current Annual Average Emission Factor for the ISO -NE Grid (2014 draft) for calculation of balance-of-plant GHG savings per the GHG Policy.

C-5.4 Other Mitigation

To identify all feasible mitigation measures that could reduce GHG emissions, MIT considered the following:

- Renewable energy generation: The use of solar photovoltaic (or solar hot water) is precluded by the lack of available roof or ground space for solar panels at the CUP. MIT continues separate efforts to incorporate solar energy elsewhere on campus. Similarly, there is no feasible location for a wind turbine or a ground source heat pump system.
- Selection of a different CHP technology: For a project of this size, a combustion turbine is more efficient and cost-effective than other technologies such as fuel cells. Gas engines were discounted due to the electric power and steam production needs being considered. The engines had higher emissions and a larger footprint. While the electrical efficiency is higher, the overall plant efficiency is lower because MIT does not have a reasonable use for thermal energy from low grade jacket water produced by the engine.

- Selection of a different combustion turbine: As discussed in Section C-5.5 below, the turbine options selected are the most efficient available to meet the identified project need. Turbine selection has not been finalized.

- Minimization of parasitic loads: As discussed in Section C-5.6 below, MIT will minimize loads to the extent technically and economically feasible.

C-5.5 Minimize GHG Emissions: Turbine Selection

When identifying candidate turbines for the Project, MIT reviewed options based on four general criteria:

- Ability to meet the needs of the MIT campus for capacity and reliability;

- First cost and long-term operating cost;

- Ease of integration into existing facility; and

- Ability to supply electric and thermal energy efficiently and cost-effectively.

MIT has not made a final turbine selection. The air plans application uses as its basis the GE LM2500 turbine; MIT will also evaluate other commercially available CTGs during the procurement process. While there is some variability in the electric generation efficiency of the combustion turbines available for this project, electrical generation efficiency is only one element of a properly-designed CHP system. The overall CHP project efficiency is for the combination of electric power and thermal heat; if less energy is converted to electricity, more energy is available for heat. A well-designed CHP system is well matched to the electric and thermal loads it is serving.

Turbine manufacturers add and modify turbine models over time. If by the time the turbine order is being placed, a new or modified turbine model is usually available, and that turbine meets the descriptions in the MassDEP application and MEPA review processes, MIT will consider the new turbine model. Final selection will be made by MIT considering environmental, logistical, and economic factors.

The thermal efficiency of the Heat Recovery Steam Generator (HRSG) will be significantly higher than for an equivalent stand-alone boiler. MIT expects a 95% thermal efficiency in the final design. The thermal efficiency of the final design will be a function of space constraints, the mechanical and structural considerations involved in integrating the HRSG with the rest of MIT's steam generation and supply equipment, catalyst placement requirements, etc.

C-5.6 Minimize GHG Emissions: Balance of Plant

Balance of Plant project elements include design of the HRSG, implementation of turbine support systems such as inlet air cooling/heating, and parasitic loads. Parasitic loads are electrical loads associated with the generating equipment that decrease the net electrical output of the system. These are typically support equipment necessary for plant operation.

Much of the support equipment for the Project is in place at MIT (transformers, switchgear, cooling equipment, etc.). MIT has identified the following balance of plant elements where energy savings are possible:

1) Fuel Gas Compressors: The turbines need high-pressure natural gas for efficient operation. The compressor can be fitted with a variable frequency drive (VFD) to increase efficiency at part load. If significant part load operation is expected, 10% to 20% efficiency gain is possible. For this application, the estimated maximum load is 500 kW, minimum load is 30 kW, and average load is 60 kW. Using a VFD for this load will save an estimated 52.5 MWH per year (19 tpy CO2 savings). *MIT proposes to use a VFD fuel gas compressor.*

2) Combustion Air Cooling: Combustion turbines are more efficient with denser, colder air. Combustion air cooling only occurs on warmer days when additional electric generation is needed. The additional electricity generated by lower temperature inlet air exceeds the parasitic power of the chillers. The incremental electricity generated by the turbines will likely be lower-emitting than other grid generators called to meet the increased demand. For this application, chilled water from the existing chilled water system would be used to reduce the combustion air temperature to 60°F. This includes sensible and latent cooling. This can result in a net GHG savings in some conditions. Project design has not progressed to the point where specific energy savings can be identified. *MIT proposes to use combustion air cooling in situations where the additional generation provides environmental or reliability benefits.*

3) Chilled Water Free Cooling (Combustion Air Heating): During cold weather conditions (below 35F), the turbine can be operated more efficiently with warmer combustion inlet air. This is true because warmer inlet air allows better load management on the turbine; the heat rate can be improved at part load. Other advantages include improved SCR performance and better overall cycle performance, which reduces water and chemical consumption. Rather than using electric heaters, the project can use the Combustion Air Cooling coils to chill the Campus Chilled Water System while simultaneously increasing the inlet air temperature. There is a possible annual savings of 4.8 MWH based on avoided cooling tower fan energy to provide the same cooling (2 tpy CO2 savings). *MIT proposes to use chilled water free cooling in situations where it provides environmental or reliability benefits.*

4) Turbine Enclosure Support Systems: Fans and pumps are required to maintain the turbine operation. High-efficiency motors could provide some marginal energy use reductions in fans and pumps, and VFDs could provide some energy savings for motors serving variable loads. Project design has not progressed to the point where specific energy savings can be identified. *MIT will consider high-efficiency motors and VFDs (for motors serving variable loads) in the final project design.*

5) Urea vaporization: The SCR uses ammonia for air pollution control; MIT will transport and store urea, a safer material to transport and store, vaporizing that urea to generate ammonia as it is needed. Rather than relying solely on electric heaters, available heating can be used to preheat urea, lowering the overall electric load to heat the urea to vaporization. The heat source can be flue gas, steam, or a combination. There is a possible annual savings of 23.5 MWH associated with using waste heat to assist in vaporization (8.5 tpy CO2 savings). *MIT proposes to use waste heat to assist in urea vaporization.*

6) Compressed air drying: Compressed air is needed in the CUP for instrument air and other uses. Moisture must be removed from the compressed air for freeze protection and to avoid fouling instruments. Typically, a desiccant is used to dry the compressed air, and that desiccant material is regenerated by driving the moisture off with an electric heater. Instead, a heat of compression dryer ("MD" model rotary drum adsorption dryer or equivalent) uses compressor waste heat to efficiently separate the water. There is a possible annual savings of 0.98 MWH associated with using an adsorption dryer instead of a desiccant dryer with electric heat regeneration (0.4 tpy CO2 savings). *MIT proposes to use a heat of compression (adsorption rotary drum) dryer associated with the compressed air system.*

7) Medium Temperature Hot Water: Additional surface area can be built into HRSG for heat recovery that would serve a future medium temperature hot water system on campus. Such a (future) system could be used for heating dormitories or other spaces, using energy that would otherwise be wasted. This future enhancement would reduce overall fuel used to generate additional steam for an energy transfer station. *MIT proposes to construct the HRSG with the surface area and piping required to implement a Medium Temperature Hot Water system at a future date. Installation of the piping loops, etc. to distribute medium temperature hot water is not part of this project.*

8) Building Energy Use: The building expansion will include only a nominal amount of conditioned space, with the remainder of the building housing power generation and support equipment. Heating of the conditioned spaces will be done using waste heat from flash steam within the plant. Cooling will be accomplished only to the extent necessary for personnel and equipment. Although there is relatively little opportunity to save energy from heating and cooling, any opportunity will be maximized. MIT has identified lighting in the building expansion as an opportunity to save energy. *MIT proposes to use LED and occupancy lighting system to reduce energy use in the building expansion.*

C-5.7 Concurrent Facility Upgrades

As part of ongoing improvements in the operations at the MIT campus, several upgrade projects are being reviewed for the same time frame as the Project that will serve to improve the overall energy efficiency of MIT's operations. These include:

- Heat recovery for use in heating campus dormitories through medium temperature hot water system. At the conceptual stage, medium temperature hot water can be used to heat buildings in colder months, alternatively producing chilled water when there's excess hot water. MIT is designing the project to support this as a future addition, as part of the overall existing utilities master plan.
- Automation of the chilled water system to maximize overall efficiency.
- Blow down heat recovery for new Heat Recovery Steam Generators
- Capture of rain water for use in cooling tower make up, reducing use from city water system.
- Improved cooling tower efficiency, reducing electrical power usage.
- Improved chilled water efficiency through high efficiency series counter flow chillers.
- Improved efficiency in compressed air to campus system for classroom and laboratories, to decrease overall campus energy consumption.

MIT is not in a position to commit to any of these specific measures, and none of them are part of the proposed project. However, the ongoing efforts to identify and implement energy savings measures will continue and are supported by the proposed project.

C-5.8 Available Energy Model Results

As part of the design evaluation process, MIT has performed a technical assessment that included an hour-by-hour model to show how the inclusion of the project would affect how MIT operates other electricity and steam generating equipment onsite, and how much electricity would be imported from the electric grid for use on campus. That model showed that in general, the operation of the project will minimize the use of the older boilers and reduce the electrical load on the Eversource feeders. This means that the project will generally reduce the usage of older, less efficient onsite steam generation, reduce the need for imported electricity, and create more thermal energy through efficient cogeneration.

A summary spreadsheet is attached (Attachment C-5.2) which follows a sample calculation provided by DOER and shows the annual results of the plant-wide analysis. These calculations predict that addition of the project to the MIT CUP will generate an expected actual 216,000 tons/year of CO2, whereas it will displace 110,700 tons/year of CO2 from conventional steam generation and 136,900 tons/year of CO2 from the offsite generation of grid electricity. This equates to an 13% GHG reduction on a source energy basis. These results are based on expected annual average operations, based on a model of expected first year of full operation.

Table C-25 GHG Quantification

Expected Actual Project CO2 emissions, tons/year:	192,000
CO2 displaced from conventional useful heat system, tons/year:	104,000
CO2 displaced from grid electricity, tons/year:	113,000
Net Source CO2 Reduction, tons/year:	25,000
Net Source CO2 reduction, percentage	12%

C-5.9 Conclusions and Commitments

The project is an opportunity to provide more efficient and reliable energy to the MIT campus. Through the use of CHP, the project will improve MIT's energy efficiency, resulting in lower emissions of CO2 per unit of electricity, steam, and chilled water supplied. This analysis shows that the use of CHP provides a substantial GHG reduction of the "business as usual" case of separate electricity and steam production, and it further shows that MIT has selected appropriate equipment and operations to minimize the impact of CO2 emissions.

MIT commits to the following specific GHG reduction measures as part of the project:

- MIT will purchase and install a combustion turbine that fits the project description in this EENF and the related air plans application; final model selection will be made by MIT considering environmental, facility and equipment integration, and economic factors.
- MIT proposes to use VFD for the fuel gas compressor.
- MIT proposes to use combustion air cooling in situations where the additional generation provides environmental or reliability benefits.
- MIT proposes to use chilled water free cooling in situations where it provides environmental or reliability benefits.
- MIT will consider high-efficiency motors and VFDs (for motors serving variable loads) in the final project design.

- MIT proposes to use waste heat to assist in urea vaporization.
- MIT proposes to use a heat of compression (adsorption rotary drum) dryer associated with the compressed air system.
- MIT proposes to construct the HRSG with the surface area and piping required to implement a Medium Temperature Hot Water system. Installation of the piping loops, etc. to distribute medium temperature hot water is not part of this project.
- MIT proposes to use LED and occupancy lighting system to reduce energy use in the building expansion.
- MIT will submit a self-certification to the MEPA Office at the completion of the project. This certification will identify the GHG mitigation measures incorporated into the project and will illustrate the degree of GHG reductions from a Baseline case, as Baseline is defined herein, and how such reductions are achieved. Details of the MIT's implementation of operational measures will also be included.

C-6 Environmental Justice

C-6.1 Introduction

On February 11, 1994, then President Clinton issued Executive Order 12898, "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations."[6] This Executive Order was designed to ensure that each federal agency "make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations."

The assessment of environmental justice (EJ) considers the following:

- The areas in which the proposed Project may result in significant adverse environmental effects;
- The presence and characteristics of potentially affected minority and/or low-income populations ("communities of concern") residing in these study areas; and
- The extent to which these communities are disproportionately affected in comparison to the effects experienced by the population of the greater geographic area within which the affected area is located is determined.

---

[6] Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations. Available from U.S. Environmental Protection Agency (EPA) at http://www.epa.gov/fedreg/eo/eo12898.htm.

Guidance documents define minorities as including American Indian or Alaskan natives, Asian or Pacific Islanders, Black, or Hispanic persons. For the purposes of this analysis, a community may be considered to have a minority population when the percentage of minorities in a study area is "meaningfully greater" than the minority percentage of the general population.

A community of concern can also be similarly identified by the presence of low-income populations within the affected study area. The existence of these populations can be identified using the poverty thresholds available from the U.S. census and a comparison to the general population sets the context for the assessment. Poverty level is defined by the U.S. Census Bureau, which considers a variety of factors including family size, number of children and the age of the householder.

Massachusetts has established the *Environmental Justice Policy of the Executive Office of Environmental Affairs*. Per that policy, the MEPA office and MassDEP must enhance public participation opportunities for projects that potentially affect populations that are low-income, minority, foreign-born, or lack English proficiency.

Per Figure C-3, there are areas with minority populations and low-income populations in the vicinity of MIT. These areas were identified using the Massachusetts GIS online EJ mapping tool. Per the Massachusetts Office of Geographic Information[7]: "Polygons in the 2010 Environmental Justice (EJ) Populations layer represent areas across the state with high minority, non-English speaking, and/or low-income populations. Data in this layer were compiled for Census 2010 block groups from the 2010 census redistricting tables and from the American Community Survey (ACS) 2006-2010 5 year estimates tables."

C-6.2 Environmental Justice Analysis

The Project's 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."

[7] Accessed April 2015 and available at http://www.mass.gov/anf/research-and-tech/it-serv-and-support/application-serv/office-of-geographic-information-massgis/datalayers/cen2010ej.html.

The air quality dispersion modeling analysis conducted for the PSD application, provided on CD in Appendix A, documents that 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.

C-6.3 Enhanced Public Participation

Because MIT is within five miles of an Environmental Justice (EJ) community, filing an ENF triggers enhanced public participation.[8] The enhanced public participation typically involves noticing the public meeting in alternative language newspapers and providing translation services.

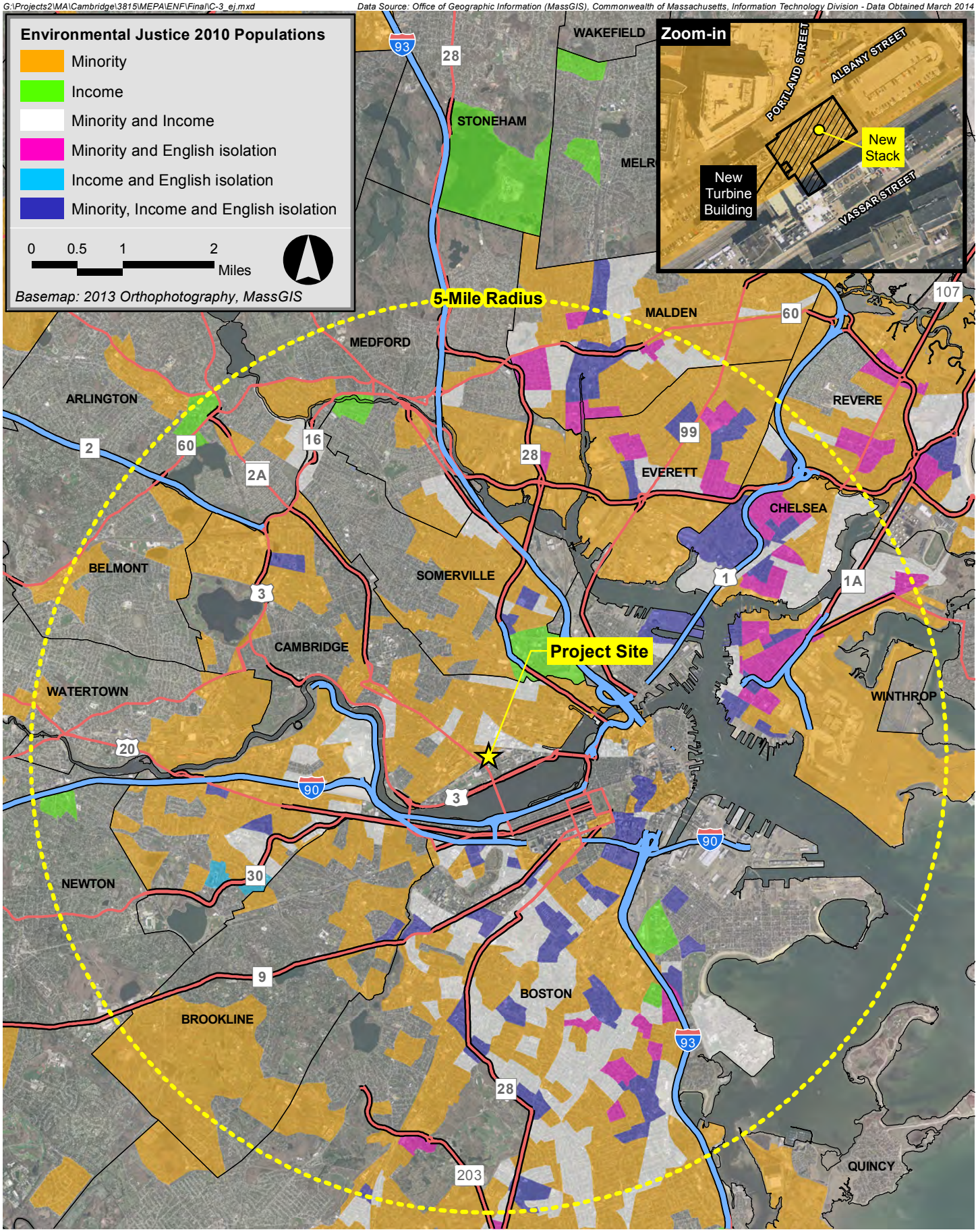
MIT's plan for expanded public outreach includes the following:

- Preparation of a Fact Sheet briefly describing the Project, its impacts, and opportunities to provide comments;
- Fact sheet translation into Spanish, Portuguese, Chinese, French;
- Notice to be placed in the Cambridge Chronicle (Thursday), O Jornal (Portuguese paper, Thursday publication), El Mundo (Spanish paper, Thursday publication), Sampan (Chinese, Every other Friday);
- All fact sheets and the ENF will be sent to the Cambridge Public Library, Central Square branch; and
- Spanish, Cantonese, Portuguese interpreters available during MEPA public scoping session.

[8] Environmental Justice Policy of the Executive Office of Environmental Affairs. Available at http://www.mass.gov/eea/docs/eea/ej/ej-policy-english.pdf.

G:\Projects2\MA\Cambridge\3815\MEPA\ENF\Final\C-3_ej.mxd

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division - Data Obtained March 2014



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon Associates Inc.

Figure C-3

Environmental Justice 2010 Populations

C-7 Public Benefit Determination

In November 2007, the Massachusetts House and Senate passed An Act Relative to the Licensing Requirements for Certain Tidelands (HB 4324), which was signed by Governor Patrick on November 15, 2007 (Chapter 168 of the Acts of 2007) (the "Landlocked Tidelands Legislation"). The legislation, among other things, names the Secretary of Energy and Environmental Affairs (EEA) as the "administrator of tidelands," and requires the Secretary of EEA to conduct a "public benefit review" for certain projects on tidelands and to issue a written determination (the "Public Benefit Determination") for these projects. Specifically, the Secretary must conduct a public benefit review for any proposed project located on tidelands and/or on landlocked tidelands that requires an Environmental Impact Report (EIR), pursuant to the Massachusetts Environmental Policy Act.

Under the Landlocked Tidelands Legislation, in making the Public Benefit Determination, the Secretary shall consider the following:

> "Purpose and effect of the development, the impacts on abutters and the surrounding community; enhancement to the property, benefits to the public trust rights in tidelands or other associated rights, including but not limited to, benefits provided through previously obtained municipal permits; community activities on the development site; environmental protection and preservation; public health and safety; and the general welfare; provided further that the secretary shall also consider the differences between tidelands and landlocked tidelands and great ponds when assessing the public benefit and shall consider the practical impact of the public benefit on the development."

The legislation outlined above requires analysis of a project's impacts on the public's rights of access, use and enjoyment of tidelands that are protected by Chapter 91, and identification of measures to avoid, minimize, and mitigate any adverse impacts on such rights. Given the project's location, no impacts to the access, use and enjoyment of tidelands protected by Chapter 91 are anticipated. It should also be noted that most of the site is located in uplands, and only a very limited portion of this site is presumed to be landlocked tidelands pursuant to 310 CMR 9.02.

The following sections address the considerations identified in the Landlocked Tidelands Legislation.

C-7.1 Purpose and Effect of the Development

The project is an expansion of MIT's existing Central Utility Plant (CUP), and includes the construction of a new structure attached to the existing CUP that will house two new nominal 22 megawatt (MW) combustion turbine (CT) units fired primarily on natural gas, one of which will replace the existing 21 MW CT. The project also includes a 2 MW ultra low sulfur diesel (ULSD) fired cold start engine unit to be used to start the CTs in emergency conditions, as well as accessory mechanical equipment and a regulator station.

The regulator station provides Eversource Energy access to the high-pressure gas system on MIT's campus for distribution to the surrounding neighborhood during periods of maintenance, repair, and expansion of Eversource Energy's infrastructure in the surrounding area. It is anticipated that Eversource Energy's access to the regulator station will reduce service interruptions to Eversource Energy clients' facilities.

MIT is proposing the project with the intent of meeting the following goals:

- To increase the resiliency of the campus, safeguarding crucial research and public safety by enabling MIT to function during a power-loss event;
- To equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and
- To continue conserving energy and reducing MIT's impact on the environment.

C-7.2 Impact on Abutters and the Surrounding Community

The project will provide a reliable power source to the MIT campus and improve MIT's self-sufficiency, thereby reducing the burden on the community in a power-loss situation. As a further benefit, MIT is providing Eversource Energy (formerly NSTAR) with a location inside the new addition to the plant for a regulator station that gives Eversource Energy access to high-pressure gas on campus. With this access, Eversource Energy can continue providing service to this area of Cambridge even as it develops and expands, without digging up city streets and replacing pipes. The project will allow and host new Eversource Energy equipment to provide the City of Cambridge back-up gas supply to the existing natural gas users, a significant public benefit.

The facility will additionally incorporate a cooling tower water storage system designed to retain rainwater rather than discharging it to the City of Cambridge stormwater system.

The project location serves to consolidateMIT's energy facility at a single location where such use is already active, minimizing impacts to landlocked tidelands. In addition, MIT maintains the adjacent sidewalk allowing for safe access along the edge of the site.

C-7.3 Enhancement to the Property

The project site is currently a surface parking lot adjacent to the existing CUP. Access to the surface parking lot is restricted to MIT affiliated vehicles. The project will include the construction of a new addition to the existing CUP, as well as reconstruction of adjacent sidewalks. The new addition will collect rainwater from the roof and reuse it in the facility's cooling towers, rather than allowing it to flow into the City of Cambridge stormwater system. The reuse of stormwater will thereby decrease the need for potable water from the City water system and reduce the facility's burden on the City's stormwater system during precipitation events.

C-7.4 Benefits to the Public Trust Rights in Tidelands or Other Associated Rights

The project site is located more than one-quarter-mile from the flowed tidelands of the Charles River, is separated from the River by several public right-of-ways, and will not impede public access to or from the waterway. The new addition will be built on an existing private parking lot, and construction will include the reconstruction of the adjacent sidewalk, thereby allowing for safe access by the site.

C-7.5 Community Activities on the Development Site

Given the nature of the project, the project site will remain closed to the public.

C-7.6 Environmental Protection and Preservation

The project will add an addition to an existing energy facility on a site currently used for surface parking in an urban area. The goals of the project are:

- To increase the resiliency of the campus, safeguarding crucial research and public safety by enabling MIT to function during a power-loss event;
- To equip the MIT community with an efficient, reliable power source capable of supporting their groundbreaking work and experimentation; and
- To continue conserving energy and reducing MIT's impact on the environment.

The project meets these goals by:

- Placing the equipment above the flood level, safeguarding it against potential future flooding and thereby allowing the system to continue to provide energy to MIT's campus during certain flooding events;
- Providing a reliable source of energy that is more efficient than conventional energy sources; and

- Keeping harmful pollutants out of the air. The expanded plant will reduce EPA-regulated emissions of nitrogen oxides (NOx) and sulfur dioxide (SO2) by almost 80% compared to conventionally produced energy and by 68% compared with the existing single-turbine system. MIT will increase its plant energy efficiency by approximately 7% and reduce its greenhouse gas emissions by approximately 5% compared to using conventional energy sources. These energy savings are equivalent to the total annual electricity used in 3,400 single-family homes.

C-7.7 Public Health and Safety

The project will use the Best Available Control Technology (BACT) to minimize air emissions. The expanded plant will reduce EPA-regulated emissions of NOx and SOx by almost 80% compared to conventionally produced energy and by 68% compared with the existing single-turbine system. MIT will increase its plant energy efficiency by approximately 7% and reduce its greenhouse gas emissions by approximately 5% compared to using conventional energy sources.

C-7.8 General Welfare

The Project will not result in adverse impacts to the general welfare of the public.

C-7.9 Conclusion

The Project will not adversely impact the public's rights to access, use, or enjoy area tidelands. The project will reconstruct adjacent sidewalks, allowing for safe passage by the site. The project will allow for increased stability of natural gas provision to the surrounding area and will increase MIT's self-reliance and public safety capabilities during power-loss and flooding events. The project will also create fewer air pollutants compared to conventionally produced energy, a benefit to the local and regional area. These significant public benefits are achieved with de minimis impact to public trust rights in the limited area of landlocked tidelands on the project site.

Estimating Tool: Net GHG Reduction[1] Achieved by a CHP System Operating in Mass. (ISO-NE Region).

1) All GHG reduction expressed in short tons per year as CO2

Spreadsheet provided by J Ballam, DOER, November 7, 2014; calculations and formatting by A Jablonowski, Epsilon, 12/9/2015 using data from S Dwyer, Vanderweil

<u>Instructions</u>: User Inputs (yellow cells): MWH Electricity Generated by CHP ; MMBTU CHP Fuel Consumption; MMBTU Useful Heat Generated by CHP ; CHP System Fuel and Fuel Specific CO2 Emission Factor (FSEF)[2] ; Average Efficiency of Facility Conventional Thermal Conversion Systesm (e.g. furnace or boiler)

2) *NOTE:* Both the Fuel Designation and the applicable FSEF used are to be obtained from the US Energy Information Administration Voluntary Reporting of Greenhouse Gases Program web page : http://www.eia.doe.gov/oiaf/1605/coefficients.html

CHP Electric Generation		CHP Fuel Consumption	CHP Useful Heat	CHP Electical Generating Efficiency	CHP Overall Efficiency @Full Load
MWh/yr	MMBTU/yr	MMBTU/yr	MMBTU/yr	25%	68%
240143	819608	3280630	1421940		

CHP Fuel	CHP Fuel Specific Emission Factor (lbs/MMBTU)	**Site (CHP) Gross (Stack) Emissions, tpy**	Current Marginal Emission Factor for the ISO -NE Grid, lb/MWh	**GHG Displaced from Grid Electricity, tpy**	Average Thermal Efficiency of Facility Conventional Thermal Systems
Natural Gas	117.00	**191917**	941	**112987**	80%

Conventional Thermal Converson System Fuel	Conventional System Fuel Specific Emission Factor (lbs/MMBTU)	**GHG Displaced from Conventional Useful Heat System, tpy**	**Total Source GHG Displaced , tpy**	**Net Source GHG Reduction**	
				TPY	**%**
Natural Gas	117.00	**103,979**	**216967**	**25050**	**12%**

Note 1: Calculation uses the current draft marginal CO2 emission factor. Using the average CO2 emission factor, net source GHG reduction would be negative 766 tons/year, indicating a GHG increase over the baseline case of separate steam generation and electricity purchase.

Note 2: If the Medium Temperature Hot Water project is implemented in the future, the CHP useful heat would increase by approximately 136,000 MMBtu/yr. Using the calculation methods above, this would equate to approximately 9945 tpy of additional net source GHG reduction.

``

Attachment D

MCPA Application

New Nominal 44 MW CoGen Project

Massachusetts Institute of Technology

Major Comprehensive Plan Approval Application (310 CMR 7.02)

Transmittal # X262114

Submitted to:

Department of Environmental Protection
Northeast Regional Office
205B Lowell Street
Wilmington, MA 01887

Prepared for:

MIT Department of Facilities
Building NE49, 2nd Floor
600 Technology Square
Cambridge, MA 02139

Prepared by:

Epsilon Associates, Inc.
3 Clock Tower Place, Suite 250
Maynard, MA 01754

December, 2015

TABLE OF CONTENTS

LIST OF TABLES III

1.0 INTRODUCTION 1-1
- 1.1 Project Overview – Combustion Turbine Expansion 1-1
- 1.2 Project Overview – Other Proposed Changes 1-2
- 1.3 Outline of Application 1-2

2.0 PROJECT DESCRIPTION AND EMISSIONS 2-1
- 2.1 Description of Project Site 2-1
- 2.2 Project Description 2-3
- 2.3 Source Emissions Discussion 2-3
- 2.4 Exhaust Design Configurations 2-5
- 2.5 Project Schedule 2-5

3.0 APPLICABLE REGULATORY REQUIREMENTS 3-1
- 3.1 Ambient Air Quality Standards and Policies 3-2
- 3.2 Prevention of Significant Deterioration (PSD) Review 3-3
- 3.3 Non-Attainment New Source Review 3-4
- 3.4 New Source Performance Standards 3-5
- 3.5 National Emission Standards for Hazardous Air Pollutants 3-6
- 3.6 Emissions Trading Programs 3-6
- 3.7 Visible Emissions 3-7
- 3.8 Short-term NO_2 Policy 3-7
- 3.9 Noise Control Regulation and Policy 3-7
- 3.10 Air Plan Approval 3-8
- 3.11 Industry Performance Standards 3-8
- 3.12 Fuel Switching 3-8
- 3.13 Operating Permit 3-9
- 3.14 Compliance Assurance Monitoring 3-9
- 3.15 Massachusetts Environmental Policy Act 3-9

4.0 BACT ANALYSIS 4-1
- 4.1 Massachusetts Best Achievable Control Technology (BACT) Requirement 4-1
- 4.2 PSD BACT 4-2
- 4.3 Top-Case BACT from MassDEP Guidance for Combustion Turbines and Duct Burners 4-2
- 4.4 Proposed Variations from Top-case BACT 4-3
- 4.5 Particulate Matter BACT for the Combustion Turbines and Duct Burners 4-4
  - 4.5.1 BACT Applicability 4-4
  - 4.5.2 Step 1--Identify All Control Technologies 4-5
  - 4.5.3 Step 2--Eliminate Technically Infeasible Options 4-6

TABLE OF CONTENTS (Continued)

4.5.4 Step 3--Rank Remaining Control Technologies By Control Effectiveness 4-9
4.5.5 Steps 4&5--Select BACT 4-10
4.6 NOx BACT 4-11
4.6.1 BACT Applicability 4-11
4.6.2 Step 1--Identify All Control Technologies 4-12
4.6.3 Step 2--Eliminate Technically Infeasible Options 4-13
4.6.4 Step 3--Rank Remaining Control Technologies By Control Effectiveness 4-15
4.6.5 Steps 4&5--Select BACT 4-16
4.7 CO BACT 4-17
4.7.1 BACT Applicability 4-17
4.7.2 Step 1--Identify All Control Technologies 4-18
4.7.3 Step 2--Eliminate Technically Infeasible Options 4-19
4.7.4 Step 3--Rank Remaining Control Technologies By Control Effectiveness 4-20
4.7.5 Steps 4&5--Select BACT 4-21
4.8 VOC BACT 4-22
4.8.1 BACT Applicability 4-22
4.8.2 Step 1--Identify All Control Technologies 4-23
4.8.3 Step 2--Eliminate Technically Infeasible Options 4-24
4.7.4 Step 3--Rank Remaining Control Technologies By Control Effectiveness 4-25
4.8.5 Steps 4&5--Select BACT 4-26
4.9 GHG BACT 4-27
4.9.1 BACT Applicability 4-27
4.9.2 Step 1--Identify All Control Technologies 4-28
4.9.3 Step 2--Eliminate Technically Infeasible Options 4-29
4.9.4 Step 3--Rank Remaining Control Technologies By Control Effectiveness 4-31
4.9.5 Steps 4&5--Select BACT 4-32
4.10 Startup Periods, Shutdown Periods, and Fuel Changes 4-33
4.11 Proposed CTG & HRSG Emission Limits 4-33
4.12 Top-Case BACT for Cooling Towers 4-35
4.13 Top-Case BACT for Cold-Start Engine 4-35
4.14 Top-Case BACT for Boilers 7 and 9 4-37

List of Appendices

Appendix A Permit Forms
Appendix B Supplemental Information
Appendix C Supporting Calculations
Appendix D Air Quality Dispersion Modeling Analysis
Appendix E Acentech Noise Report

List of Figures

Figure 2-1 Aerial Locus Map

List of Tables

Table 2-1 Key Existing Equipment at the MIT Plant
Table 2-2 Proposed Emission Rates for CTGs
Table 2-3 Proposed Project Potential Emissions

Table 3-1 Summary of Applicable Requirements
Table 3-2 National and Massachusetts Ambient Air Quality Standards (MAAQS), SILS, & PSD Increments
Table 3-3 Comparison of Project Emissions to PSD Triggers

Table 4-1 Proposed Top-Case BACT from MassDEP
Table 4-2 Summary of available data on PM turbine emission limits
Table 4-3 Summary of PM effectiveness of clean fuels & combustion
Table 4-4 Summary of available data on NOx turbine emission limits
Table 4-5 Summary of CO effectiveness of clean fuels, combustion and Oxidation Catalyst
Table 4-6 Summary of available data on CO turbine emission limits
Table 4-7 Summary of CO effectiveness of clean fuels, combustion and Oxidation Catalyst
Table 4-8 Summary of available data on VOC turbine emission limits
Table 4-9 Summary of VOC effectiveness of clean fuels, combustion and Oxidation Catalyst
Table 4-10 Summary of CO_2e effectiveness of clean fuels & combustion
Table 4-11 Proposed Short-Term Emission Limits Per CHP Unit
Table 4-12 Proposed Long-Term Emission Limits for the CTGs and HRSGs
Table 4-13 Top-Case BACT from MassDEP Guidance for Emergency IC Engines
Table 4-14 Proposed Top-Case BACT for Boilers 7 and 9

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."*

---

[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 Federal, state and local air quality regulations applicable to the CHP expansion.

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

Appendices include the application forms, supplemental information, calculation details, air quality dispersion modeling results, and Acentech's Noise Report.

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.

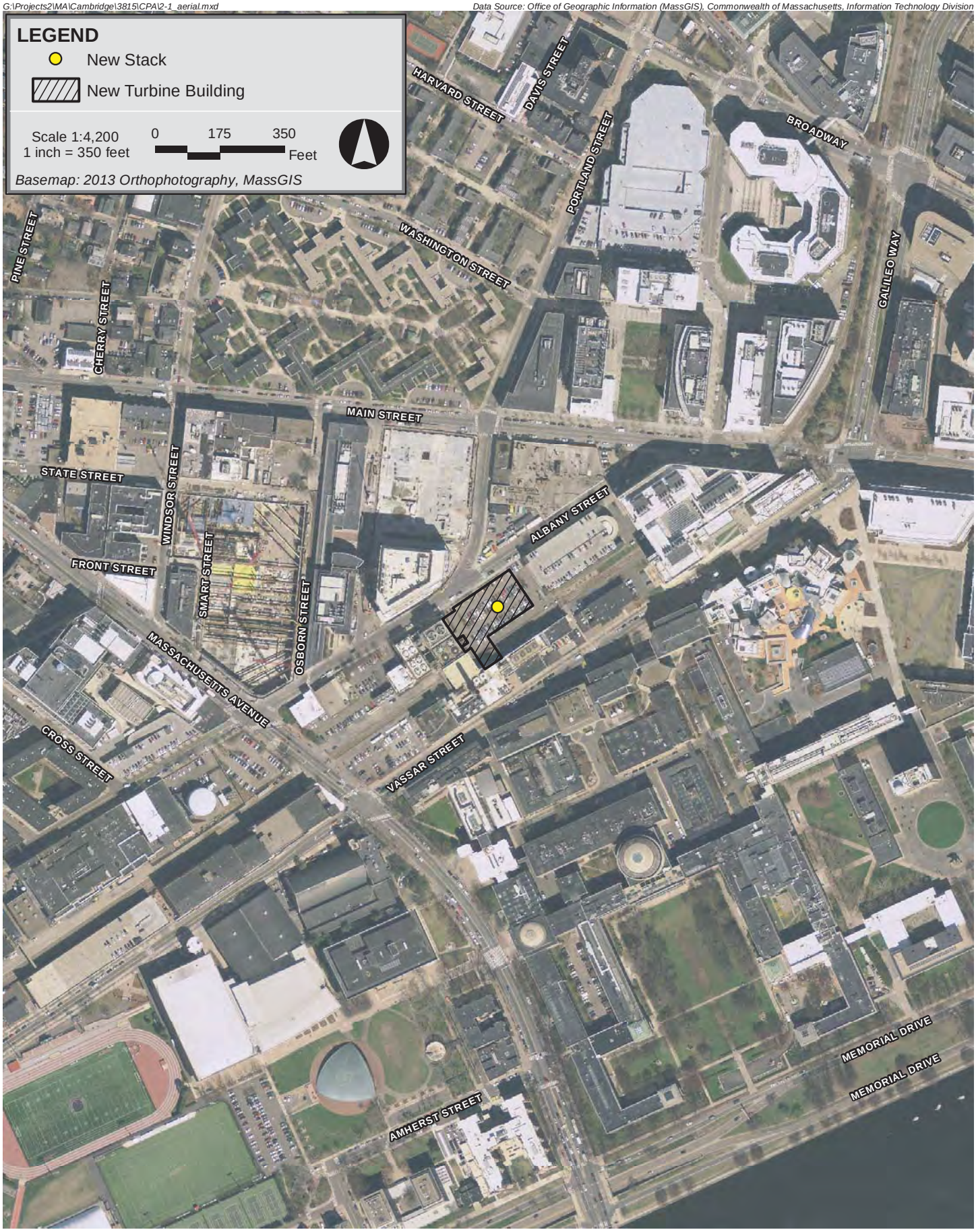
Table 2-1 describes the key equipment at the CUP, and lists the equipment designation abbreviations used in operating permit (Application MBR-95-OPP-026).

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.

G:\Projects2\MA\Cambridge\3815\CPA\2-1_aerial.mxd

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 APPLICABLE REGULATORY REQUIREMENTS

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.

Regulatory requirements are summarized in Table 3-1, below:

Table 3-1 Summary of Applicable Requirements

Regulatory Program	Applicability
Ambient Air Quality Standards and Policies	Applies and compliance is documented through air quality dispersion modeling in the air plan approval process
Prevention of Significant Deterioration (PSD) Review	Applies and is the subject of a separate PSD permit application
Non-Attainment New Source Review	Does not apply
New Source Performance Standards	The CT's are subject to 40 CFR 60 Subpart KKKK. The cold-start -emergency engine is subject to 40 CFR 60 Subpart IIII. Boilers 7 and 9 continue to be subject to 40 CFR 60 Subparts Dc and Db, respectively.
National Emission Standards for Hazardous Air Pollutants	Subpart ZZZZ for cold-start engine.
Emissions Trading Programs	The new CT's are subject to 310 CMR 7.32 as applicable. The new units will not be subject to federal Clean Air Interstate Rule, the federal Acid Rain Program, or the Regional Greenhouse Gas Initiative.
Visible Emissions	Applies and will be complied with
Noise Control Regulation and Policy	Applies and is satisfied through the noise analysis in the air plan approval process
Air Plan Approval	Applies and is satisfied through this air plan approval application
Operating Permit	Applies and will be satisfied through an operating permit modification application after the air plan approval is issued
Compliance Assurance Monitoring	Does not apply
Massachusetts Environmental Policy Act (MEPA) Review	Applies and will be satisfied through separate filings to the MEPA office

3.1 Ambient Air Quality Standards and Policies

The EPA has developed National Ambient Air Quality Standards (NAAQS) for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are SO_2; particulate matter having an aerodynamic diameter of 10 micrometers or less (PM_{10}); particulate matter having an aerodynamic diameter of 2.5 micrometers or less ($PM_{2.5}$); nitrogen dioxide (NO_2); carbon monoxide (CO); ozone (O_3); and lead (Pb). The EPA has recently updated some NAAQS; Table 3-2 summarizes the standards as currently presented by the EPA and MassDEP.

Table 3-2 National and Massachusetts Ambient Air Quality Standards (MAAQS), 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}	Annual (6)	50	Same	1	4	17
	24-hour (7)	150	Same	5	8	30
CO	8-hour (2)	10,000	Same	500	None	None
	1-hour (2)	40,000	Same	2,000	None	None
Ozone	8-hour (8)	148	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) EPA revoked the annual PM_{10} NAAQS in 2006.
(7) Not to be exceeded more than once per year on average over 3 years
(8) Annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years. MAAQS is 235 $\mu g/m^3$.

Source: http://epa.gov/air/criteria.html

The NAAQS consist of primary and secondary standards. Primary standards are intended to protect human health. Secondary standards are intended to protect public welfare from known or anticipated adverse effects associated with the presence of air pollutants, such as damage to property or vegetation. NAAQS have been developed for various durations of exposure. Massachusetts Ambient Air Quality Standards (MAAQS) are codified in 310 CMR 6, and generally follow the NAAQS but have not yet been updated to reflect recent revisions.

One of the basic goals of federal and state air regulations is to ensure that ambient air quality, including the impact of background, existing sources, and new sources, is in compliance with ambient standards. Toward this end, all areas of the country have been classified as in "attainment," "non-attainment", or "unclassified" for a particular contaminant.

The City of Cambridge in Middlesex County is presently designated as unclassified (treated as attainment) or attainment for SO_2, CO, PM_{10}, $PM_{2.5}$, and Pb. The entire Commonwealth of Massachusetts, including Middlesex County is classified as moderate non-attainment for O_3 (8-hr standard).

MassDEP regulates compliance with NAAQS and MAAQS through the Massachusetts Air Plan Approval process, discussed below.

3.2 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 3-3.

Table 3-3 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 3-3 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.

3.3 Non-Attainment New Source Review

If an area is designated as "non-attainment" for a given contaminant and if the proposed facility is a major source of the non-attainment contaminant, a procedure known as Non-Attainment New Source Review (NSR) applies. The Non-Attainment NSR regulations have more stringent requirements than PSD review for source control and for securing emissions offsets.

As discussed in Section 3.1, above, the entire Commonwealth of Massachusetts is classified as a moderate non-attainment area for O_3. However, because O_3 is not directly emitted, it is considered a secondary pollutant that is photochemical produced as a function of both VOC and NO_x emissions. Therefore, VOC and NO_x are regulated as the precursors of O_3. Non-attainment NSR relative to O_3 is required only for new major sources of VOC and/or NO_x or major modifications at existing major sources.

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 will be below the 310 CMR 7.00: Appendix A major source modification threshold of 25 tpy for an existing major source of NOx.

MIT is not an existing major source of VOC. While the Project VOC potential is greater than 25 tpy, the major modification threshold for an existing major source (which MIT is not), it is less than 50 tpy, the major source threshold for an existing minor source of VOC.

Therefore Non-Attainment NSR does not apply to VOC emissions. Upon implementation of this Project, MIT will become a major source of VOC emissions, and future projects will be subject to the 25 ton/year major modification threshold.

3.4 New Source Performance Standards

New Source Performance Standards (NSPS) regulate the amount of air contaminants that may be emitted from a given process. For combustion sources, emission standards are typically expressed in terms of mass emissions per unit of fuel combusted, fuel quality, or exhaust gas concentration. The EPA has established NSPS for various categories of new sources.

Each CT is subject to NSPS under 40 CFR 60 Subpart KKKK, Standards of Performance for Stationary Combustion Turbines. Subpart KKKK limits SO_2 to 0.060 lb/MMBtu heat input and NO2 to 2.3 lb/MWH for natural gas-fired and NO2 to 5.5 lb/MWH for distillate oil fired units. The proposed emission limits are well below the Subpart KKKK limits.

New regulations on the Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units were finalized by EPA on August 3, 2015. These regulations found in 40 CFR 60, Subpart TTTT apply to any units considered an electric generating unit (EGU) that does not meet the exemption criteria set forth in subpart TTTT. The rule's preamble states that to be considered an EGU, a unit must "(1) be capable of combusting more than 250 MMBtu/h (260 GJ/h) heat input of fossil fuel; and (2) serve a generator capable of supplying more than 25 MW net to a utility distribution system (i.e., for sale to the grid)." Since the proposed turbines are nominally 22 MW, they fall below the limit described in point (2) of serving a generator capable of supplying greater than 25 MW net, the output of the generator is for MIT use only and not exported to the electric utility system and are thus not subject to the new NSPS rules set forth in 40 CFR 60, Subpart TTTT from August 3, 2015.

The new cold-start engine is subject to NSPS under 40 CFR 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). The proposed cold-start engine will comply with this standard by imposing annual operating hour limits and work practices, in lieu of emission limits. The emergency cold-start engine will be certified per the MassDEP Environmental Results Program (ERP) and comply with EPA standards for non-road engines, as well as the NSPS regulations at 40 CFR 60 Subpart IIII for stationary emergency engines.

The existing Boilers 7 and 9 are subject to NSPS under 40 CFR 60 Subpart Dc and Db, respectively. No new requirements are triggered.

Boilers 3, 4, and 5 pre-date the NSPS program, and the proposed operational changes (removal of #6 oil firing with the replacement of 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) do not impact the status of these boilers vis-à-vis the NSPS program.

3.5 National Emission Standards for Hazardous Air Pollutants

Realizing that numerous pollutants did not meet the specific criteria for development of a NAAQS, Congress included Section 112 in the 1990 Amendments of the CAA to specifically address this problem. Section 112 provides the EPA with a vehicle for developing standards for potentially hazardous pollutants. The regulations that have been developed to implement Section 112(b) are presented in 40 CFR Parts 61 and 63.

EPA has finalized National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial/Commercial/Institutional Boilers and Process Heaters at Major and Area Sources. MIT is an Area Source of HAPs (potential emissions <25 tons/year total HAPs, <10 tons/year each individual HAP). There are no Area Source requirements for boilers that only fire natural gas, such as this project's HRSG. The proposed changes to Boiler 3, 4, 5, 7, and 9 do not trigger requirements under this NESHAP; on the contrary, after the proposed changes the boilers will be "gas-fired boilers" as defined in 40 CFR 63.11237, and will no longer be subject to 40 CFR 63 Subpart JJJJJJ.

The new CHP turbines are not subject to the NESHAP for Stationary Combustion Turbines (Subpart YYYY) as it only applies to major sources of HAPs. The MIT facility produces less than the threshold of HAPs in tons per year and is not a major source.

Also, as an area source of HAPs, the cold-start engine is subject to 40 CFR Part 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. Per 40 CFR 63.6590(c)(1), the cold-start engine meets the requirements of 40 CFR Part 63 Subpart ZZZZ by meeting the requirements of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."

3.6 Emissions Trading Programs

Each new CHP is less than 25 MWe and therefore not subject to the federal Clean Air Interstate Rule, the federal Acid Rain Program, or the Regional Greenhouse Gas Initiative.

The Clean Air Interstate Rule ("CAIR") is a federal regulatory program controlling emissions of ozone precursors and fine particulates in the eastern United States; effective in 2009 and implemented in Massachusetts as 310 CMR 7.32. CAIR has functioned as an emission trading program similar to the Acid Rain Program and the Regional Greenhouse Gas Initiative ("RGGI"). Under CAIR, applicable Massachusetts emission sources need to hold

or procure sufficient "allowances" to cover actual NO_x emissions for the prior ozone season (May-September). The new CTs will be greater than the size threshold (250 MMBtu/hr) for inclusion per 310 CMR 7.32.

As of January 1, 2015, the Commonwealth of Massachusetts is no longer subject to the CAIR program or its replacement, the Cross-State Air Pollution Rule (CSAPR, aka "Transport Rule"), since it was determined not to contribute to air pollution in downwind states.

As of July 14, 2015, MassDEP indicated that any rulemaking to implement a successor to the CAIR rule is currently on hold pending a review of consistency with MA Executive Order 562 "To Reduce Unnecessary Regulatory Burden."

In the meantime, per MassDEP instructions[2] there are currently no ozone season NOx allowance holding requirements; only the monitoring, reporting, and recordkeeping requirements of 310 CMR 7.32(8-9) are effective. MIT will comply with the applicable regulations at the time of operation, by participating in the NO_x monitoring and reporting methods specified in 40 CFR 75, and obtaining allowances in the event that a new program is set up.

3.7 Visible Emissions

Massachusetts regulation (310 CMR 7.06) limits smoke to No. 1 on the Ringlemann Chart (except for six minutes in an hour up to No. 2 on the Chart) and limits opacity to 20% (except for two minutes in an hour up to 40%). MIT intends to comply using Continuous Opacity Monitoring System (COMS) to demonstrate compliance.

3.8 Short-term NO_2 Policy

On April 20, 1978 and in an update on November 3, 1980 MassDEP adopted a policy entitled "New Source Performance Criteria for Allowable Ambient NO_2 Concentrations." The policy applies only to new major sources or modifications to an existing source, which would result in increased emissions of 250 tpy of NO_x. The Project's potential emissions are well below this threshold.

3.9 Noise Control Regulation and Policy

MassDEP regulations, set forth in 310 CMR 7.10 and as interpreted in the MassDEP Noise Policy 90-001, limit noise increases to 10 dBA over the existing L_{90} ambient level at the closest residence and at property lines. For developed areas, the MassDEP has utilized a "waiver provision" at the property line in certain cases. This may occur when the impact is in an area that is not noise-sensitive such as an adjacent industrial parcel. The ambient

[2] http://www.mass.gov/eea/docs/dep/air/approvals/cair-email.pdf, December 31, 2014

noise level may also be established by other means with MassDEP consent. MassDEP also prohibits "pure tone" sounds, defined as any octave band level that exceeds the levels in the two adjacent octave bands by 3 dB or more. Noise considerations are discussed in an appendix to this application. The Project will comply with all components of the MassDEP Noise Policy 90-001 as indicated in Appendix E.

3.10 Air Plan Approval

The Project is subject to MassDEP Air Plan Approval (permit) requirements under 310 CMR 7.02. The purpose of Air Plan Approval review is to ensure that these new and modified sources will be in compliance with all applicable federal and DEP air regulatory requirements, including emission standards and ambient air quality criteria.

In addition to the federal and state limits and standards described above which are implemented through the MassDEP Air Plan Approval review, Massachusetts regulations require the application of Best Available Control Technology (BACT) for each regulated pollutant. Massachusetts BACT is based on the maximum degree of reduction of any regulated air contaminant that the MassDEP determines, on a case-by-case basis, is achievable taking into account energy, environmental, and economic impacts. A BACT determination can never result in a less stringent emission limitation than an applicable emission standard. Depending on the circumstances, BACT may parallel with the emission standard or may be more stringent than the emission standard. BACT itself is a standard that balances emission control benefits with technical feasibility, other environmental impacts and costs. Application of BACT is demonstrated in Section 4 of this application. The proposed Project meets BACT.

Compliance with ambient air quality criteria is demonstrated in Appendix D.

3.11 Industry Performance Standards

The Massachusetts Industry Performance Standards in 310 CMR 7.26 do not apply to this project. Specifically, the Engines and Turbines section at 7.26(43) and the Combined Heat and Power section at 7.26(45) only apply to turbines smaller than 10 MW.

3.12 Fuel Switching

Per 310 CMR 7.02(8)(b), the conversion of Boilers 3, 4, and 5 from #6 oil fuel to natural gas with ULSD backup does not trigger an assessment of BACT in this application for plan approval, and is not considered a major modification subject to 310 CMR 7.00: Appendix A. The fuel switch is a pollution control project as defined in 310 CMR 7.00: Appendix A because it is "an activity or project to accommodate switching to a fuel which is less polluting than the fuel used prior to the activity or project."

3.13 Operating Permit

MIT is subject to the operating permit requirements in 310 CMR 7.00, Appendix C. MIT has an operating permit (MBR-95-OPP-026 MM) pursuant to this program (sometimes referred to as a "Title V" permit because the program was originally initiated by Title V of the Clean Air Act Amendments of 1990). After receipt of an Air Plan Approval, MIT will apply to modify the operating permit to reflect the conditions of the Air Plan Approval. That modification will include addition of the new units to the facility-wide emission limits.

3.14 Compliance Assurance Monitoring

The Compliance Assurance Monitoring requirements at 40 CFR 64 applies when an emission unit uses a control device to comply with certain emission limits, the potential emissions before control are above major source thresholds, and the operating permit does not specify a continuous compliance determination method, such as CEMS. While the new CHPs will use control devices (SCR and oxidation catalyst) to comply with NOx and CO emission limits, MIT will use a CEMS to continuously determine compliance. The Compliance Assurance Monitoring requirements therefore do not apply to the project.

3.15 Massachusetts Environmental Policy Act

Per the Massachusetts Environmental Policy Act (MEPA) Office website, MEPA requires that state agencies study the environmental consequences of their actions, including permitting and financial assistance. It also requires them to take all feasible measures to avoid, minimize, and mitigate damage to the environment.

MEPA further requires that state agencies "use all practicable means and measures to minimize damage to the environment," by studying alternatives to the proposed project, and developing enforceable mitigation commitments, which will become conditions for the project if and when they are permitted.

The Project triggers review through the MEPA review process. MIT will consult separately with the MEPA office to confirm the appropriate procedure to document completion of the MEPA review process for this project.

MassDEP is precluded from issuing the MCPA until the MEPA review process has concluded, to ensure that MassDEP is aware of the environmental consequences associated with permit issuance. MIT expects to conclude the MEPA review process within the normal time window for MassDEP review of this MCPA and the PSD application.

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). Different pollutants are subject to different BACT requirements. The applicable requirements are discussed in detail in this Section, followed by descriptions of how BACT is applied for each separate pollutant.

4.1 Massachusetts Best Achievable Control Technology (BACT) Requirement

The plan approval requirements at 310 CMR 7.02(5) require BACT. BACT is defined in 310 CMR 7.00 as,

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

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

MassDEP has a lengthy history of determining BACT for combustion sources of the size proposed for the CHP expansion, and has applicable regulations and guidance defining "top-case BACT." For pollutants where top-case BACT is proposed, a detailed, exhaustive top-down analysis would be "reinventing the wheel." This application presents a formal BACT analysis for PM, CO, VOC and CO_2, and relies on MassDEP guidance and information from other available resources for other pollutants. Also, a separate BACT analysis is provided for the proposed ULSD fired cold-start engine.

4.2 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 $PM_{2.5}$, PM10, and CO2e. A formal top-down analysis is presented for particulate matter and CO2e.

4.3 Top-Case BACT from MassDEP Guidance for Combustion Turbines and Duct Burners

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources[3] to document BACT. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Specifically, MIT proposes the emission rates in Table 4-1 below as top-case BACT:

Table 4-1 Proposed Top-Case BACT from MassDEP

Source	Fuel	Air Contaminant	Emission Limitations	Control Technology
Combustion Turbine (>10 MW)	Natural Gas	NO_x	2.0 ppmvd at 15 % O2	Dry Low NOx Combustor, SCR, Oxidation catalyst, NOx, CO, NH3 CEMS
		NH_3	2.0 ppmvd at 15 % O2	
		CO	2.0 ppmvd at 15 % O2	
		VOC	1.7 ppmvd at 15 % O2	

[3] http://www.mass.gov/eea/docs/dep/air/approvals/bactcmb.pdf, accessed 7/10/14

Table 4-1 Proposed Top-Case BACT from MassDEP (Continued)

Source	Fuel	Air Contaminant	Emission Limitations	Control Technology
Combustion Turbine (>10 MW)	Ultra Low Sulfur Distillate Oil 0.0015 %	NH_3	2.0 ppmvd at 15 % O2	Dry Low NOx Combustor, SCR, Oxidation catalyst, NOx, CO, NH3 CEMS
		CO	7.0 ppmvd at 15 % O2	
		VOC	7.0 ppmvd at 15 % O2	
Duct Burner (boiler >100 MMBtu/hr)	Natural Gas	NO_x	0.011 lb/MMBtu	Low NOx burners, SCR, Oxidation catalyst, NOx, CO CEMS
		CO	0.011 lb/MMBtu	
		VOC	0.03 lb/MMBtu	

MIT proposes to fire the duct burner using natural gas exclusively.

While not specifically listed in the MassDEP guidance, MIT proposes the following as top-case BACT:

- Sulfur dioxide (SO2) BACT is met through the use of low-sulfur fuels (natural gas and ultra-low sulfur diesel), and efficient operation. MIT will track sulfur content through vendor-posted data and fuel receipts.

4.4 Proposed Variations from Top-case BACT

MIT proposes the following changes from Massachusetts guidance for Top-Case BACT:

- MIT proposes a NOx emission rate of 9 ppmvd at 15% O2 when firing ULSD, instead of the Massachusetts top-case BACT guidance of 7 ppmvd at 15% O2. This proposed change allows the use of a dry low-NOx combustor for the CTGs, which has environmental and reliability benefits.

- MIT proposes to meet other top-case BACT guidance during full-load, steady state conditions. However, the CTGs must be able to quickly and reliably respond to changes in campus energy demand. Meeting the same limits as apply for full-load steady-state conditions will not be possible over the short term. The proposed emission limits during part-load and transient operations are:

  - Proposed NOx firing gas from the CTG of 3.2 ppmvd at 15% O2 during operation below 90% load.

  - Proposed NOx firing gas from the CTG of 4.0 ppmvd at 15% O2 during operation below 90% load and ambient air temperatures below 30 degrees Fahrenheit.

- Proposed CO firing gas from the CTG of 5.0 ppmvd at 15% O2 during operation during operation at 50% load or lower, or during periods when operating load is changing significantly.

- Proposed VOC firing gas from the CTG of 3 ppmvd at 15% O2 during operation during operation at 50% load or lower, or during periods when operating load is changing significantly.

- Proposed NH3 firing gas from the CTG of 5.0 ppmvd at 15% O2 during operation during operation at 50% load or lower, or during periods when operating load is changing significantly.

When operating load is changing significantly the turbine controls automatically can transition out of dry-low-NOx (DLN) mode. MIT proposes that when the unit is not in DLN mode that a higher emission limit is needed.

4.5 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.

4.5.1 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.

4.5.2 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.

4.5.3 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[4] 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[5] has no guidance for particulate matter;

- Control technology vendors - An online review of vendors[6] does not find any offering post-combustion control for particulate matter from combustion turbines firing natural gas or distillate oil;

- 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;

---

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

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

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

- Technical journals, reports and newsletters, air pollution control seminars - a review of papers posted by the Air and Waste Management Association[7] 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[8] 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[9]. 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:

Table 4-2 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

7 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.

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

9 EPA-452/F-03-031

Table 4-2 Summary of available data on PM turbine emission limits (Continued)

Determination	PM emission limit	Converted
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

4.5.4 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 4-3 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.

4.5.5 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.

4.6 NOx BACT

While NOx emissions are only subject to 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.

4.6.1 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.

NOx is formed during the combustion process due to the reaction between nitrogen and oxygen in the combustion air at the high temperatures ("thermal NOx") and the reaction of nitrogen bound in the fuel with oxygen ("fuel NOx"). Fuel NOx is minimal from the combustion of natural gas or ULSD.

MIT proposes to meet DEP's top case BACT of 2.0 ppmvd @ 15% O2 for the combustion turbine firing natural gas at 100% load by using an oxidation catalyst designed for 92% removal. The proposed dry-low NOx combustors will have elevated NOx emissions at part-load and at low ambient air temperatures. MIT proposes an emissions limit of 3.2 ppmvd at 15% O2 for loads below 90%, and 4 ppmvd at 15% O2 for loads below 90% and ambient temperatures below 30 degrees Fahrenheit.

During ULSD firing, MIT proposes to meet a limit of 9.0 ppmvd at 15% O2. While this is higher than the MassDEP top-case BACT guidance, proposed ULSD use is very limited and the higher emission limit allows the use of dry low-NOx combustors, which have other environmental advantages.

4.6.2 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:
  - Selective Catalytic Reduction
  - Selective Non-Catalytic Reduction
  - EMx (SCONOX) Systems
  - XONON Systems
- The use of clean fuels and good combustion control, including:
  - Dry Low-NOx combustors
  - Low-NOx combustors with water injection ("wet combustors")

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 CHP 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 and thermal energy in a combustion turbine.

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, combined with SCR.

4.6.3 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, including:
  - Selective Catalytic Reduction *technically feasible*
  - Selective Non-Catalytic Reduction *technically infeasible*
  - EMx (SCONOX) Systems *technically infeasible*
  - XONON Systems *technically infeasible*
- The use of clean fuels and good combustion control, including:
  - Dry Low-NOx combustors *technically feasible*
  - Low-NOx combustors with water injection ("wet combustors") *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.

- SNCR uses the same chemical reduction principle as SCR, but without the catalyst. Instead, the combustion unit acts as a reactor chamber (and removal efficiencies are lower). The effectiveness of SNCR would be limited on a combustion turbine because there is insufficient reactor residence time, and changes to load would make it difficult to maintain the proper temperature window. EPA's Air Pollution Control Technology Fact Sheet for SNCR[10] states that SNCR is "not applicable to sources with low NO_x concentrations such as gas turbines."

- Two other technologies were considered, but were determined not to be technically feasible for the Facility. These are: 1 Kawasaki's Catalytica's catalytic combustion-based technology, K-LeanTM (formerly XONON) for NOx control, and 2) Emerachem's EMxTM (formerly SCONOx) post-combustion system for NOx control. Neither technology has sufficient operating experience to be relied on as critical infrastructure for the MIT campus.

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.

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. Additional facilities were added based on Epsilon experience.

Key projects are summarized as follows:

[10] EPA-452/F-03-031

Table 4-4 Summary of available data on NOx turbine emission limits

Determination	NOx emission limit	Converted
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	52.0 lb/hr	0.26 lb/MMBTU
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	15 ppmvd @ 15% O2 on natural gas below 0 °F 25 ppmvd @ 15% O2 on ULSD below 0 °F 9 ppmvd @ 15% O2 on natural gas above 0 °F 2.5 ppmvd @ 15% O2 on ULSD above 0 °F	0.055 lb/MMBTU on natural gas below 0 °F 0.092 lb/MMBTU on ULSD below 0 °F 0.033 lb/MMBTU on natural gas above 0 °F 0.0092 lb/MMBTU on ULSD above 0 °F
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	19.0 lb/hr on natural gas or ULSD below 0 °F 2.56 lb/hr on natural gas above 0 °F 5.94 lb/hr on ULSD above 0 °F	0.148 lb/MMBTU on natural gas or ULSD below 0 °F 0.020 lb/MMBTU on natural gas above 0 °F 0.046 lb/MMBTU on ULSD above 0 °F
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	1.5 lb/hr firing natural gas (with and without duct burning); 4.4 lb/hr PM firing ULSD.	0.020 firing natural gas with duct burning; 0.058 lb/MMBTU PM firing ULSD.
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	2 ppm firing natural gas without duct burning (0.93 lb/hr with duct burning); 1.82 lb/hr firing ULSD	0.014 lb/MMBTU firing natural gas with duct burning; 0.071 lb/MMBTU firing ULSD
MassDEP operating permit for MATEP, Alston turbine & HRSG	2.0 ppmvd @ 15% O2 firing natural gas 6.0 ppmvd @ 15% O2 firing ULSD	0.007 lb/MMBTU firing natural gas 0.022 lb/MMBTU 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; 4.3 lb/hr firing ULSD	0.022 lb/MMBTU firing natural gas with duct burning 0.046 lb/MMMBTU firing ULSD
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	4 ppm at 15% O_2 firing natural gas	0.015 lb/mmbtu firing natural gas
* CHP emission limit at 310 CMR 7.26()		

4.6.4 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 available control technology is the use of clean fuels, clean combustion and SCR. Requested data is summarized below.

Table 4-5 Summary of CO effectiveness of clean fuels, combustion and Oxidation Catalyst

Control efficiencies (percent pollutant removed)	Up to 92% to meet the 2 ppmvd emission limit
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C, potential emissions are a maximum of XX lb/hr firing gas, XX lb/hr firing ULSD in each turbine (and gas in the duct burner), and XX tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	The SCR as proposed will remove approximately 92% of uncontrolled NOx emissions, which will vary based on actual loads operated.
Economic impacts	The use of SCR is cost-effective for NOx control.
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)	Spent SCR catalyst can be recycled or disposed of as solid waste (expected every 5 or 10 years). The use of dry-low NOx combustion reduces water use.
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. The SCR adds some backpressure to the CHP system, resulting in a small energy impact.

4.6.5 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.

The GE LM-2500 dry low-NOx combustor avoids water use, and emits fewer products of incomplete combustion (CO and VOC) than a similar unit with water injection, while achieving the same full-load NOx emission rates. NOx emissions are higher at part-load and at lower ambient temperatures. MIT plans to operate at 100% load as much as economically feasible since that is where the CT is most efficient. Part load operation will be limited by MIT as needed to meet the annual potential to emit limit of 24.6 tpy proposed for the two turbines, including the duct burners and limited hours of operation down to 25% load.

During oil firing, the dry low-NOx combustor emits higher NOx emissions than a similar system with water injection. MIT proposes an emission limit of 9.0 ppmdv down to 50% load. Given that ULSD will be fired only when gas is unavailable, at most 168 hours per year, the difference between this limit and the MassDEP top-case BACT is 0.16 tons per year. The environmental impacts associated with using water injection (water use, higher products of incomplete combustion) outweigh the impacts associated with slightly higher NOx emissions during limited ULSD operating hours.

4.7 CO BACT

While CO emissions are only subject to 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.

4.7.1 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.

Carbon monoxide (CO) is a product of incomplete combustion. MIT proposes to meet DEP's top case BACT of 2.0 ppmvd @ 15% O2 for the combustion turbine firing natural gas at 100% load at 60°F ambient by using an oxidation catalyst designed for 92% removal. At reduced load and during transient operations (when load is changing significantly) CTG emissions of CO increase, and the temperature at the catalyst may make it difficult for the

catalyst to remove all the additional CO emissions. MIT requests a limit of 5 ppmvd @ 15% O2 during operation at 50% load or lower, or during periods when operating load is changing significantly.

Part load operation will be limited by MIT as needed to meet the annual potential to emit limit of 24.6 tpy proposed for the turbines and duct burners, including the duct burners and operation down to 25% load. During oil firing, MIT is able to meet the top case BACT of 7.0 ppmdv down to 50% load.

4.7.2 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:
  - Oxidation catalyst
- 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.

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.

4.7.3 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 feasible*
- 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.

- Not applicable as an oxidation catalyst is being used

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.

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. Additional facilities were added based on Epsilon experience.

Key projects are summarized as follows:

Table 4-6 Summary of available data on CO turbine emission limits

Determination	CO emission limit	Converted
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	32 lb/hr firing natural gas	1.60 lb/MWh 0.15 lb/MMBtu
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	10 ppm firing natural gas 30 ppm firing ULSD	0.40 lb/MWh firing natural gas (0.022 lb/MMBtu) 1.28 lb/MWh firing ULSD (0.071 lb/MMBtu)
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	5 ppm firing natural gas 5 ppm firing diesel	0.28 lb/MWh (0.011 lb/MMBtu) natural gas 0.27 lb/MWh (0.012 lb/MMBtu) ULSD
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	0.9 lb/hr firing natural gas (with and without duct burning); 2.2 lb/hr firing ULSD.	0.12 lb/MWh (0.005 lb/MMBtu) firing natural gas, 0.29 lb/MWh firing ULSD (0.012 lb/MMBtu)
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	2 ppm firing natural gas without duct burning; 0.92 lb/hr firing ULSD	0.051 lb/MWh (0.0045 lb/MMBtu) firing natural gas 0.12 lb/MWh firing ULSD (0.011 lb/MMBtu)
MassDEP operating permit for MATEP, Alston turbine & HRSG	1 ppm firing gas, 2.5 ppm firing gas with duct firing, 5 ppm firing ULSD	0.023 lb/MWh (0.0022 lb/MMBtu) firing natural gas 0.085 lb/MWh (0.0056 lb/MMBtu) firing natural gas with duct firing 0.12 lb/MWh firing ULSD (0.012 lb/MMBtu)
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	6 lb/hr firing natural gas with or without duct firing; 4.8 lb/hr firing ULSD	0.48 lb/MWh* (0.061 lb/MMBtu) firing natural gas 0.68 lb/MWh* (0.04 lb/MMBtu) firing natural gas with duct firing 0.57 lb/MWh* firing ULSD (0.051 lb/MMBtu)
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	1.78 lb/hr firing natural gas	
* CHP emission limit at 310 CMR 7.26()		

4.7.4 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 available control technology is the use of clean fuels, clean combustion and oxidation catalyst. Requested data is summarized below.

Table 4-7 Summary of CO effectiveness of clean fuels, combustion and Oxidation Catalyst

Control efficiencies (percent pollutant removed)	Up to 96% to meet the 2 ppmvd emission limit
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C, potential emissions are a maximum of 10.96 lb/hr firing gas (at 25% load), 4.1 lb/hr firing ULSD in each turbine (and gas in the duct burner), and 21.7 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	The oxidation catalyst as proposed will remove 94-96% of uncontrolled CO emissions, which will vary based on actual loads operated.
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.

4.7.5 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.

Based on the review above, MIT proposes to meet DEP's top case BACT of 2.0 ppmvd @ 15% O2 during full-load, steady state conditions. At reduced load and during transient operations (when load is changing significantly) CTG emissions of CO increase, and the temperature at the catalyst may make it difficult for the catalyst to remove all the additional CO emissions. MIT requests a limit of 5 ppmvd @ 15% O2 during operation at 50% load or lower, or during periods when operating load is changing significantly. MIT proposes the top-case BACT emission limit of 7 ppmvd @15% O2 firing ULSD.

4.8 VOC BACT

While VOC emissions are only subject to 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.

4.8.1 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.

Volatile Organic Compounds (VOCs) are products of incomplete combustion. MIT proposes to meet DEP's top case BACT of 1.7 ppmdv (0.0022 lb/MMBTU) for the combustion turbine firing natural gas at 100% load at 60°F ambient by using an oxidation catalyst designed for 50% VOC removal. At reduced load and during transient operations (when load is changing significantly) CTG emissions of VOC increase, and the temperature at the catalyst may make it difficult for the catalyst to remove all the additional VOC emissions. MIT requests a limit of 3.1 ppmvd @ 15% O2 during operation at 50% load or lower, or during periods when operating load is changing significantly.

4.8.2 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:
  - Oxidation catalyst
- 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.

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.

4.8.3 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 feasible*
- 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.

- Not applicable as an oxidation catalyst is being used.

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.

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. Additional facilities were added based on Epsilon experience.

Key projects are summarized as follows:

Table 4-8 Summary of available data on VOC turbine emission limits

Determination	VOC emission limit	Converted
RBLC determination for Signal Hills Wichita Falls Power (TX), 20 MW turbine, combined cycle	0.87 lb/hr firing natural gas	0.044 lb/MWh 0.0042 lb/MMBtu
NYSDEC operating permit for Cornell University, 15 MW Solar turbine CHP	NA	NA

Table 4-8 Summary of available data on VOC turbine emission limits (Continued)

Determination	VOC emission limit	Converted
Conditional Approval for MassDEP operating permit for UMass Amherst, 10 MW Solar turbine CHP	0.5 lb/hr firing natural gas or 0.87 lb/hr firing diesel	0.045 lb/MWh (0.0041 lb/MMBtu) natural gas 0.079 lb/MWh (0.0074 lb/MMBtu) ULSD
MassDEP operating permit for Gillette Boston, Solar Taurus 70 turbine CHP	0.5 lb/hr firing natural gas or ULSD	0.067 lb/MWh (0.0027 lb/MMBtu) firing natural gas, 0.067 lb/MWh firing ULSD (0.003 lb/MMBtu)
MassDEP operating permit for UMass Medical Center, Solar Taurus 70 turbine CHP	2 ppm firing natural gas without duct burning; 0.21 lb/hr firing ULSD	0.029 lb/MWh (0.0026 lb/MMBtu) firing natural gas 0.028 lb/MWh firing ULSD (0.0025 lb/MMBtu)
MassDEP operating permit for MATEP, Alston turbine & HRSG	1 ppm firing gas, 2.5 ppm firing gas with duct firing, 7 ppm firing ULSD	0.013 lb/MWh (0.0013 lb/MMBtu) firing natural gas 0.049 lb/MWh (0.0032 lb/MMBtu) firing natural gas with duct firing 0.10 lb/MWh firing ULSD (0.0095 lb/MMBtu)
MassDEP operating permit for Harvard, Solar Taurus 70 turbine & HRSG (not yet constructed)	2 lb/hr firing natural gas with or without duct burning; 0.34 lb/hr firing ULSD	0.029 lb/MWh (0.02 lb/MMBtu) firing natural gas 0.23 lb/MWh* (0.013 lb/MMBtu) firing natural gas with duct firing 0.041 lb/MWh firing ULSD (0.004 lb/MMBtu)
RBLC Draft Determination for Lenzing Fibers, Inc. (AL) 25 MW Gas Turbine with HRSG	1.60 ppm firing natural gas	

4.8.4 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 available control technology is the use of clean fuels, clean combustion and oxidation catalyst. Requested data is summarized below.

Table 4-9 Summary of VOC effectiveness of clean fuels, combustion and Oxidation Catalyst

Control efficiencies (percent pollutant removed)	Up to 50% control efficiency for VOC removal
Expected emission rate (tons per year, pounds per hour)	Per the calculations in Appendix C, potential emissions are a maximum of 9.24 lb/hr firing gas at 25% load, _2.34_ lb/hr firing ULSD in each turbine (and gas in the duct burner), and 15.6 tons/year combined total. Expected emission rates are lower.
Expected emissions reduction (tons per year)	The oxidation catalyst as proposed will remove 50% of uncontrolled VOC emissions, which will vary based on actual loads operated.
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.

4.8.5 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.

As described above, MIT proposes to meet DEP's top case BACT of 1.7 ppmdv (0.0022 lb/MMBTU) for the combustion turbine firing natural gas at 100% load at 60°F ambient by using an oxidation catalyst designed for 50% VOC removal. At reduced load and during transient operations (when load is changing significantly) CTG emissions of VOC increase, and the temperature at the catalyst may make it difficult for the catalyst to remove all the additional VOC emissions. MIT requests a limit of 3.1 ppmvd @ 15% O2 during operation at 50% load or lower, or during periods when operating load is changing significantly. During oil firing, MIT is able to meet the top case BACT of 7.0 ppmdv down to 50% load.

4.9 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.[11]"

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.

4.9.1 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.

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

4.9.2 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[12]. 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.

4.9.3 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*

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

[12] 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.

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.

4.9.4 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 4-10 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.

4.9.5 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[13]:

> *"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.

---

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

4.10 Startup Periods, Shutdown Periods, and Fuel Changes

Combustion turbines can experience increased emissions during startup periods, shutdown periods, and fuel changes because operations are not steady-state. Also, the SCR system needs a minimum operating temperature to effectively reduce NOx. MIT will comply with BACT during startup periods, shutdown periods, and fuel changes by employing good operating practices (by following the manufacturer's recommendations during startup), and by limiting startup time. Emissions during startups and shutdowns will be minimized by following manufacturers' Standard Operating Procedures. Start-ups and shutdowns will be per manufacturers' specifications, but will not exceed three hours in duration for each episode as a worst case (cold start).

Additionally, NOx emissions will be minimized startup periods by injecting urea into the SCR system as soon as the catalyst reaches its minimum operating temperature and all system parameters are met. The proposed long-term emission rates include startup periods, shutdown periods, and fuel changes. Short term startup and shutdown emission limits will be proposed after a period of actual operation. Peak startup emissions of CO occur for a few minutes between 10 and 50% load, so the air modeling of the 50% load case also accounts for the startup case. Neither the 1-hr or 8-hr avg CO NAAQS will be exceeded during startup. Peak uncontrolled NOx emissions occur for a few minutes before the turbine enters DLN mode. This would add negligibly to the 1 hour average. Adding the total emissions the total startup to an hour of gas firing would be less than the hourly ULSD fired emissions. The total NOx emission during the first few minutes of ULSD firing would represented the by 50% ULSD firing case. Therefore, the 50% ULSD firing case accounts for NO2 during startup against the 1-hr NO2 NAAQS.

4.11 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 4-11, below. Supporting calculations are in Appendix C.

Table 4-11 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	NOx	3.47 lb/hr at 90-100% load / 2.87 lb/hr below 90% load / 3.43 lb/hr below 90% load below 30 °F	CEMS, based on 1-hour average calculated hourly during normal operation
	CO	2.69 lb/hr at 100% load / 2.87 lb/hr below 50% load	CEMS, based on 1-hour average calculated hourly during normal operation
	NH3	1.6 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
Natural gas, with or without duct firing (continued)	VOC	0.85 lb/hr at 100% load / 1.55 lb/hr below 50% load	Stack testing based on EPA Method 25A or other method approved by MassDEP, every 5 years.
	PM	6.5 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	SO2	1.1 lb/hr	Initial calculations based on rated capacity, emission factor
	CO_2e	46,401 lb/hr	Initial calculations based on rated capacity, emission factor
ULSD in turbine, with or without natural gas duct firing	NOx	10.14 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	CO	5.6 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	NH_3	1.6 lb/hr	CEMS, based on 1-hour average calculated hourly during normal operation
	VOC	6.4 lb/hr	Stack testing based on EPA Method 25A or other method approved by MassDEP, every 5 years.
	PM	11.23 lb/hr	Stack testing based on EPA Method 5/202 or other method approved by MassDEP, every 5 years.
	SO2	0.8 lb/hr	Initial calculations based on rated capacity, emission factor
	CO_2e	57,083 lb/hr	Initial calculations based on rated capacity, emission factor

Emissions of SO_2 and CO_2 will be limited through the use of clean fuels and efficient operation. NO_x, CO, and NH_3 monitoring systems will be installed in accordance with 40 CFR 60 App B and quality assured in accordance with App F. Dedicated COMS will be installed to document compliance with opacity limits per 310 CMR 7.06.

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 4-12, below. The proposed long-term emission rates include startup periods, shutdown periods, and fuel changes.

Table 4-12 Proposed Long-Term Emission Limits for the CTGs and HRSGs

NOx	24.1 ton/12-month rolling period, based on CEMS
CO	17.3 ton/12-month rolling period, based on CEMS
NH3	6.5 ton/12-month rolling period, based on CEMS
VOC	11.5 ton/12-month rolling period, based on stack test data and fuel use
PM	48.3 ton/12-month rolling period, based on stack test data and fuel use
SO2	6.7 ton/12-month rolling period, based on emission factors and fuel use
CO_2e	333,530 ton/12-month rolling period, based on emission factors and fuel use

4.12 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.

4.13 Top-Case BACT for Cold-Start Engine

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources to document BACT for the cold-start engine. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein

may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Where available, MIT proposes to use the MassDEP Top Case (BACT) Guidelines for Combustion Sources to document BACT for the cold-start engine. As stated in the guidelines, "Use of the applicable Top Case BACT emissions limitations contained herein may preclude the need for applicants to prepare and submit a "top-down BACT analysis" for MassDEP's review, and will streamline the Air Quality permitting process for both the applicants and MassDEP."

Table 4-13 below contains the MassDEP Top Case BACT Guideline for Emergency IC Engines equal to or greater than 37 kw.

Table 4-13 Top-Case BACT from MassDEP Guidance for Emergency IC Engines

Source	Fuel	Air Contaminant	Emission Limitations	Control Technology
IC Engines equal to or greater than 37 kw (Emergency Engines)	ULSD (0.0015%)	NOx, PM, CO, VOC	Comply with applicable emission limitations set by US EPA for non-road engines at 40 CFR 89	N/A

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.

4.14 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 4-14 below compares the proposed limits for Boilers 7 and 9 compared to the relevant 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 4-14 Proposed Top-Case BACT for Boilers 7 and 9

Pollutant	Natural Gas		ULSD	
	Limit (lb/MMBTU)	BACT Guidance (lb/MMBTU)	Limit (lb/MMBTU)	BACT Guidance (lb/MMBTU)
CO	0.011*	0.011	0.035	0.035
NOx	0.011	0.011	0.1	0.1
PM10/PM2.5	0.01	0.01	0.03	0.03
SO2	0.0014	N/A	0.0016	N/A
VOC	0.03	0.03	0.03	0.03
CO2	119	N/A	166	N/A

* Boiler 9 has a CO limit of 0.033 lb/MMBtu at loads below 33%.

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.

APPENDIX A

Permit Forms

Enter your transmittal number → X262144
Transmittal Number

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

Massachusetts Department of Environmental Protection

Transmittal Form for Permit Application and Payment

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

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

3. Three copies of this form will be needed.

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

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

MassDEP
P.O. Box 4062
Boston, MA
02211

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

A. Permit Information

BWP AQ03
1. Permit Code: 7 or 8 character code from permit instructions

PLAN APPLICATION MAJOR COMPREHENSIVE
2. Name of Permit Category

COMBINED HEAT AND POWER COMBUSTION TURBINE INSTALLATION
3. Type of Project or Activity

B. Applicant Information – Firm or Individual

Massachusetts Institute of Technology
1. Name of Firm - Or, if party needing this approval is an individual enter name below:

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

59 Vassar Street, Building 42C
5. Street Address

6. City/Town	7. State	8. Zip Code	9. Telephone #	10. Ext. #
Cambridge	MA	02139	617-253-4790	

Ken Packard
11. Contact Person

kpackard@MIT.EDU
12. e-mail address (optional)

C. Facility, Site or Individual Requiring Approval

Massachusetts Institute of Technology
1. Name of Facility, Site Or Individual

59 Vassar St., Building 42C
2. Street Address

3. City/Town	4. State	5. Zip Code	6. Telephone #	7. Ext. #
Cambridge	MA	02139	617-253-4790	

8. DEP Facility Number (if Known)	9. Federal I.D. Number (if Known)	10. BWSC Tracking # (if Known)
314888		1191844

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

EPSILON ASSOCIATES
1. Name of Firm Or Individual

3 CLOCKTOWER PLACE SUITE 250
2. Address

3. City/Town	4. State	5. Zip Code	6. Telephone #	7. Ext. #
MAYNARD	MA	01754	978-461-6202	

AJ Jablonowski
8. Contact Person

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

E. Permit - Project Coordination

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

F. Amount Due

DEP Use Only

Permit No:

Rec'd Date:

Reviewer:

Special Provisions:

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

Check Number	Dollar Amount	Date
	$24,305	

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

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

Comprehensive Plan Application for Fuel Utilization Emission Unit(s)

X262144
Transmittal Number

1191844
Facility ID (if known)

Use this form for:

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

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

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

A. Facility Information

Massachusetts Institute of Technology
1. Facility Name

59 Vassar St., Building 42C
2. Street Address

Cambridge
3. City

MA
4. State

02139
5. ZIP Code

314888
6. MassDEP Account # / FMF Facility # (if Known)

1191844
7. Facility AQ # / SEIS ID # (if Known)

4931/8221
8. Standard Industrial Classification (SIC) Code

611310
9. North American Industry Classification System (NAICS) Code

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

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

Table 1

Approval Number(s)/ 25% or 50% Rule/ 310 CMR 7.26 Certification	**Transmittal Number(s)** (if Applicable)	**Air Contaminant** (e.g. CO, CO2, NOx, SO2, VOC, HAP, PM or Other [Specify])*	**Existing Facility-Wide Emission Cap(s) Per Consecutive 12-Month Time Period** (Tons)
NOT APPLICABLE (FACILITY HOLDS FINAL OPERATING PERMIT TR. NO. X223574			

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

A. Facility Information (continued)

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

    If Yes, describe:

B. Equipment Description

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

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

   If Yes, list pertinent Plan Approval(s):

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

   If Yes, list pertinent Plan Approval(s): MBR-91-COM-027

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

   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.

Netting & Offsets

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

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

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

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

B. Equipment Description (continued)

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

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

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

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

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

Table 3				
Facility-Assigned Identifying Number for Proposed Equipment (Emission Unit No.)	**Description of Proposed Equipment Including Manufacturer & Model Number or Equivalent** (e.g. Acme Boiler, Model No. AB500)	**Manufacturer's Maximum Heat Input Rating in Btu/hr**	**Proposed Primary Fuel**	**Proposed Back-Up Fuel** (if Any)
CTG 200 ☒ New ☐ Modified	COMBUSTION TURBINE:GE LM2500 OR EQUAL	256,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
HRSG 200 ☒ New ☐ Modified	DUCT BURNER	134,000,000	NATURAL GAS	NONE
CTG 300 ☒ New ☐ Modified	COMBUSTION TURBINE:GE LM2500 OR EQUAL	256,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
HRSG 300 ☒ New ☐ Modified	DUCT BURNER	134,000,000	NATURAL GAS	NONE

BOILER 3 ☐ New ☒ Modified	BOILER: WICKES TYPE R	116,200,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
BOILER 4 ☐ New ☒ Modified	BOILER: WICKES TYPE R	116,200,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
BOILER 5 ☐ New ☒ Modified	BOILER: RILEY TYPE VP	145,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
BOILER 7 ☐ New ☒ Modified	BOILER: INDECK "D" TYPE	99,700,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
BOILER 9 ☐ New ☒ Modified	BOILER: NEBRASKA N2S-7S OR EQUIVALENT	125,000,000	NATURAL GAS	ULTRA LOW SULFUR DIESEL
Emergency Generator ☒ New ☐ Modified	CAT 2 MW Emergency Diesel Generator	19,320,000	ULTRA LOW SULFUR DIESEL	NONE

B. Equipment Description (continued)

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

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

Table 4

Emission Unit No.	**Burner Manufacturer & Model Number or Equivalent** (e.g. Acme Burner, Model No. AB300)	**Manufacturer's Maximum Firing Rate** (Gallons per Hour or Cubic Feet per Hour)	**Type of Burner** (e.g. Ultra Low NOx Burner)	**Is Emission Unit Equipped with Flue Gas Recirculation?**
HRSG 200	TBD	134,000 CF/HR	DUCT BURNER	☐ Yes ☒ No
HRSG 300	TBD	134,000 CF/HR	DUCT BURNER	☐ Yes ☒ No
BOILER 3	PEABODY	116,000 CF/HR	N/A	☐ Yes ☒ No
BOILER 4	PEABODY	116,000 CF/HR	N/A	☐ Yes ☒ No
BOILER 5	COEN	145,000 CF/HR	LOW NOx	☐ Yes ☒ No
BOILER 7	NATCOM	99,700 CF/HR	ULTRA LOW NOx	☒ Yes ☐ No
BOILER 9	C-B NATCOM	125,000 CF/HR	ULTRA LOW NOx	☒ Yes ☐ No

B. Equipment Description (continued)

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

Table 5		
Emission Unit No.	**Maximum Firing Rate** (Gallons per Hour or Cubic Feet per Hour)	**Maximum Output Rating** (Megawatts [MW] or Kilowatts [kW]; Indicate Unit of Measure)
CTG-200	256,000 CF/HR (GAS) 1,800 GAL/HR (USLD)	22 MW
CTG-300	256,000 CF/HR (GAS) 1,800 GAL/HR (USLD)	22 MW

Continue to Next Page ►

B. Equipment Description (continued)

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

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

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

Table 6a			
Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
SCR ☒ New ☐ Existing	CTG-200 and 300; HRSG 200 and 300	VOC	
		CO	
		PM[1]	
		NO_x	92%
		NH_3	
		Other:	

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

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

Table 6b			
Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
OXIDATION CATALYST ☒ New ☐ Existing	CTG 300 HRSG 300	VOC	50%
		CO	94-96%
		PM[1]	
		NO_x	
		NH_3	
		Other:	

Table 6c			
Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
LOW NOx BURNER ☐ New ☒ Existing	Boiler 5	VOC	
		CO	
		PM[1]	
		NO_x	
		NH_3	
		Other:	

Table 6d			
Description of Proposed PCD	**Emission Unit No(s). Served by PCD**	**Air Contaminant(s) Controlled**	**Overall Control** (Percent by Weight)
ULTRA LOW NOx BURNER ☐ New ☒ Existing	Boiler 7 and 9	VOC	
		CO	
		PM[1]	
		NO_x	
		NH_3	
		Other:	

B. Equipment Description (continued)

Supplemental Forms Required

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

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

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

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

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

Table 7			
Emission Unit No.	**Type of Noise Suppression Equipment** (e.g. Mufflers, Acoustical Enclosures)	**Equipment Manufacturer**	**Equipment Model No.**
CTG 200 and 300	Turbine Acoustical Enclosure	GE OR EQUAL	TBD
CTG 200 and 300	Turbine Inlet Air Silencer	GE OR EQUAL	TBD
CTG 200 and 300	Turbine Enclosure Intake Vent Silencer	GE OR EQUAL	TBD
CTG 200 and 300	Turbine Enclosure Discharge Vent Silencer	GE OR EQUAL	TBD

B. Equipment Description (continued)

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

*If No, explain:

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

NATURAL GAS AND ULSD FIRING, NO VISIBLE EMISSIONS EXPECTED DURING NORMAL OPERATION. VISIBLE EMISSIONS DURING STARTUPS AND SHUTDOWNS WILL BE MINIMIZED BY FOLLOWING MANUFACTURERS' STANDARD OPERATING PROCEDURES.

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

NATURAL GAS AND ULSD FIRING, NO ODORS EXPECTED

C. Stack Description

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

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

Table 8

Emission Unit No.	Stack Height Above Ground (Feet)	Stack Height Above Roof (Feet)	Stack Exit Diameter or Dimensions (Feet)	Exhaust Gas Exit Temperature Range (Degrees Fahrenheit)	Exhaust Gas Exit Velocity Range (Feet per Second)	Stack Liner Material
HRSG 200	165	102	7.0	180-225	38-74	STEEL
HRSG 300	165	102	7.0	180-225	38-74	STEEL
Emergency Generator	96.5	33.5	2.33	751.1	59.5	STEEL

Continue to Next Page ►

D. Best Available Control Technology (BACT) Emissions

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

Note: Complete a separate table for each proposed fuel to be used in each Emission Unit. For example, if one Emission Unit will be capable of burning two different fuels, you will need to complete two tables.

Table 9A						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. CTG 200 or 300; HRSG 200 or 300 Fuel Used NATURAL GAS	PM[1]	6.5 lbs/hr	6.5 lbs/hr	41.1Tons (NG & ULSD)	N/A	N/A
	$PM_{2.5}$	6.5 lbs/hr	6.5 lbs/hr	41.1 Tons (NG & ULSD)	N/A	N/A
	PM_{10}	6.5 lbs/hr	6.5 lbs/hr	41.1 Tons (NG & ULSD)	N/A	N/A
	NO_x[2]	~24 lbs/hr	3.4 lb/hr	25.4 Tons (NG & ULSD)	N/A	N/A
	CO	~100-200 lb/hr	2.6-11.3 lb/hr	21.7 Tons (NG & ULSD)	N/A	N/A
	VOC	~10-20 lb/hr	4.6-10.2 lbs/hr	15.6 Tons (NG & ULSD)	N/A	N/A
	SO_2	1.1 lbs/hr	1.1 lbs/hr	6.4 Tons (NG & ULSD)	N/A	N/A
	HAP[3]	<0.5 lb/hr	<0.5 lb/hr	<10 Tons (NG & ULSD)	N/A	N/A
	Total HAPs[3]	<1.5 lb/hr	<1.5 lb/hr	<10 Tons (NG & ULSD)	N/A	N/A
	CO_2[4]	46,401 lbs/hr	46,401 lbs/hr	333,530 Tons (NG & ULSD)	N/A	N/A

[1]PM includes particulate matter having a diameter of 10 microns or less (PM_{10}) and particulate matter having a diameter of 2.5 microns or less ($PM_{2.5}$).
[2] NO_X emissions from this proposed project need to be included for the purposes of NO_X emissions tracking for 310 CMR 7.00: Appendix A, if applicable.
[3]Operating Permit facilities are required to track emissions of Hazardous Air Pollutants.
[4]Pounds of CO_2 per unit product (e.g. pounds CO_2 per megawatt, pounds CO_2 per 1,000 pounds of steam).
[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.

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

Table 9B						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. CTG 200 or 300; HRSG 200 or 300 Fuel Used ULSD IN CTG 200 or 300, NATURAL GAS IN HRSG 200 or 300	PM	11.3 lbs/hr	11.3 lbs/hr	41.1 Tons (NG & ULSD)	N/A	177,946 MMBTU/yr ULSD per turbine
	$PM_{2.5}$	11.3 lbs/hr	11.3 lbs/hr	41.1 Tons (NG & ULSD)	N/A	N/A
	PM_{10}	11.3 lbs/hr	11.3 lbs/hr	41.1 Tons (NG & ULSD)	N/A	N/A
	NO_x	~41 lbs/hr	7.2 lbs/hr	25.4 Tons (NG & ULSD)	N/A	N/A
	CO	~36 lb/hr	5.6 lbs/hr	21.7 Tons (NG & ULSD)	N/A	N/A
	VOC	6.4 lbs/hr	6.4 lbs/hr	15.6 Tons (NG & ULSD)	N/A	N/A
	SO_2	0.8 lbs/hr	0.8 lbs/hr	6.4 Tons (NG & ULSD)	N/A	N/A
	HAP	<0.5 lbs/hr	<0.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	Total HAPs	<1.5 lbs/hr	<1.5 lbs/hr	<10 Tons (NG & ULSD)	N/A	N/A
	CO_2	57,083 lbs/hr	57,083 lbs/hr	333,530 Tons (NG & ULSD)	N/A	N/A

Continue to Next Page ►

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

Table 9C						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. Boiler 7 Fuel Used Natural Gas	PM	0.01 lb/MMBTU	0.997 lb/hr	None	N/A	N/A
	$PM_{2.5}$	0.01 lb/MMBTU	0.997 lb/hr	None	N/A	N/A
	PM_{10}	0.01 lb/MMBTU	0.997 lb/hr	None	N/A	N/A
	NO_x	0.011 lb/MMBTU	1.097 lb/hr	None	N/A	N/A
	CO	0.011 lb/MMBTU	1.097 lb/hr	None	N/A	N/A
	VOC	0.03 lb/MMBTU	2.99 lb/hr	None	N/A	N/A
	SO_2	0.0014 lb/MMBTU	0.14 lb/hr	None	N/A	N/A
	HAP	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	Total HAPs	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	CO_2	119 lb/MMBTU	11,864 lb/hr	None	N/A	N/A

Continue to Next Page ►

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

Table 9D						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. Boiler 7 Fuel Used ULSD	PM	0.01 lb/MMBTU	0.997 lb/hr	None	N/A	N/A
	$PM_{2.5}$	0.01 lb/MMBTU	0.997 lb/hr	None	N/A	N/A
	PM_{10}	0.01 lb/MMBTU	0.997 lb/hr	None	N/A	N/A
	NO_x	0.046 lb/MMBTU	4.59 lb/hr	None	N/A	N/A
	CO	0.035 lb/MMBTU	3.49 lb/hr	None	N/A	N/A
	VOC	0.03 lb/MMBTU	2.99 lb/hr	None	N/A	N/A
	SO_2	0.0015 lb/MMBTU	0.15 lb/hr	None	N/A	N/A
	HAP	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	Total HAPs	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	CO_2	166 lb/MMBTU	16,550 lb/hr	None	N/A	N/A

Continue to Next Page ►

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

Table 9E						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. Boiler 9 Fuel Used Natural Gas	PM	0.01	1.26 lb/hr	None	N/A	N/A
	$PM_{2.5}$	0.01 lb/MMBTU	1.26 lb/hr	None	N/A	N/A
	PM_{10}	0.01 lb/MMBTU	1.26 lb/hr	None	N/A	N/A
	NO_x	0.011 lb/MMBTU	1.38 lb/hr	None	N/A	N/A
	CO	0.011 lb/MMBTU; 0.033 lb/MMBTU @ <33% load	1.38 lb/hr; 4.15 lb/hr @ <33% load	None	N/A	N/A
	VOC	0.03 lb/MMBTU	3.774 lb/hr	None	N/A	N/A
	SO_2	0.0014 lb/MMBTU	0.18 lb/hr	None	N/A	N/A
	HAP	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	Total HAPs	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	CO_2	119 lb/MMBTU	14,970 lb/hr	None	N/A	N/A

Continue to Next Page ►

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

Table 9F						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. Boiler 9 Fuel Used ULSD	PM	0.03 lb/MMBTU	3.58 lb/hr	None	N/A	N/A
	$PM_{2.5}$	0.03 lb/MMBTU	3.58 lb/hr	None	N/A	N/A
	PM_{10}	0.03 lb/MMBTU	3.58 lb/hr	None	N/A	N/A
	NO_x	0.1 lb/MMBTU	11.92 lb/hr	None	N/A	N/A
	CO	0.035 lb/MMBTU	4.17 lb/hr	None	N/A	N/A
	VOC	0.03 lb/MMBTU	3.58 lb/hr	None	N/A	N/A
	SO_2	0.0016 lb/MMBTU	0.19 lb/hr	None	N/A	N/A
	HAP	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	Total HAPs	<0.5 lb/hr	<0.5 lb/hr	None	N/A	N/A
	CO_2	166 lb/MMBTU	19,787 lb/hr	None	N/A	N/A

Continue to Next Page ►

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

Table 9G						
Emission Unit No. & Fuel Used	**Air Contaminant**	**Uncontrolled Emissions** (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O_2 or CO_2])	**Proposed BACT Emissions** (lbs/hr, lb/MMBtu or ppmvd@ %O_2 or CO_2)	**Proposed Consecutive 12-Month Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Monthly Time Period Emissions Restrictions** (Tons, if Any)[5]	**Proposed Fuel Usage Limit(s)** (if Any)[5]
Unit No. Emergency Generator Fuel Used ULSD	PM	0.4 lb/hr	0.4 lb/hr	0.06 tpy	N/A	N/A
	$PM_{2.5}$	0.4 lb/hr	0.4 lb/hr	0.06 tpy	N/A	N/A
	PM_{10}	0.4 lb/hr	0.4 lb/hr	0.06 tpy	N/A	N/A
	NO_x	35.09 lb/hr	35.09 lb/hr	5.27 tpy	N/A	N/A
	CO	2.2 lb/hr	2.2 lb/hr	0.33 tpy	N/A	N/A
	VOC	1.13	1.13	0.17 tpy	N/A	N/A
	SO_2	0.029 lb/hr	0.029 lb/hr	0.0044 tpy	N/A	N/A
	HAP	<0.1 lb/hr	<0.1 lb/hr	<0.01 tpy	N/A	N/A
	Total HAPs	<0.1 lb/hr	<0.1 lb/hr	<0.01 tpy	N/A	N/A
	CO_2	3184 lb/hr	3184 lb/hr	477.6	N/A	N/A

Note: Top-Case BACT is the emission rate identified via the MassDEP BACT Guidance or a pre-application meeting with MassDEP.

2. Are proposed BACT emission limits in the tables above Top-Case BACT as referenced in 310 CMR 7.02(8)(a)2.a? ☒ Yes ☐ No*

*If No, you must submit form BWP AQ BACT to demonstrate that this project meets BACT as provided in 310 CMR 7.02(8)(a)2 or 310 CMR 7.02(8)(a)2.c..

Continue to Next Page ►

E. Monitoring Procedures

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

Table 10			
Emission Unit No.	**Type or Method of Monitoring** (e.g. CEMS[1], Fuel Flow)	**Parameter/Emission Monitored**	**Frequency of Monitoring**
CTG 200 and 300, HRSG 200 and 300	CEMS	NOx, CO, NH3	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	FUEL FLOW	NATURAL GAS AND ULSD USAGE	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	COMS	OPACITY	6-MINUTE AVERAGES

[1] CEMS = Continuous Emissions Monitoring System

F. Record Keeping Procedures

Complete the table below to summarize the details of the proposed project's record keeping procedures. Proposed record keeping procedures need to be able to demonstrate your compliance status with regard to all limitations/restrictions proposed herein. Record keeping may include, but is not limited to, hourly or daily logs, meter charts, time logs, fuel purchase receipts, CEMS records, etc.

Table 11			
Emission Unit No.	**Parameter/Emission** (e.g. Temperature, Material Usage, Air Contaminant)	**Record Keeping Procedures** (e.g. Data Logger or Manual)	**Frequency of Data Record** (e.g. Hourly, Daily)
CTG 200 and 300, HRSG 200 and 300	CEMS	NOx, CO, NH3	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	FUEL FLOW	NATURAL GAS AND ULSD USAGE	AVERAGED HOURLY
CTG 200 and 300, HRSG 200 and 300	COMS	OPACITY	6-MINUTE AVERAGES

Examples of emissions calculations for record keeping purposes:

NOx: {(0.085 pounds per 1,000,000 British thermal units (MMBtu)*(**X** cubic feet)*(1,000 Btu per cubic feet) + (0.10 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon)}* 1 ton per 2000 pounds = NOx in tons per consecutive twelve month time period

CO: {(0.035 pounds per MMBtu)*(**X** cubic feet)*(1000 Btu per cubic feet) + (0.035 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon}*1 ton per 2000 pounds = CO in tons per consecutive twelve month time period

VOC: {(0.035 pounds per MMBtu)*(**X** cubic feet)*(1000 Btu per cubic feet) + (0.035 pounds per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon}*1 ton per 2000 pounds= VOC in tons per consecutive twelve month time period

SO_2: {(0.0015 lb per MMBtu)*(**Y** gallons of fuel oil)*(130,000 Btu per gallon)}*1 ton per 2000 pounds = SO_2 in tons per consecutive twelve month time period

Where: **X** = cubic feet of natural gas burned per consecutive twelve month time period
Y = gallons of ULSD oil burned per consecutive twelve month time period

G. Additional Information Checklist

Attach a specific facility description and the following required additional information that MassDEP needs to process your application. Check the box next to each item to ensure that your application is complete.

- ☒ Plot Plan
- ☒ Combustion Equipment Manufacturer Specifications, Including but not Limited to Emissions Data
- ☐ Combustion Equipment Standard Operating Procedures *[TO BE PROVIDED AT A LATER DATE]*
- ☐ Combustion Equipment Standard Maintenance Procedures, Including Cleaning Method & Frequency *[TO BE PROVIDED AT A LATER DATE]*
- ☒ Calculations to Support This Plan Application
- ☐ Air pollution control device manufacturer specifications, if applicable *[TO BE PROVIDED AT A LATER DATE]*
- ☐ Air pollution control device standard operating procedures, if applicable *[TO BE PROVIDED AT A LATER DATE]*
- ☐ Air pollution control device standard maintenance procedures, if applicable *[TO BE PROVIDED AT A LATER DATE]*
- ☐ BWP AQ BACT Form, if not proposing Top-Case BACT *[NOT APPLICABLE]*
- ☒ Air quality dispersion modeling demonstration documenting that National Ambient Air Quality Standards (NAAQS) are not exceeded
- ☒ Process flow diagram for the proposed equipment and any PCD, if applicable, including relevant parameters (e.g. flow rate, pressure and temperature)

Note: Pursuant to 310 CMR 7.02(5)(c), MassDEP may request additional information.

Continue to Next Page ►

H. Other Regulatory Considerations

Indicate below whether the proposed project is subject to any additional regulatory requirements.

310 CMR 7.00: Appendix A Nonattainment Review, or is netting used to avoid review under 310 CMR 7.00 Appendix A or 40 CFR 52.21? ☐ Yes ☒ No

40 CFR 60: New Source Performance Standards (NSPS)? ☒ Yes ☐ No

If Yes: Which subpart? **KKKK and IIII** Applicable emission limitation(s): **See Application Report Section 3.4**

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

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

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

If Yes: Which subpart? **ZZZZ** Applicable emission limitation(s): **See NSPS IIII**

[After approval, Boilers 3, 4, 5, 7, and 9 will no longer be subject to subpart JJJJJJ]

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

If Yes: EOEA No.: **TBD**

Other Applicable Requirements? ☐ Yes ☒ No

If Yes: Specify:

Facility-Wide Potential-to-Emit Hazardous Air Pollutants (HAPS): ☐ Major* ☒ Non-Major

*A Major source has a facility-wide potential-to-emit of 25 tons per year or more of the sum of all hazardous air pollutants or 10 tons per year or more of any individual hazardous air pollutant.

Continue to Next Page ►

I. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

A.J. Jablonowski
P.E. Name (Type or Print)

P.E. Signature

PRINCIPAL
Position/Title

EPSILON ASSOCIATES, INC.
Company

12/11/2015
Date (MM/DD/YYYY)

39123
P.E. Number

COMMONWEALTH OF MASSACHUSETTS
ANDREW JABLONOWSKI
CHEMICAL
No. 39123
REGISTERED PROFESSIONAL ENGINEER

J. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

William C. VanSchalkwyk
Responsible Official Name (Type or Print)

Responsible Official Signature

Managing Director, EHS Programs
Responsible Official Title

Massachusetts Institute of Technology
Responsible Official Company/Organization Name

12/14/2015
Date (MM/DD/YYYY)

K. Energy Efficiency Evaluation Survey

1. Do you know where your electricity and/or fuel and/or water and/or heat and/or compressed air is being used/consumed? ☒ Yes ☐ No

2. Has your facility had an energy audit performed by your utility supplier (or other) in the past two years?[1] ☒ Yes ☐ No

   a. Did the audit include evaluations for heat loss, lighting load, cooling requirements and compressor usage? ☒ Yes ☐ No

   b. Did the audit influence how this project is configured? ☒ Yes ☐ No

3. Does your facility have an energy management plan? ☒ Yes ☐ No

   a. Have you identified and prioritized energy conservation opportunities? ☒ Yes ☐ No

   b. Have you identified opportunities to improve operating and maintenance procedures by employing an energy management plan? ☒ Yes ☐ No

4. Has each emission unit proposed herein been evaluated for energy consumption including average and peak electrical use; efficiency of electric motors and suitability of alternative motors such as variable speed; added heat load and/or added cooling load as a result of the operation of the proposed process; added energy load due to building air exchange requirements as a result of exhausting heat or emissions to the ambient air; and/or use of compressors? ☒ Yes ☐ No

5. Has your facility considered alternative energy methods such as solar, geothermal or wind power as a means of supplementing all or some of the facility's energy demand? ☒ Yes ☐ No

6. Does your facility comply with Leadership in Energy & Environmental Design (LEED) Green Building Rating System design recommendations?[2] ☒ Yes ☐ No

[1]A facility wide energy audit would include an inspection of such things as lighting, air-conditioning, heating, compressors and other energy-demand equipment. It would also provide you with information on qualifying equipment rebates and incentive programs; analysis of your energy consumption patterns and written cost-savings recommendations and estimated cost savings for installing new, high-efficiency equipment.

[2]To understand the LEED Rating System, it is important to become familiar with its comprising facets. To be considered for LEED New Construction and Major Renovations, a building must meet specific prerequisites and additional credit areas within six categories:

- Sustainable Sites
- Materials and Resources
- Water Efficiency
- Indoor Environmental Quality
- Energy and Atmosphere
- Innovation and Design

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

BWP AQ Selective Catalytic Reduction

Submit with Form CPA-FUEL and/or CPA-PROCESS whenever construction, substantial reconstruction or alteration of a Selection Catalytic Reduction system is proposed unless exempt per 310 CMR 7.02(2)(b).

X262144
Transmittal Number

1191844
Facility ID (if known)

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

A. Inlet Operating Conditions

1. Complete the table below with information on inlet gas flow(s).

Table 1a			
Emission Unit No(s). Being Controlled	**Average Inlet Gas Flow** (Actual Cubic Feet Per Minute)	**Inlet Temperature** (Degrees Fahrenheit (^{o}F))	**Moisture Content in the Inlet** (Pounds Per Minute)
CTG 200 or 300 HRSG 200 or 300	~246,000 ACFM	~538 F	~58 Pounds Per Minute
Totals:			

2. Which metals/elements are present in gas stream?

☐ Potassium ☐ Arsenic ☐ Lead
☐ Zinc ☐ Sodium ☐ Phosphorus

3. Are there any other catalyst binding agents present in the gas stream?

☐ Yes – Describe Below ☒ No

TRACE CATALYST BINDING AGENTS IN NATURAL GAS AND ULSD.

4. Complete the table below to provide the maximum oxides of nitrogen (NOx) emissions:

Table 2		
Emission Unit No(s). Being Controlled	**Inlet NOx** (Pounds Per Hour)	**Inlet NOx** (Parts Per Million by Volume, Dry Basis)
CTG 200 or 300	23.6 LBS/HOUR	~25 PPM @ 15% O2
HRSG 200 or 300	18.5 LBS/HOUR	~0.14 LBS/MMBTU

Continue to Next Page ►

BWP AQ Selective Catalytic Reduction

Submit with Form CPA-FUEL and/or CPA-PROCESS whenever construction, substantial reconstruction or alteration of a Selection Catalytic Reduction system is proposed unless exempt per 310 CMR 7.02(2)(b).

X262144
Transmittal Number

1191844
Facility ID (if known)

B. Specifications

1. Manufacturer of Selective Catalytic Reduction (SCR) system: To be Determined
   Company
2. Model Number (or Equivalent): To be Determined
   Number
3. Location of SCR unit relative to other pieces of equipment: ☐ High Dust ☒ Low Dust ☐ Tail End
4. Information about the catalyst used:
   a. Description of catalyst: TBD
   Description
   b. Operating temperature range of catalyst: from 500 to 575
   Degrees Fahrenheit (°F) Degrees Fahrenheit (°F)
   c. Pressure drop across the catalyst: ~3.0
   Inches of Water

5a. Number of catalyst layers the system can accommodate: TBD
Number

5b. Number of catalyst layers that will be installed: TBD
Number

6. Does the SCR system employ a guard bed for catalyst protection? ☐ Yes ☒ No*

   *If No, explain:

   NATURAL GAS AND ULSD FIRED

7. Expected catalyst life: 10 years
   Years
8. Operating hours per layer of catalyst: TBD
   Hours
9. Can the catalyst be reactivated? ☐ Yes * ☐ No

   *If Yes, describe how:

   TBD

10. Catalyst cleaning method: ☐ Compressed Air Soot Blower ☐ Steam Soot Blower ☐ Sonic Horns ☒ Other – Describe: PERIODIC OFFLINE CLEANING
11. Describe SCR system dust management technologies and strategies being used, if any (e.g. ash screens):

    NONE NEEDED, NATURAL GAS AND ULSD FIRED.

B. Specifications (continued)

12. Are you proposing a by-pass stack? ☐ Yes * ☒ No

*If Yes, describe:

C. Description of Reducing Agent

1. Type and form of reducing agent proposed: ☐ Gaseous ☐ Liquid ☐ Anhydrous Ammonia ☐ Aqueous Ammonia ☐ Urea ☒ Other – Describe: AMMONIA GENERATED FROM UREA ONSITE.
2. If liquid, provide weight percent in solution: UREA SOLUTION 40% IN WATER
   Weight Percent
3. Method of reducing agent injection: ☐ Direct Injection ☒ Injection Grid
4. Describe in detail how the concentration and usage rate of the reducing agent were determined. Continue on a separate attachment, if necessary.
   CONCENTRATION BASED ON EXISTING UREA TO AMMONIA CONVERSION SYSTEM.

   UREA USAGE RATE BASED ON MASS BALANCE
5. Describe the process controls for proper mixing of the reducing agent in the gas stream. Continue on a separate attachment, if necessary.
   SPRAY INJECTORS WILL BE USED TO MIX UREA WITH HEATED AIR. UREA WILL DECOMPOSE, GENERATING AMMONIA. AMMONIA INJECTION GRID WILL BE INSTALLED UPSTREAM OF SCR CATALYST, MIXING AMMONIA WITH EXHAUST GAS.
6. Describe storage of the reagent, including details about any storage containment (e.g. dimension of berms, evaporative mitigation). Continue on a separate attachment, if necessary.
   STORAGE OF UREA IN CONTAINED TANK AT AMBIENT CONDITIONS. AMMONIA GENERATED AS NEEDED.
7. Is the reagent subject to 42 U.S.C. 7401, Section 112(r)? ☐ Yes * ☒ No

   *If Yes, attach a copy of the Risk Management Plan to this form.
8. You MUST attach to this form a copy of an analysis of possible impacts to off-property locations from a catastrophic release of the reducing agent, in comparison with American Industrial Hygiene Association Emergncy Response Planning Guidelines.

Not applicable.

D. Emissions Data

1. Complete the table below to provide maximum oxides of nitrogen (NOx) and ammonia (NH_3) slip concentrations and emission rates:

Table 3		
Air Contaminant	**Outlet** (Pounds Per Hour)	**Outlet**[1] (Parts Per Million By Volume, Dry Basis)
NOx	3.47 lb/hr (FIRING NG) 10.14 lb/hr (FIRING ULSD)	2.0 (Firing NG) 9.0 (Firing ULSD)
NH_3	1.6 lb/hr	2.0

[1]Boilers at 3% oxygen; combustion turbines at 15% oxygen; engines at 15% oxygen.

2. Explain how the above NOx and NH_3 emissions data were obtained. Attach appropriate calculations and documentation.

SEE BACT ANALYSIS IN APPLICATION TEXT, AND APPENDIX C FOR CALCULATIONS.

E. Drawing of Selective Catalytic Reduction System

You must attach to this form a schematic drawing of the proposed Selective Catalytic Reduction system. At a minimum, it must show the location(s) of the catalyst bed(s), bypass damper(s) if applicable, bypass stack if applicable, and normal stack. Sampling ports for emissions testing must also be shown.
[BMcD]

Note: You must notify the BWP Compliance & Enforcement Chief in the appropriate MassDEP regional office by telephone as soon as possible, within but no later than one (1) business day after you discover any upset or malfunction to facility equipment that results in excess emissions to the air and/or a condition of air pollution. You must submit written notice within seven (7) days thereafter.

F. Monitoring, Record Keeping & Failure Notification

1. Provide the manufacturer, make and model number of the proposed continuous emissions and opacity monitoring systems:

TBD

2. Identify the air contaminants that will be continuously monitored and recorded (e.g. NOx, NH_3, opacity)

NOX, NH3

3. Describe any proposed process monitors (e.g. ammonia injection, fuel combustion) and frequency of data recording:

FUEL COMBUSTION, UREA FLOWRATE, NOx CONCENTRATION, INLET SCR CATALYST TEMP, AND SCR CATLYST PRESSURE DROP. FREQUENCY OF DATA RECORDING TBD

F. Monitoring, Record Keeping & Failure Notification (continued)

4. Are there any alarms associated with the monitoring equipment? ☒ Yes – Complete Table 4 ☐ No – Explain Below

Table 4			
Operating Parameter Monitored	**Describe Alarm Trigger**	**Monitoring Device or Alarm Type**	**Does the Alarm Initiate an Automated Response?**
NOX	TBD	☐ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe: TBD	☐ Yes ☐ No If Yes, Describe: TBD
NH3	TBD	☐ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe: TBD	☐ Yes ☐ No If Yes, Describe: TBD
		☐ Visual ☐ Auditory ☐ Automatic (Remote Monitoring) ☐ Other – Describe:	☐ Yes ☐ No If Yes, Describe:

5. Describe the operating conditions that are monitored to determine the reducing agent injection rate:

   NOx EMISSION RATE AND FUEL FIRING RATE

6. How often will the catalyst be tested and by what test method (e.g. core sample)?

   TESTING IS RECOMMENDED TO BE PERFORMED ANNUALLY. THE TEST ELEMENTS FROM THE SCR CAN BE REMOVED AND SENT TO THE CATALYST VENDOR OR A THIRD PARTY.

7. List and explain all of the operating and safety controls associated with the SCR system. Continue on a separate attachment, if necessary.

   OPERATING TEMPERATURE & PRESSURE SENSORS, FUEL AND UREA FLOW MONITORS, STACK NOx AND NH3 CEMS.

8. List the SCR system emergency procedures to be used during system upsets. Continue on a separate attachment, if necessary.

   MANUAL ADJUSTMENT OF UREA FLOW, AND LOAD REDUCTION IF NEEDED.

F. Monitoring, Record Keeping & Failure Notification (continued)

9. Explain the typical fluctuations in SCR system operation, such as changes in effluent temperatures, flow rates, pollutant concentrations, etc., which may affect operation of the unit. Also explain the means by which control efficiency will be maintained throughout these fluctuations. Continue on a separate attachment, if necessary.

Typical fluctuations include startup, shutdown, and load changes. Control efficiency is maintained through a control system that continuously monitors urea flow, NH3 slip, NOx emissions, and system temperatures and measures at different points. Controls are automated with manual operator override available.

10. Describe the record keeping procedures to be used in identifying the cause, duration and resolution of each system failure/emission(s) exceedance. Continue on a separate attachment, if necessary.

Operations and maintenance logs will be used to track system upsets, and operations & emissions data will be maintained electronically. Emissions exceedances will be reported per the operating permit requirements. This report will include the deviation, including those attributable to upset conditions, the probable cause of the deviation, and the corrective actions or preventative measures taken.

11. How will the SCR system be designed so as to allow for emissions testing using MassDEP-sanctioned test methods?

The exhaust system will have sufficient straight runs to allow installation of CEMS and stack test ports per USEPA Method 1. I

G. Standard Operating & Maintenance Procedures

Attach to this form the standard operating and maintenance procedures for the proposed Selective Catalytic Reduction system, as well as a list of the spare parts inventory that you will maintain on site, as recommended by the equipment vendor. **TO BE PROVIDED AT A LATER DATE.**

Continue to Next Page ►

H. Professional Engineer's Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

AJ Jablonowski
P.E. Name (Type or Print)

P.E. Signature

PRINCIPAL
Position/Title

EPSILON ASSOCIATES
Company

12/11/2015
Date (MM/DD/YYYY)

39123
P.E. Number

I. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

William VanSchalkwyk
Responsible Official Name (Type or Print)

Responsible Official Signature

Managing Director, EHS Programs
Responsible Official Title

Massachusetts Institute of Technology
Responsible Official Company/Organization Name

12/14/2015
Date (MM/DD/YYYY)

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.

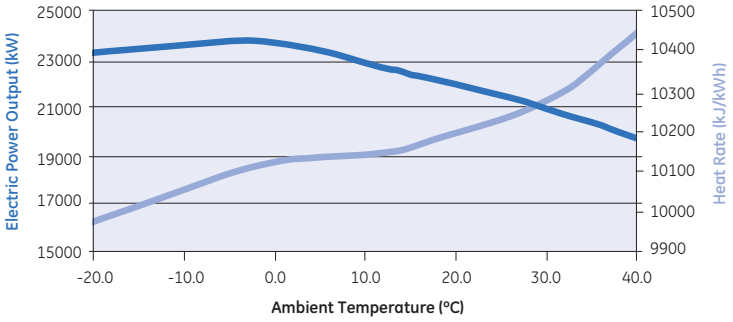
Service

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:

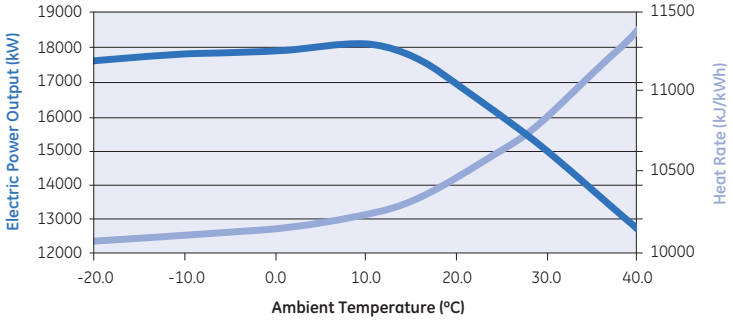
- Level IV Service Centers and overhaul capability in Houston, Texas and Rheden, the Netherlands.
- Conversions, Modifications and Upgrades (CM&Us) designed to enhance the efficiency, power output, and reliability of the LM2500. Examples include Exhaust Flow Enhancer, Wet/Dry Low Emissions (DLE) Upgrades, 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.

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

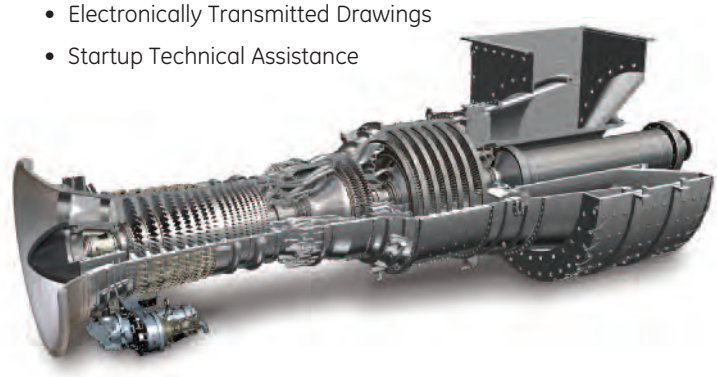
- Digital control system with a Human Machine Interface (HMI)
- 10-minute start capability to full load
- Black start
- Continuous emission monitoring
- Remote monitoring and diagnostics
- Remote display
- Control house
- Motor control center

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

Copyright © 2013 General Electric Company. All rights reserved.

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 m³/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 m³/min	6550.9 cfm
Exhaust System		
Exhaust stack gas temperature	400.1 ° C	752.2 ° F
Exhaust gas flow rate	433.1 m³/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	**COMBUSTION:**	DI
ENGINE POWER (BHP):	2,937	**ENGINE SPEED (RPM):**	1,800
GEN POWER WITH FAN (EKW):	2,000.0	**HERTZ:**	60
COMPRESSION RATIO:	14.7	**FAN POWER (HP):**	114.0
APPLICATION:	PACKAGED GENSET	**ASPIRATION:**	TA
RATING LEVEL:	STANDBY	**AFTERCOOLER TYPE:**	ATAAC
PUMP QUANTITY:	2	**AFTERCOOLER CIRCUIT TYPE:**	JW+OC, ATAAC
FUEL TYPE:	DIESEL	**INLET MANIFOLD AIR TEMP (F):**	122
MANIFOLD TYPE:	DRY	**JACKET WATER TEMP (F):**	210.2
GOVERNOR TYPE:	ADEM3	**TURBO CONFIGURATION:**	PARALLEL
ELECTRONICS TYPE:	ADEM3	**TURBO QUANTITY:**	4
CAMSHAFT TYPE:	STANDARD	**TURBOCHARGER MODEL:**	GTA5518BN-56T-1.12
IGNITION TYPE:	CI	**CERTIFICATION YEAR:**	2006
INJECTOR TYPE:	EUI	**CRANKCASE BLOWBY RATE (FT3/HR):**	2,937.9
FUEL INJECTOR:	2664387	**FUEL RATE (RATED RPM) NO LOAD (GAL/HR):**	13.7
REF EXH STACK DIAMETER (IN):	12	**PISTON SPD @ RATED ENG SPD (FT/MIN):**	2,244.1
MAX OPERATING ALTITUDE (FT):	3,117		

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]

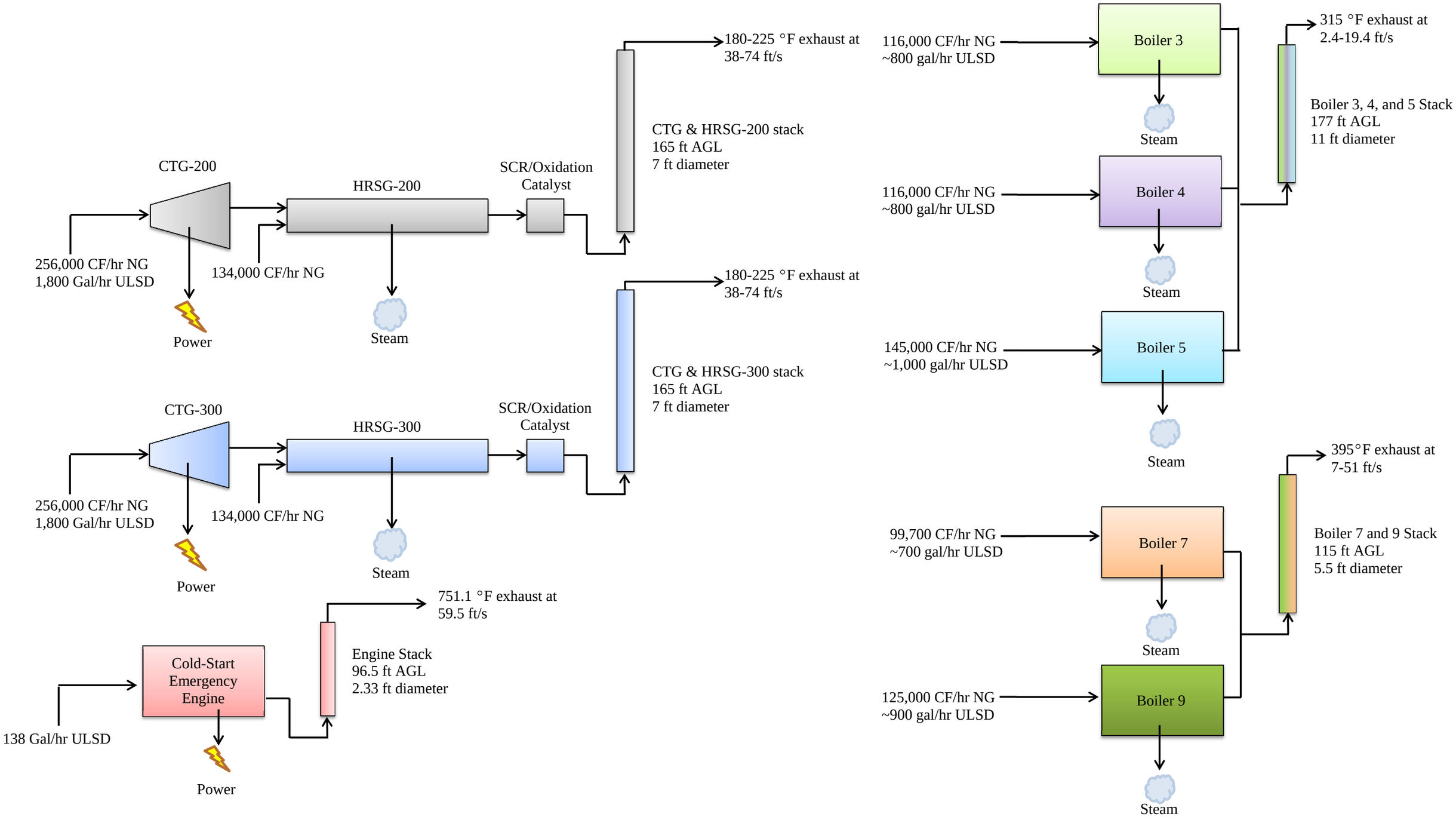
Emissions Data

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


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

4.0 BACT ANALYSIS

Boiler #9 will meet MassDEP BACT through the use of clean fuels and clean combustion. Details are described in this Section.

4.1 Best Achievable Control Technology (BACT) Requirement

BACT is defined in the 310 CMR 7.00 as,

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

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

The MassDEP has a lengthy history of determining BACT for combustion sources, and is drafting guidance for "top-case BACT" guidelines for combustion sources. Based on informal consultation with MassDEP and review of a draft of the upcoming guidance, MIT believes the proposed Boiler #9 emission rates meet top-case BACT for each pollutant, with the exception of particulate matter. For pollutants where top-case BACT is proposed, a detailed, exhaustive top-down analysis would be "reinventing the wheel" and is not included in this air plan approval application. Because of the uncertainties introduced by the inclusion of condensable particulate in the PM/PM10/PM2.5 emission rates, a formal top-down analysis is presented. Some additional documentation is also provided to confirm that the proposed CO emission rate for low-load natural gas firing, and the NOx emission rate for ULSD firing, meet top-case BACT. Carbon dioxide (CO2) BACT is also addressed.

4.2 Proposed Top-Case BACT

MIT proposes the following emission limitations and control techniques as top-case BACT:

Table 4-1 Proposed Top-Case BACT

Pollutant	Emission Limitations	Control Techniques
Nitrogen Oxides	0.011 lb/MMBtu firing gas; 0.10 lb/MMBtu firing ULSD; 6.30 tons per 12-month rolling period.	Clean fuels (natural gas and ULSD), ultra-low NOx burner, flue gas recirculation, operating hours restriction.
Carbon Monoxide	0.011 lb/MMBtu firing gas at 33% load or above, 0.033 lb/MMBtu firing gas below 33% load; 0.035 lb/MMBtu firing ULSD; 3.49 tons per 12-month rolling period.	Clean fuels (natural gas and ULSD), good combustion, operating hours restriction.
Volatile Organic Compounds	0.03 lb/MMBtu firing gas; 0.03 lb/MMBtu firing ULSD; 6.30 tons per 12-month rolling period.	Clean fuels (natural gas and ULSD), good combustion, operating hours restriction.
Sulfur Dioxide	0.0014 lb/MMBtu firing gas; 0.0015 lb/MMBtu firing ULSD; 0.32 tons per 12-month rolling period.	Clean fuels (natural gas and ULSD), good combustion, operating hours restriction.

The proposed operating hours restriction is: operation on all fuels shall not exceed 3600 hours per twelve month rolling period. Operation of Boiler #9 utilizing ULSD shall be restricted to a total of 720 hours per twelve month rolling period. This is consistent with the prior restriction for Boiler #8, except that MIT now proposes to use ULSD rather than Red dye No.2 distillate fuel oil, and MIT does not propose any restriction on firing at the same time as the other equipment in the CUP.

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.

---

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.

4.4 BACT for CO firing Natural Gas at Low Loads

Modern combustion burners, especially ultra-low-NOx burners, are carefully tuned to balance between keeping a low flame temperature and ensuring complete combustion. At low operating load (below 33% load) firing natural gas, some increase in the CO emission concentration can occur. The mass emission rate of CO remains below the full load CO mass emission rate. Post-combustion control (an oxidation catalyst) is unlikely to provide significant benefit because the temperature profile would not promote good catalyst operation, and the CO mass loading is small. Boiler 9 is unlikely to operate at reduced loads, but MIT requests the flexibility to do so to meet steam demands if needed. Given the low likelihood of low-load operation, the low mass emission rate, and the likely ineffectiveness of post-combustion control, MIT proposes a low-load CO emission limit of 0.033 lb/MMBtu as BACT.

4.5 BACT for NOx firing ULSD

Based on past experience with NOx control from package boilers, available top-case control technologies are: the use of ultra-low-NOx burners; or the use of selective catalytic reduction (SCR). SCR is a post-combustion technology where ammonia is introduced into the exhaust gas in the presence of a catalyst to reduce NOx to elemental nitrogen. The use of SCR creates issues, specifically: chemical handling (ammonia); space constraints; efficiency losses (system back-pressure); ammonia slip (unreacted ammonia emissions); and cost.

Given the limited difference between uncontrolled and controlled emission rates, the proposed operating hours limitations, the incremental cost of control for SCR use is high on a dollars-per-ton basis. Control costs are about $50,000 per ton when applied to a baseline case of low-NOx burners, and about $80,000 per ton when applied to the proposed case of ultra-low-NOx burners. This high cost of control, coupled with the energy and environmental impacts associated with SCR use, means that SCR use does not represent BACT for this application. Control cost calculations are provided in Appendix C.

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;

---

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

Air Quality Dispersion Modeling Analysis

New 44 MW CoGen Project

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
Building NE49, 2nd Floor
600 Technology Square
Cambridge, MA 02139

Prepared by:

Epsilon Associates, Inc.
3 Clock Tower Place, Suite 250
Maynard, MA 01754

December, 2015

TABLE OF CONTENTS

D-1. INTRODUCTION D-1-1

D-2. REGULATORY REQUIREMENTS D-2-1
D-2.1 Applicable Air Quality Standards, Significant Emission Rates, Significant Impact Levels, and PSD Increments D-2-1

D-3. PROJECT DESCRIPTION D-3-1
D-3.1 Project Location D-3-1
D-3.2 Facility Description D-3-1
D-3.3 Source Data D-3-2
D-3.4 Urban/Rural Analysis D-3-14
D-3.5 Background Air Quality Data D-3-17
D-3.5.1 Justification to use SILs D-3-19
D-3.6 Good Engineering Practice Stack Height Determination D-3-19

D-4. AIR QUALITY IMPACT ANALYSES D-4-1
D- 4.1 Modeling Methodology D-4-1
D- 4.2 Air Quality Model Selection and Options D-4-3
D-4.2 Meteorological Data for Modeling D-4-6
D-4.3 Receptor Grid D-4-7

D-5. AIR QUALITY IMPACT RESULTS D-5-1
D-5.1 Turbine Load Analysis D-5-1
D-5.2 Significant Impact Level Analysis D-5-1
D-5.3 National Ambient Air Quality Analysis D-5-2
D-5.3.1 MIT Sources D-5-3
D-5.3.2 Cumulative Impact Modeling D-5-5
D-5.4 Non-Criteria Pollutant Modeling D-5-8
D-5.5 PSD Increment Modeling D-5-10
D-5.6 Class I Visibility Analysis D-5-14
D-5.7 Effects on Soils and Vegetation Analyses D-5-16
D-5.8 Growth D-5-16
D-5.9 Environmental Justice D-5-17

D-6. REFERENCES D-6-1

ATTACHMENT A D-A-1

ATTACHMENT B D-B-1

ATTACHMENT C D-C-1

ATTACHMENT D D-D-1

LIST OF FIGURES

Figure D-1 – Aerial Locus Map D-3-3
Figure D-2 – Project Layout/Site Plan D-3-4
Figure D-3 – Existing Cooling Tower Locations D-3-5
Figure D-4 – Final Build Cooling Tower Locations D-3-6
Figure D-5 – USGS Topographic Map with 3 km Radius D-3-16
Figure D-6 – Building Footprints and Heights used in BPIP-Prime D-3-21
Figure D-7 – 5-Year (2009-2013) Wind Rose of Measurements from Boston Logan Airport NWS Station D-4-8
Figure D-8 – Nested Receptor Grid used in AERMOD Modeling D-4-10
Figure D-9 – Environmental Justice 2010 Populations D-5-19

LIST OF TABLES

Table D-1. CoGen Project Future Potential Emissions vs. Significant Emission Rates..... D-2-1
Table D-2. National and Massachusetts Ambient Air Quality Standards, SILS, & PSD Increments D-2-3
Table D-3. Key Existing Equipment Operating at the MIT CUP..... D-3-1
Table D-4. Operational Scenarios D-3-7
Table D-5. Physical Stack Characteristics for the New Sources D-3-7
Table D-6. New Turbine Source Characteristics and Emission Rates for 1 Turbine with Duct Burner/HRSG (Operational Scenario 1) D-3-8
Table D-7. New Turbine Source Characteristics and Emission Rates for 2 Turbines with Duct Burners/HRSGs (Operational Scenario 2) D-3-9
Table D-8. New Turbine Source Characteristics and Emission Rates for 1 Turbine through Bypass Stack (Operational Scenario 3) D-3-10
Table D-9. New 2 MW Engine and Cooling Tower Source Characteristics and Emission Rates..... D-3-11
Table D-10. Physical Stack Characteristics for the MIT Existing Sources D-3-12
Table D-11. Worst-case Operating Conditions for Existing MIT Stacks by Pollutant and Averaging Period..... D-3-13
Table D-12. Existing MIT Source Characteristics and Emission Rates D-3-15
Table D-13. Identification and Classification of Land Use..... D-3-17
Table D-14. Observed Ambient Air Quality Concentrations and Selected Background Levels..... D-3-19
Table D-15. Comparison of the Difference between the Monitored Air Quality Concentrations and the NAAQS to the Significant Impact Levels..... D-5-1
Table D-16. Proposed Project AERMOD Modeled Results for Operational Scenarios 1-3 compared to Significant Impact Levels (SILs)..... D-5-4

LIST OF TABLES (CONTINUED)

Table D-17. AERMOD Model Results for the Full MIT Facility for Operational Scenarios 1, 2 and-3 Compared to the NAAQS D-5-7
Table D-18. AERMOD Model Results for the Full MIT Facility with Interactive Sources for Operational Scenarios 1-3 Compared to the NAAQS D-5-9
Table D-19. Non-Criteria Pollutant Modeled Concentrations from CoGen Project Combustion Sources for Comparison to Massachusetts' AALs and TELs D-5-12
Table D-20. $PM_{2.5}$ and PM_{10} Emission Rates used in PSD Increment Modeling.....D-5-13
Table D-21. AERMOD Model Results for Operational Scenarios 1-3 compared to PSD Increments D-5-14
Table D-22. Class I Visibility Modeling Results -Maximum Visual Impacts Inside the Class I Area D-5-16
Table D-23 Population-weighted Predicted Impacts D-5-17

D-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 22 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.

This report describes the air quality modeling analysis performed as part of the MassDEP plan approval program. The air quality analyses described in this report demonstrate that the proposed project will not violate the National Ambient Air Quality Standards (NAAQS), Massachusetts Ambient Air Quality Standards (MAAQS), PSD increments, and other applicable federal and state regulations.

The remainder of this report is organized in five sections. Section D-2 describes the federal and state air quality regulations applicable to the modeling analysis and presents the applicable air quality standards. Section D-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 D-4 describes the air quality modeling methodology and the modeling results are presented in Section D-5. Finally, Section D-6 lists the reference documents used in compiling this modeling report.

D-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.

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

Table D-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 D-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 1997 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 10th, 2001 by a PSD application from Kendall Station.

Table D-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 D-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 D-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.

D-3. PROJECT DESCRIPTION

D-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 D-1. The proposed new turbine building and the proposed site for the new turbine stacks and new 2 MW engine stack are shown.

D-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 D-3.

Table D-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 (BLR-42-9)
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 D-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 D-3 shows the locations of the existing cooling towers, and the cooling tower configuration once the project is built is shown in Figure D-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.

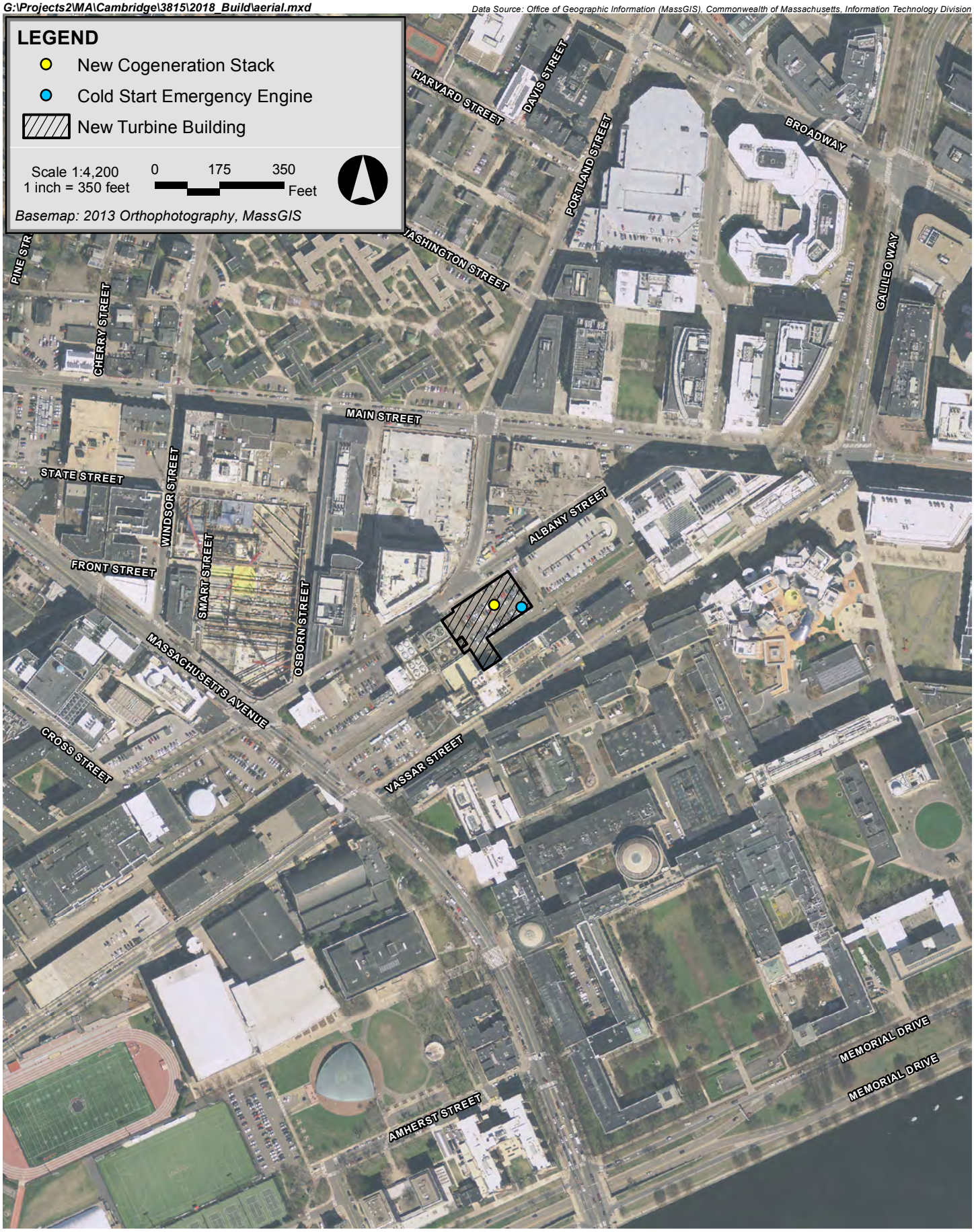
D-3.3 Source Data

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 D-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.

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

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

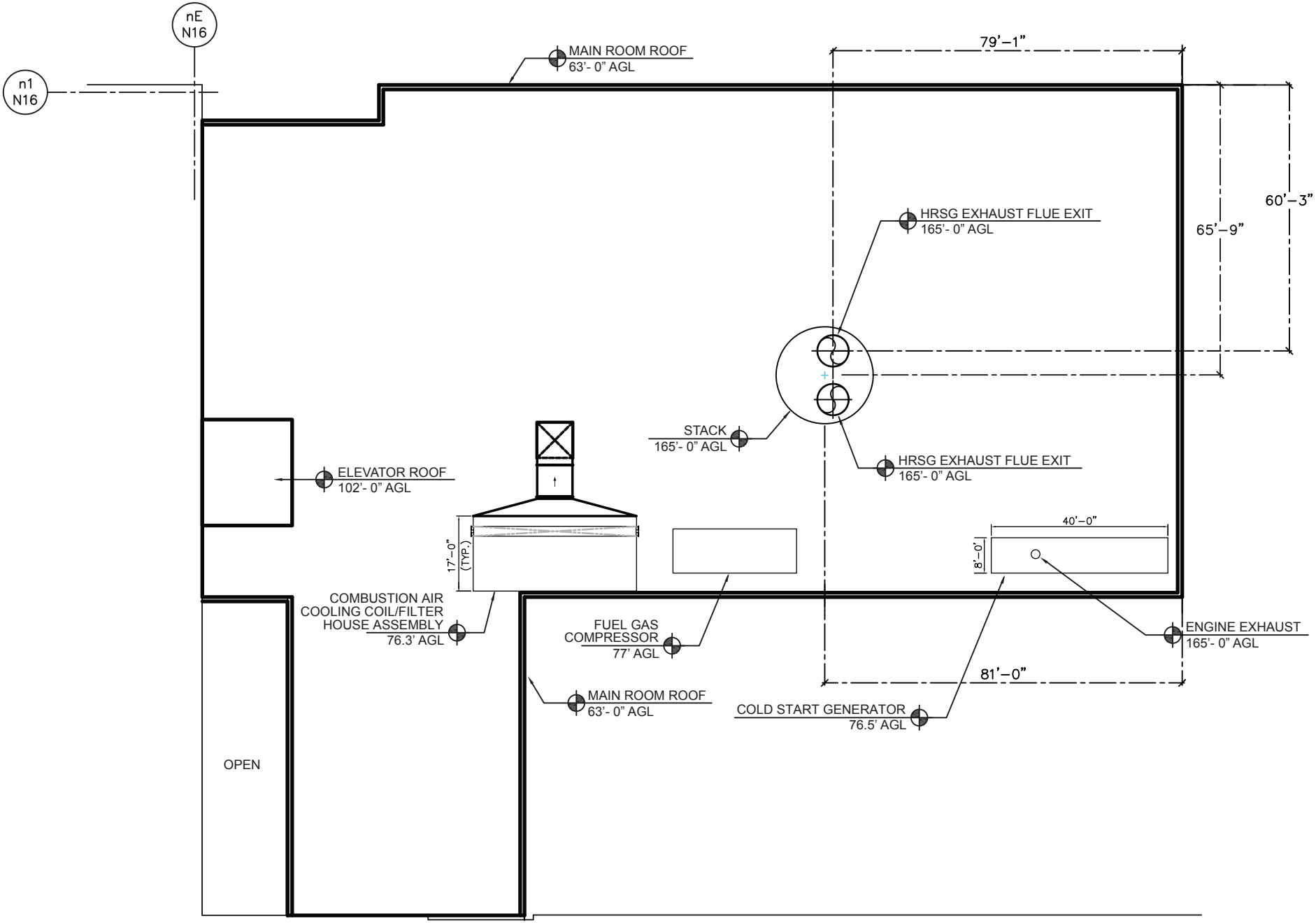


MIT Cogeneration Project Cambridge, Massachusetts

Epsilon Associates Inc.

Figure D-1

Aerial Locus Map



MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC

Figure D-2

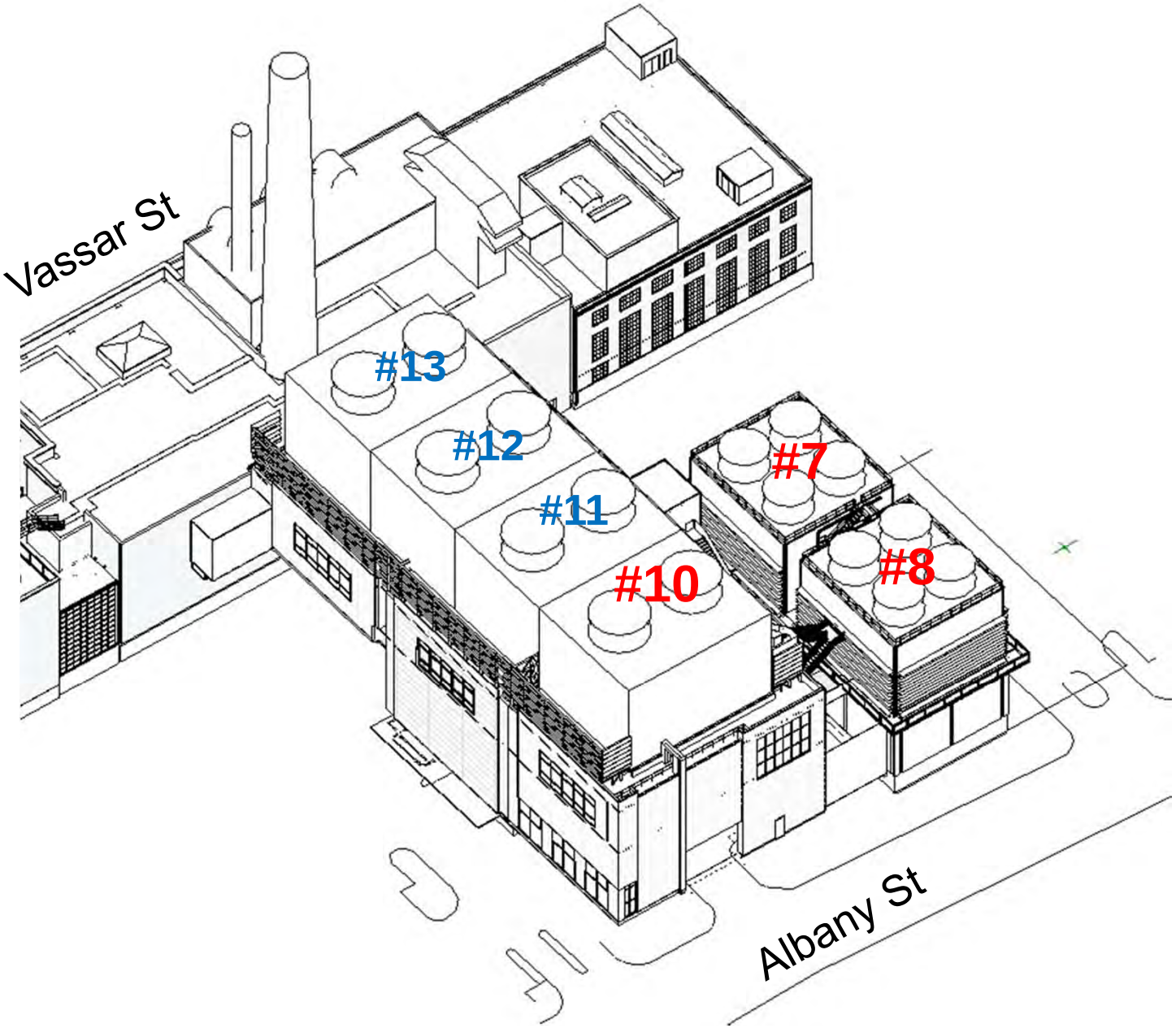
Project Layout/Site Plan

MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC.

Figure D-3

Existing Cooling Tower Locations



MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC.

Figure D-4

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

Table D-4. Operational Scenarios

Scenario	New Turbine Configuration	2 MW Cold Start Emergency 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 D-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 D-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 D-6 and D-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 D-8.

Table D-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 (°K)	Emission Rate (g/s)	Fuel	Load Condition
SO_2	1-Hour	20.0	355.4	0.14	NG	Case I.a: 60° F, Turbine #2 100% Load, Duct Burner On
	3-Hour	20.0	355.4	0.14	NG	Case I.a: 60° F, Turbine #2 100% Load, Duct Burner On
	24-Hour	20.0	355.4	0.14	NG	Case I.a: 60° F, Turbine #1 100% Load, Duct Burner On
	Annual	17.7	355.4	0.14[1]	NG	Case I.Annual: 60° F, Turbine #1, 75% Load, Duct Burner On
NO_x	1-Hour	22.5	380.4	1.28	ULSD	Case I.g: 0° F, Turbine #2, 100% Load, Duct Burner On
	Annual	17.7	355.4	0.49[1]	NG	Case I.Annual: 60° F, Turbine #1 75% Load, Duct Burner On
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
CO	1-Hour	22.5	380.4	0.70	ULSD	Case I.g: 0° F, Turbine #2, 100% Load, Duct Burner On
	8-Hour	22.5	380.4	0.70	ULSD	Case I.g: 0° F, Turbine #1, 100% Load, Duct Burner On

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

Table D-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 (°K)	Emission Rate[1] (g/s)	Fuel	Load Condition[2]
SO_2	1-Hour	20.0	355.4	0.27	NG	Case 2.a: 60°F, Turbines 1&2, 100% Load, Duct Burner On
	3-Hour	20.0	355.4	0.27	NG	Case 2.a: 60°F, Turbines 1&2, 100% Load, Duct Burner On
	24-Hour	17.7	355.4	0.23	NG	Case 2.e: 60°F, Turbines 1&2, 75% Load, Duct Burner On
	Annual	17.7	355.4	0.27[3]	NG	Case 2.Annual, Turbines 1&2, 75% Load, Duct Burner On
NO_x	1-Hour	22.5	380.4	2.56	ULSD	Case 2.g: 0°F, Turbines 1&2, 100% Load, Duct Burner On
	Annual	17.7	355.4	0.99[3]	NG	Case 2.Annual, Turbines 1&2, 75% Load, Duct Burner On
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
CO	1-Hour	18.9	380.4	1.15	ULSD	Case 2.h: 0°F, Turbines 1&2, 75% Load, Duct Burner On
	8-Hour	22.5	380.4	1.41	ULSD	Case 2.g: 0°F, Turbines 1&2, 100% 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 D-8. New 2MW Cold Start Emergency Engine and Cooling Tower Source Characteristics and Emission Rates

Source	Averaging Time	Exit Temp (K)	Exit Velocity (m/s)	PM_{10}/ $PM_{2.5}$ (g/s)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)
2MW Cold Start Emergency Engine	Short-Term	672.7	18.15	1.68E-2[1]	3.65E-3	0.151[2]	0.277
	Annual[3]			1.76E-3	1.26E-4	0.151	N/A
Cooling Towers #11, 12, 13 per cell (6)	N/A	298.7	8.0	4.40E-3	N/A	N/A	N/A

[1] Assumes cold start emergency engine will not operate more than 8 hours in a single day.
[2]This emission rate is scaled by the permitted hours of operation per EPA Guidance. (http://www.epa.gov/nsr/documents/20100629no2guidance.pdf)
[3] 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 D-9, D-10 and D-11.

Table D-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
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 D-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
NO_2	Short-term	Boiler #9 alone full load	Full load	Full load
	Annual	Boiler #9 alone full load	Full load	Full load
SO_2	Short-term	Boiler #7 and #9	Full load	Full load
	Annual	Boiler #9 alone full load	Minimum Load	Full load
CO	Short-term	Boiler #7 and #9	Full load	Full load

Table D-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)	SO_2 (g/s)	NO_x (g/s)	CO (g/s)
Boilers 7 & 9	Boilers 7 & 9 (full load)	Short-Term	473.7	17.68	0.83	0.83	4.16E-2	2.09	0.97
		Annual			-	0.29	4.16E-2	0.35	-
	Boiler 9 only (full load)	Short-Term	430.4	8.06	0.45	0.45	2.27E-2	1.50	0.53
		Annual			-	0.164	2.27E-2	0.20	-
Boilers 3,4,5	Full Load	Short-Term	430.4	5.91	2.62	2.62	7.18E-2	14.27	1.90
		Annual			-	1.45	7.18E-2	9.61	-
	Minimum Load	Short-Term	405.4	0.73	0.32	0.32	8.82E-3	1.76	0.23
		Annual			-	0.179	8.82E-3	1.18	-
Turbine #1	Full Load	Short-Term	405.4	35.79	1.756	1.756	5.92E-2	5.87	0.88
		Annual			-	0.63	5.92E-2	3.13	-
Generator	Full Load	Short-Term	790.3	61.94	9.58E-2	9.58E-2	4.03E-3	0.15[1]	0.28
		Annual			-	3.28E-3	1.39E-4	0.15	N/A
Cooling Tower 1 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3	N/A	N/A	N/A
Cooling Tower 2 per cell (2)	N/A	N/A	298.7	8.0	3.33E-3	3.33E-3	N/A	N/A	N/A
Cooling Tower 3 per cell (2)	N/A	N/A	298.7	8.0	5.86E-3	5.86E-3	N/A	N/A	N/A
Cooling Tower 4 per cell (2)	N/A	N/A	298.7	8.0	5.18E-3	5.18E-3	N/A	N/A	N/A
Cooling Tower 5	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3	N/A	N/A	N/A
Cooling Tower 6	N/A	N/A	298.7	8.0	2.15E-3	2.15E-3	N/A	N/A	N/A
Cooling Tower 7 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3	N/A	N/A	N/A
Cooling Tower 8 per cell (4)	N/A	N/A	298.7	8.0	4.91E-3	4.91E-3	N/A	N/A	N/A
Cooling Tower 9 per cell (4)	N/A	N/A	298.7	8.0	2.65E-3	2.65E-3	N/A	N/A	N/A
Cooling Tower 10 per cell (2)	N/A		298.7	8.0	4.40E-3	4.40E-3	N/A	N/A	N/A

[1] This emission rate is scaled by the permitted hours of operation per EPA Guidance. (http://www.epa.gov/nsr/documents/20100629no2guidance.pdf)

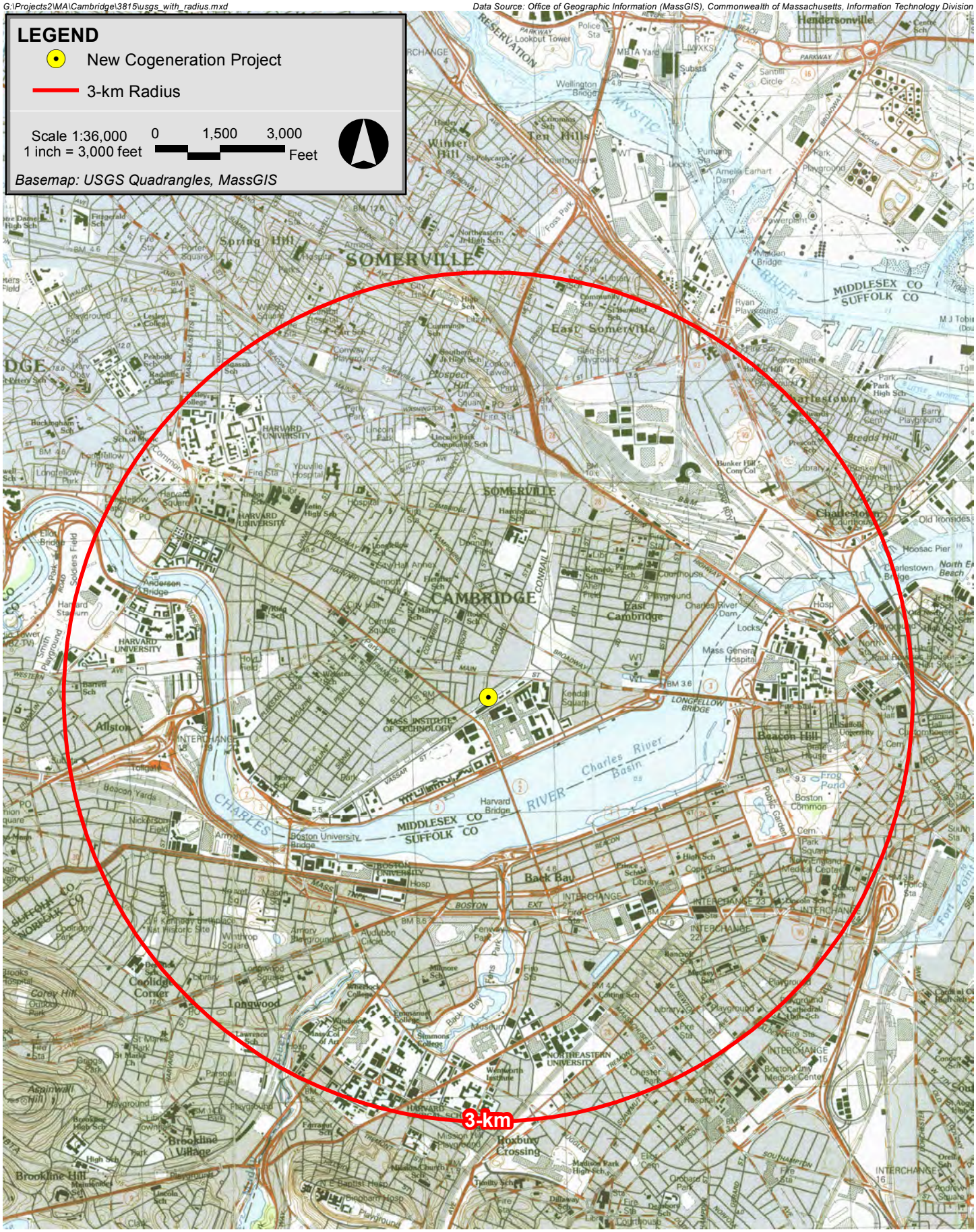
D-3.4 Urban/Rural Analysis

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 D-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 D-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 D-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	

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



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon Associates Inc.

Figure D-5

USGS Topographic Map with 3-km Radius

D-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 and MAAQS. 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. Data is also available via the EPA website (http://www.epa.gov/airquality/airdata) and was used for the 3-hour and 24-hour SO_2 averages since these are no longer included in the published monitor reports. 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. All pollutants are monitored at Kenmore Square, i.e., SO_2, CO, NO_2, PM_{10}, and $PM_{2.5}$. A summary of the background air quality concentrations based on the 2012-2014 data are presented in Table D-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 D-13. Observed Ambient Air Quality Concentrations and Selected Background Levels

Pollutant	Averaging Period	2012	2013	2014	Background Level	NAAQS
SO_2 ($\mu g/m^3$)	1-hour	13.2	31.4	25.4	23.3	196
	3-Hour[a]	27.8*	36.4*	24.6*	36.4	1,300
	24-Hour[b]	14.1	15.7*	13.1*	15.7	365
	Annual	4.9	2.6	2.5	4.9	80
CO ($\mu g/m^3$)	1-Hour	1489.8	1489.8	1962.4	1962.4	40,000
	8-Hour	1031.4	1031.4	1260.2	1260.2	10,000
NO_2 ($\mu g/m^3$)	Annual	33.5	33.5	32.3	33.1	100
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[c]	9.0	8.0	6.0	7.7	12

Notes: (conversion factors of 1 ppm = 2620 $\mu g/m^3$ SO_2; = 1146 $\mu g/m^3$ CO; and 1882 $\mu g/m^3$ NO_2 used).

* data obtained from EPA at http://www.epa.gov/airquality/airdata;

[a] Background level for 3-hr SO_2 is the highest-second-high SO_2 value (obtained from EPA website).

[b] Background level for 24-hr SO_2 and PM_{10} is based on the highest-second-high value.

[c] 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 $PM_{2.5}$ and 1-hour NO_2 are not represented in Table D-13 because daily background values of $PM_{2.5}$ were used in a post-processing step for the concurrent period of modeling 2010-2014. For comparison with the 1-hr NO_2 standard, the 3-year (2012-2014) average of the 98th percentile background concentration by season and hour-of-day was used.

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 174 North Street (a daily $PM_{2.5}$ monitoring site with two FRM monitors) 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 primarily 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.

For 1-hr NO_2, the seasonal diurnal variation of measured data was taken into account (SEASHR option in AERMOD) using the 3-year (2012-2014) average of the 98th percentile background concentration by season and hour-of-day (per EPA 1-hr NO_2 memo, June 28, 2010).

D-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 D-14 presents the difference between the NAAQS and the monitored background concentration, compared to the SILs. As shown in Table D-13, 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 as de minimis levels for all pollutants is appropriate.

Table D-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 ($\mu g/m^3$)
SO_2	1-Hour	23.3	196	172.7	7.8
	3-Hour	36.4	1,300	1263.6	25
	24-Hour	15.7	365	349.3	5
	Annual	4.9	80	75.1	1
CO	1-Hour	1962.4	40,000	38,037.6	2,000
	8-Hour	1260.2	10,000	8,739.8	500
NO_2	1-Hour	90.9	188	97.1	7.5
	Annual	33.1	100	66.9	1
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

D-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,

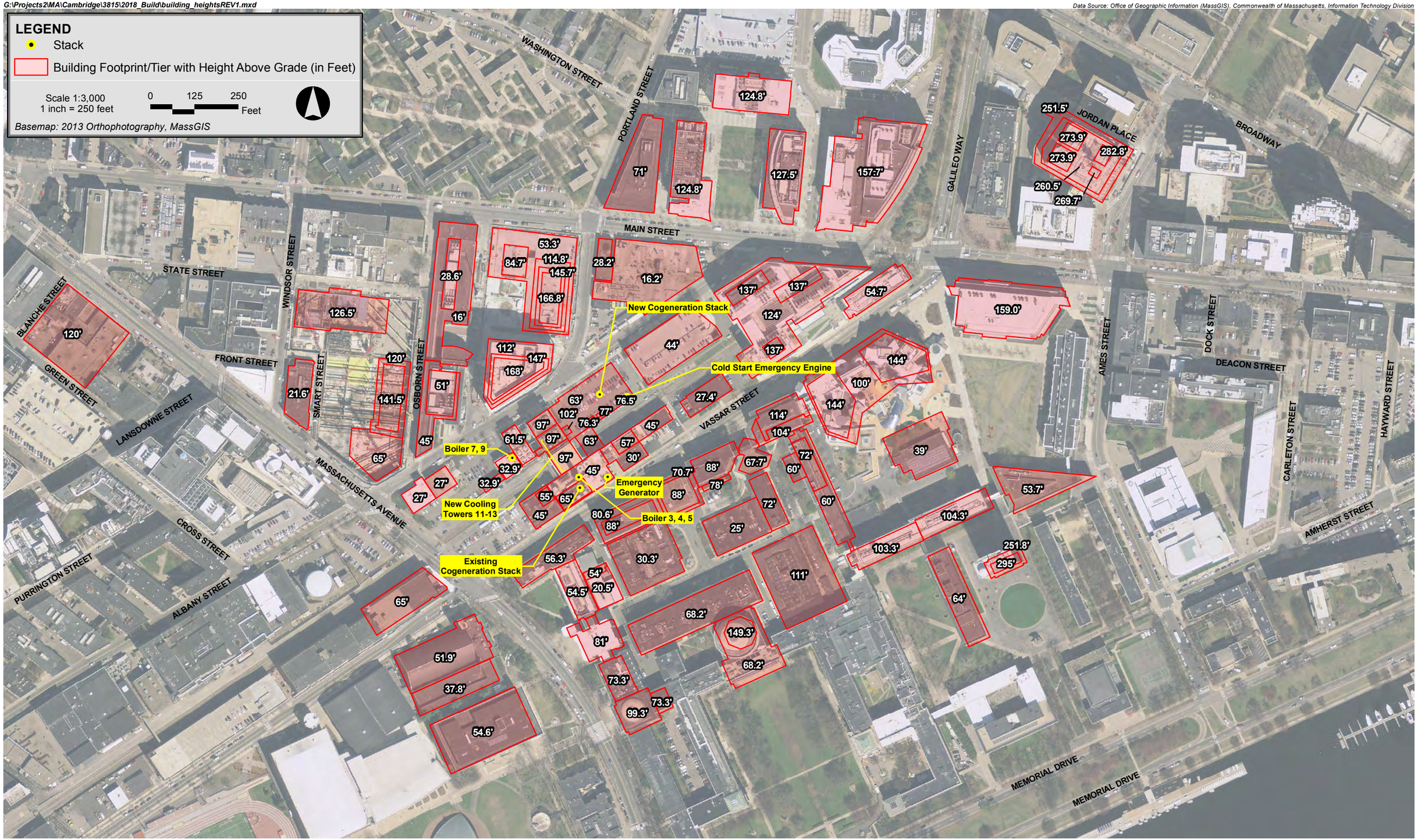
L = Lesser of height or maximum projected width of adjacent or nearby building, i.e., the critical dimension, and

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 D-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 D-6

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

D-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 state and 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 criteria pollutants for comparison with the SILs
- Modeling of criteria pollutants for comparison with the NAAQS, including interactive source modeling for some pollutants.
- Modeling of non-criteria pollutants for comparison with the Massachusetts TELs and AALs
- Modeling for comparison with the PSD Increments for PSD pollutants
- VISCREEN modeling

Impacts of criteria 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 D-2).

Per MassDEP Modeling Guidance for Significant Stationary Sources of Air Pollution (MassDEP, 2011), if impacts are below SILs, a NAAQS 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.

D- 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 D-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 criteria pollutant concentrations which are compared to the SILs presented earlier in Table D-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, coupled with the proposed operational changes described earlier and the proposed modifications 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 recently 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 D-3.5-1).

In addition to modeling for the criteria pollutants, an air toxic assessment was conducted with the AERMOD model. The predicted impacts of the emitted non-criteria pollutants are compared to the Massachusetts' annual average Allowable Ambient Limit values (AALs) and the 24-hour average Threshold Effects Exposure Limit values (TELs).

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.

D- 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 D-5 through D-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 except for the assumption of 100% conversion of nitrogen oxides (NO_x) to nitrogen dioxide (NO_2).

The chemical conversion of NO_x into NO_2 is an important factor when assessing short-term NO_2 concentrations. It is determined that for short-term NO_2 impacts, the Plume Volume Molar Ratio Method (PVMRM) is the most appropriate method to be used. The PVMRM determines the conversion rate for NO_x to NO_2 based on a calculation of the NO_x moles emitted into the plume, and the amount of ozone moles contained within the volume of the plume between the source and receptor.

The PVMRM method is available as a non-regulatory-default options within the EPA-preferred AERMOD dispersion model. As a result of the non-regulatory-default status, pursuant to Sections 3.1.2.c, 3.2.2.a, and A.1.a(2) of 40 CFR Part 51, Appendix W, application of AERMOD with any non-default option is no longer considered a "preferred

model" and, therefore, requires justification and approval by the Regional Office on a case-by-case basis. Use as an alternative modeling technique under Appendix W should be justified in accordance with the five requirements of Section 3.2.2, paragraph (e).

The following addresses each of the five requirements noted in Section 3.2.2(e) in order to justify the use of PVMRM for the purpose of determining compliance with the Federal 1-hour NO_2 standard.

3.2.2 (e)(i). The model has received a scientific peer review;

- The chemistry for the PVMRM model has received scientific peer review as noted in "Sensitivity Analysis of PVMRM and OLM in AERMOD" (MACTEC, 2004) and "Evaluation of Bias in AERMOD-PVMRM"(MACTEC, 2005). Both documents indicate that the model appears to perform as expected. The EPA suggests that the PVMRM produces a more realistic conversion of NO_X to NO_2 than other available methods.

3.2.2 (e)(ii). The model can be demonstrated to be applicable to the problem on a theoretical basis;

- The PVMRM model has been reviewed and the chemistry has been widely accepted by EPA as being appropriate for addressing the formation of NO_2 and the calculation of NO_2 concentration at receptors downwind. Additionally, the ""Sensitivity Analysis of PVMRM and OLM in AERMOD" report would indicate OLM/PVMRM provides a better estimation of the NO_2 impacts compared to other screening options.

3.2.2 (e)(iii). The data bases which are necessary to perform the analysis are available and adequate;

- Five years (2010-2014) of both hourly processed meteorological data (Boston, MA/Gray, ME) and concurrent hourly ozone monitoring data are available for this modeling application. Hourly ozone concentrations from the Harrison Ave. monitoring station (2.3 miles south-southeast of the MIT CUP) will be input to AERMOD for each year modeled (2010-2014). The Lynn and Milton monitoring stations will be used to replace hours with missing ozone data (10 miles to the northeast and 10.4 miles to the south-southwest, respectively). These data sets are adequate for use with AERMOD-PVMRM.

3.2.2 (e)(iv). Appropriate performance evaluations of the model have shown that the model is not biased toward underestimates;

- As noted the "Evaluation of Bias in AERMOD-PVMRM" report, PVMRM has been judged to provide an unbiased estimate.

3.2.2 (e)(v). A protocol on methods and procedures to be followed has been established.

- The methods and procedures for conducting an assessment for determining compliance with the federal 1-hour NAAQS are contained within. Specific PVMRM inputs are discussed here. The default value of 0.9 is used for the ambient equilibrium ratio in PVMRM. The in-stack ratio of NO_2/NOx is set to the default value of 0.5 for all sources except for the following: (a) 0.2 for the new ULSD-fired 2MW cold start IC emergency engine and the existing diesel fired emergency generator based on past use for emergency generator engines and CAPCOA guidance[2]; (b) For oil fired operation of the existing No. 6 oil fired Boilers 3,4 and 5 a 0.10 for the in-stack ratio is used based on past use in other recent modeling such as Mystic 7 for the PSD modifications for Mystic 8 and 9 startup emissions. The value is also supported by other sources.[3] The Ambient Ratio Method (ARM) scaling factor of 0.75 is applied to the annual NO_2 predicted concentration. This is a U.S. EPA default approach based on the assumption that 75% of the NOx will convert to NO_2 on an annual basis.

D-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.

---

2 See Appendix C for default of 0.2 for diesel fired IC engines: http://www.valleyair.org/busind/pto/Tox_Resources/CAPCOANO2GuidanceDocument10-27-11.pdf

3 Page 8,13 of http://www.epaz.org/userfiles/8-NO2-Measurements-%20M%20Carpenter.pdf;

- 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.

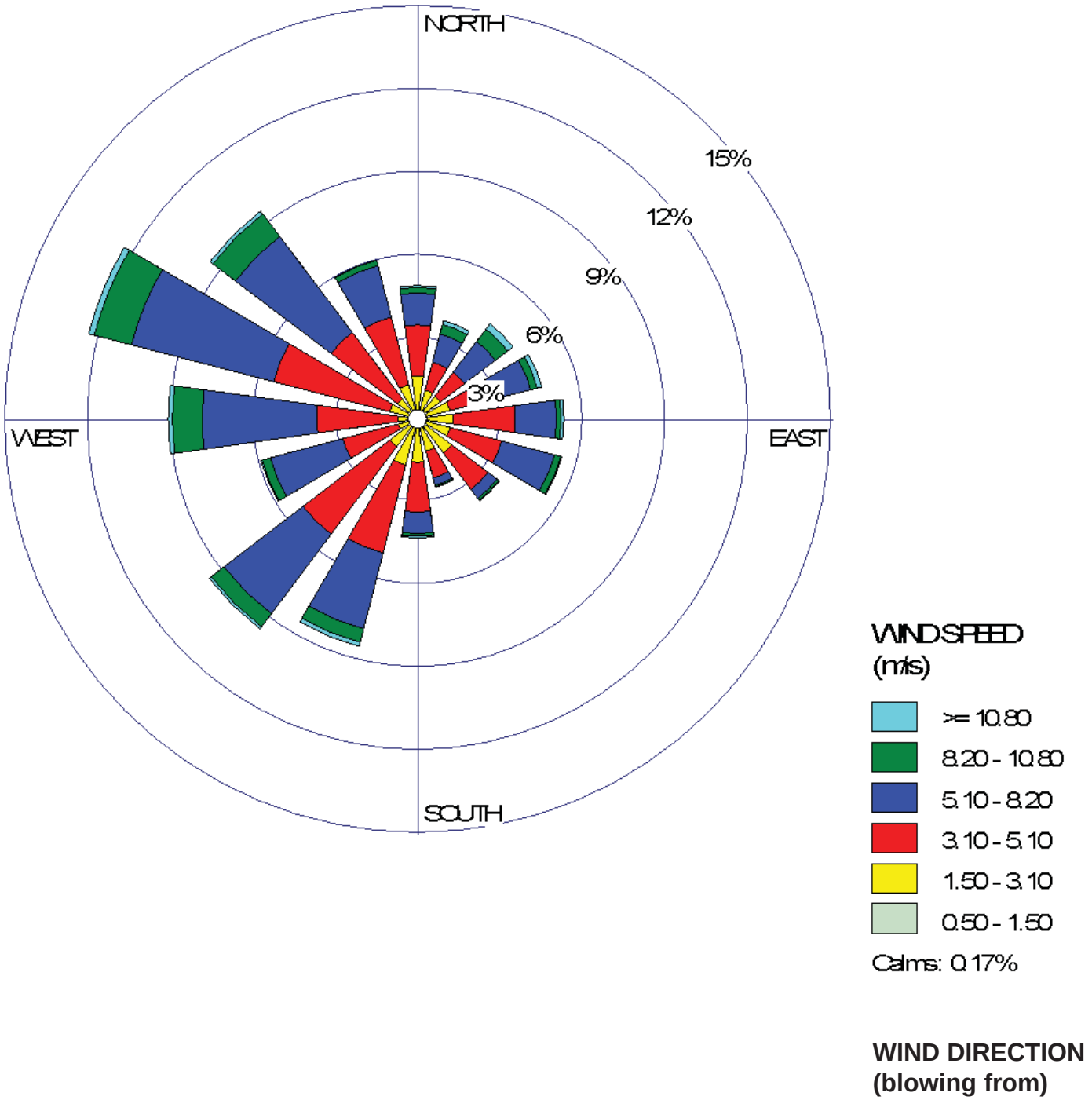
- In order to make a determination as to whether Boston experiences continuous snow cover during the winter months, the 30-year climatological (1981-2010) monthly normal snow depth data was used. During this period Boston experienced at least an inch of snow on the ground less than 50% of the time. Therefore, 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 D-7. The winds are predominantly from the western sector (SSW through NW).

D-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.

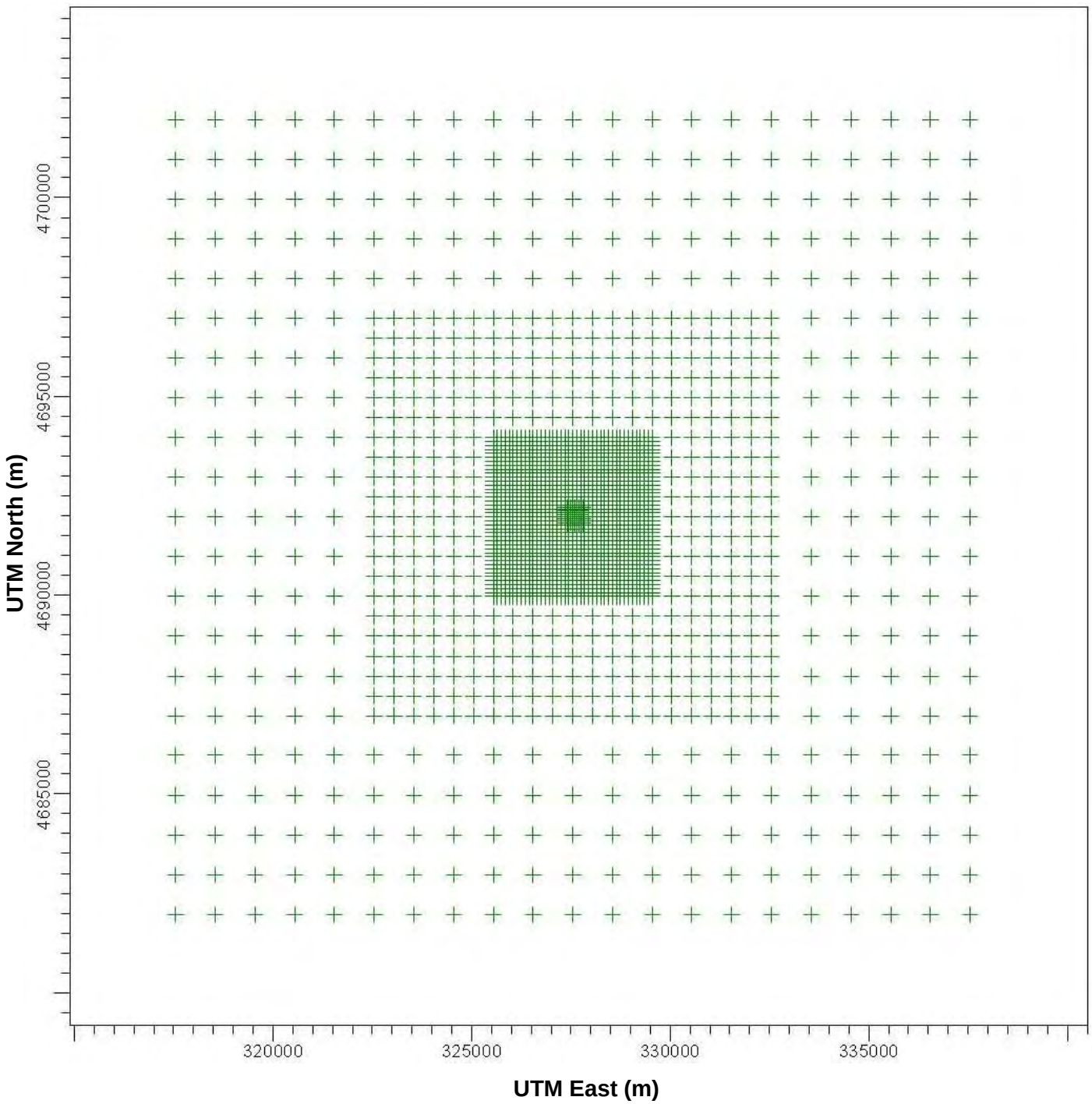


MIT Cogeneration Project **Cambridge, Massachusetts**

Figure D-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 D-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

MIT Cogeneration Project **Cambridge, Massachusetts**

Epsilon ASSOCIATES INC.

Figure D-8

Nested Receptor Grid used in AERMOD Modeling

D-5. AIR QUALITY IMPACT RESULTS

D-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 D-3.3, the source data section, in Tables D-6 and D-7.

D-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, 2 MW cold start emergency engine and the cooling towers (PM only). Each of the Operating Scenarios was modeled for comparison with the SILs. Table D-15 presents the criteria pollutant concentrations compared to the SILs for each operating scenario. Maximum concentrations of SO_2 and CO are below the SILs for all averaging periods for all operational scenarios. Maximum concentrations of NO_2, $PM_{2.5}$, and PM_{10} are above SILs for various averaging times (shown in bold). 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 D-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)							
SO_2	1-hr (1)	H	2.11	7.8	27%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr	H	1.81	25	7%	10/1/13 hr 15	327450.08, 4692162.84, 2.73
	24 -hr	H	1.41	5	28%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
	Annual	H	0.18	1	18%	2010	327550.08, 4692062.84, 2.73
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 (2)	H	**11.3**	1.2	945%	2010-2014	327550.08, 4692062.84, 2.73
	Ann. (2)	H	**1.02**	0.3	341%	2010-2014	327550.08, 4692062.84, 2.73

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

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)							
NO_2	1-hr [(1)(3)]	H	**16.3**	7.5	217%	2010-2014	327500.08, 4692112.84, 2.73
	Annual	H	**1.81**[3]	1	181%	2010	327550.08, 4692062.84, 2.73
CO	1-hr	H	17.8	2000	0.9%	6/24/13 hr 16	327600.08, 4692112.84, 2.73
	8-hr	H	15.0	500	3.0%	1/9/14 hr 8	327600.08, 4692112.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)							
SO_2	1-hr [(1)]	H	2.71	7.8	35%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr	H	2.26	25	9%	5/21/14 hr 12	327500.08, 4692112.84, 2.73
	24-hr	H	1.80	5	36%	1/29/10 hr 24	327650.08, 4692062.84, 2.74
	Annual	H	0.18	1	18%	2011	327850.08, 4692362.84, 2.75
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 [(2)]	H	**12.41**	1.2	1034%	2010-2014	327550.08, 4692062.84, 2.73
	Ann. [(2)]	H	**1.15**	0.3	383%	2010-2014	327850.08, 4692362.84, 2.75
NO_2	1-hr [(1)(3)]	H	**19.0**	7.5	253%	2010-2014	327500.08, 4692112.84, 2.73
	Annual	H	**1.67**[3]	1	167%	2010	327550.08, 4692062.84, 2.73
CO	1-hr	H	18.1	2000	1%	8/9/12 hr 11	327400.08, 4692162.84, 2.73
	8-hr	H	15.0	500	3%	1/9/14 hr 8	327600.08, 4692112.84, 2.73

[1] High 1st High maximum daily 1-hr concentrations averaged over 5 years.
[2] Concentrations averaged over 5 years.
[3]Annual NO_2 uses ARM for NOx to NO_2 conversion of 0.75 per EPA Guidance. http://www.epa.gov/scram001/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

D-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 D-15) the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. These results are presented in Section D-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 D-5.3.2.

Post-processing of 1-hour NO_2

As AERMOD is run for the 1-hour NO_2 impacts (using the PVMRM option), the seasonal/diurnal values of NO_2 monitored background were input directly to the model. The appropriate background value was added to the modeled impact depending on the season and hour of day. Then the daily maximum of the total (modeled + background) hourly impacts was determined for each day. Following EPA's guidance (EPA, 2011) the design value is the 98th percentile highest of the annual distribution of the daily maximum 1-hour total impact at each receptor for the multiyear average (5 years). This analysis was performed for each receptor, and the results were compared to the 1-hour NO_2 standard.

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.

D-5.3.1 MIT Sources

AERMOD modeling was performed for the pollutants and averaging periods which had Project impacts below the SILs (Table D-15). The new MIT sources were modeled with the existing MIT sources; then the appropriate modeled concentrations were combined with appropriate ambient background concentrations prior to comparison with the NAAQS. For Operational Scenario 1 when only one new turbine is in operation, the existing turbine is still operating. The existing turbine will be shut down once two new turbines are in operation (Scenario 2). For Scenario 2, the flues for the two new turbines are merged and modeled with an effective diameter of 9.9 ft. Table D-16 presents the criteria pollutant concentrations compared to the NAAQS for each operating scenario. The total concentration (modeled plus background) are below the NAAQS for all pollutants.

Table D-16. AERMOD Model Results for the Full MIT Facility for Operational Scenarios 1 & 2 Compared to the NAAQS[1]

Poll.	Avg. Period	Form	AERMOD Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	NAAQS (μg/m3)	% of NAAQS	Period	Receptor Location (m) (UTME, UTMN, Elev.)
Operational Scenario 1 (1 new turbine/HRSG)									
SO_2	1-hr[(2)]	H4H	3.2	23.3	26.5	196	14%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr.	H2H	2.8	36.4	39.2	1300	3%	8/12/14 hr 18	327500.08, 4692162.84, 2.73
	24-hr.	H2H	1.8	15.7	17.5	365	5%	12/21/10 hr 24	327550.08, 4692062.84, 2.73
	Annual	H	0.29	4.9	5.2	80	6%	2010	327550.08, 4692062.84, 2.73
CO	1-hr.	H2H	62.1	1962.4	2024.5	40000	5%	5/26/11 hr 12	327500.08, 4692212.84, 2.73
	8-hr	H2H	42.9	1260.2	1303.1	10000	13%	9/18/12 hr 16	327500.08, 4692162.84, 2.73
Operational Scenario 2 (2 new turbines/HRSGs)									
SO_2	1-hr[(2)]	H4H	3.3	23.3	26.6	196	14%	2010-2014	327500.08, 4692112.84, 2.73
	3-hr	H2H	2.7	36.4	39.1	1300	3%	8/12/14 hr 18	327500.08, 4692162.84, 2.73
	24-hr	H2H	1.9	15.7	17.6	365	5%	1/3/10 hr 24	327550.08, 4692062.84, 2.73
	Annual	H	0.23	4.9	5.1	80	6%	2010	327550.08, 4692062.84, 2.73
CO	1-hr.	H2H	52.4	1962.4	2014.8	40000	5%	5/26/11 hr 12	327500.08, 4692212.84, 2.73
	8-hr	H2H	40.1	1260.2	1300.3	10000	13%	1/24/14 hr 16	327550.08, 4692062.84, 2.73

[1] PM_{10} 24-hr, $PM_{2.5}$ 24-hr, $PM_{2.5}$ Annual, NO_2 1-hr, NO_2 Annual impacts from MIT are reported in Table D-17

[2] High 4th High (99th%) maximum daily 1-hr concentration averaged over 5 years.

D-5.3.2 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 $PM_{2.5}$, 24-hr PM_{10} and 1-hr and annual NO_2 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 $PM_{2.5}$, PM_{10} or NO_2 emission rates (>10 tpy $PM_{2.5}$, >15 tpy PM_{10} or >40 tpy NO_2 based on reported actual emissions). Four nearby facilities have been identified satisfying the criteria for PM_{10} and $PM_{2.5}$. Two additional sources were identified satisfying the criteria for NO_2. 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)
5. (NO_2 Only) Logan Airport (~5.9 km to the east-northeast of the MIT CUP)
6. NO_2 Only) Kneeland Street (~3.2 km to the east-southeast of the 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. Determine the NOx emission rate for Kendall Station sources.
  3. Emission rates were adjusted because Kendall Station no longer burns No. 6 fuel oil.
- A review of the most recent operating permit for Mystic Station was used to determine the NOx emission rate for Mystic Station sources.

- 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 D-17.

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 D-17. 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) (UTME, UTMN, Elev.)
				MIT	Kendall Station	Harvard Blackstone	MATEP	Mystic Station	Kneeland Street	Logan Airport					
Operational Scenario 1 (1 new turbine/HRSG)															
PM_{10}	24-hr	H6H	85.7	0.045	32.4	0.23	0.0020	0.018	N/A	N/A	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	N/A	N/A	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	N/A	N/A	7.7	12	90.8%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr[(1)]	H8H	143.7	66.8	0.010	0.0083	0.14	0.025	0.015	0.047	76.7	188	76.4%	2010-2014	327500.0, 4692212.84, 2.73
	Annual[(2)]	H	46.7	9.38	1.03	0.99	0.77	0.61	0.47	0.25	33.1	100	46.7%	2010	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	N/A	N/A	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	N/A	N/A	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	N/A	N/A	7.7	12	87.8%	2010-2014	327550.08, 4692112.84, 2.73
NO_2	1-hr[(1)]	H8H	139.8	55.14	0.15	0.12	0.070	0.038	0.052	0.034	84.2	188	74.4%	2010-2014	327550.08, 4692062.84, 2.73
	Annual[(2)]	H	46.2	8.92	1.04	1.06	0.78	0.61	0.48	0.25	33.1	100	46.2%	2010	327550.08, 4692062.84, 2.73

[1] High 8th High (98th%) maximum daily 1-hr concentration averaged over 5 years with seasonal/diurnal background; PVMRM used for conversion of NOx to NO_2.

[2] Annual NO_2 uses ARM for NOx to NO_2 conversion of 0.75 per EPA Guidance. http://www.epa.gov/scram001/guidance/clarification/Additional_Clarifications_AppendixW_Hourly-NO2-NAAQS_FINAL_03-01-2011.pdf

D-5.4 Non-Criteria Pollutant Modeling

An air quality impact assessment of the non-criteria pollutants emitted from the proposed combustion sources (two new turbines and 2 MW cold start emergency engine) was conducted. Applicable EPA AP-42 and California Air Toxic Emission Factor (CATEF) emission factors were used to derive the emission rates. The highest 24-hr and annual normalized AERMOD predicted concentrations were used, and then scaled by the pollutant emission rate to obtain the predicted concentration of each pollutant. For the TEL modeling, Case 2.D (NG) and Case 2.I (ULSD) were used and the worst-case impact was reported in Table D-18. Calculations are shown in Attachment D. The results in Table D-18 presents the worst-case predicted non-criteria pollutant air quality impacts for those pollutants for which MassDEP has an annual Allowable Ambient Limit (AAL) or a 24-hour Threshold Effects Exposure Limit (TEL). The results show that air quality impacts from the non-criteria emissions are well below the threshold levels of the corresponding MassDEP AALs and TELs.

Table D-18 Non-Criteria Pollutant Modeled Concentrations from CoGen Project Combustion Sources for Comparison to Massachusetts' AALs and TELs

Pollutant	Annual Concentrations ($\mu g/m^3$)			24-Hour Concentrations ($\mu g/m^3$)		
	Total Impact	AAL	% of AAL	Total Impact	TEL	% of TEL
1,3-Butadiene	2.59E-05	0.003	0.9%	4.61E-03	1.2	0.4%
Acetaldehyde	1.34E-03	0.4	0.3%	1.19E-02	30	0.0%
Acrolein	2.14E-04	0.07	0.3%	2.11E-03	0.07	3.0%
Benzene	1.07E-03	0.1	1.1%	7.71E-02	0.6	12.9%
Dichlorbenzene	2.66E-05	81.74	0.0%	4.17E-04	81.74	0.0%
Ethylbenzene	1.06E-03	300	0.0%	8.42E-03	300	0.0%
Formaldehyde	1.33E-02	0.08	16.7%	2.17E-01	2	10.9%
Hexane	3.98E-02	47.62	0.1%	6.25E-01	95.24	0.7%
Naphthalene	1.83E-04	14.25	0.0%	1.73E-02	14.25	0.1%
Propylene Oxide	9.65E-04	0.3	0.3%	7.63E-03	6	0.1%
Toluene	4.45E-03	20	0.0%	5.07E-02	80	0.1%
Xylenes	2.16E-03	11.8	0.0%	2.73E-02	11.8	0.2%
Arsenic	5.97E-06	0.0003	2%	6.13E-04	0.003	20.4%
Beryllium	5.12E-07	4.00E-04	0.1%	9.27E-05	1.00E-03	9.3%
Cadmium	2.46E-05	2.00E-04	12.3%	1.02E-03	2.00E-03	51.1%
Chromium	3.29E-05	0.68	0.0%	3.54E-03	1.36	0.3%
Lead	8.19E-06	0.07	0.0%	4.03E-03	0.14	2.9%
Mercury	6.36E-04	0.07	0.9%	4.15E-04	0.14	0.3%
Nickel	4.74E-05	0.18	0.0%	1.88E-03	0.27	0.7%
Selenium	4.20E-06	0.54	0.0%	7.21E-03	0.54	1.3%

D-5.5 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 D-19. Calculations are provided in Attachment C.

Table D-19. 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 D-20.

Table D-20. 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 D-21. The analysis shows that applicable PSD increments are not exceeded at any receptor for any MIT CoGen operating scenario.

Table D-21. AERMOD Model Results for Operational Scenarios 2 compared to PSD Increments

Poll.	Avg. Period	Form	Resultant Modeled Conc. ($\mu g/m^3$)	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

D-5.6 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 D-22 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 D-22 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

D-5.7 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.

D-5.8 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.

D-5.9 Environmental Justice

Section 4.2 of the PSD 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 D-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 pollutants/averaging times above the SIL (NO_2, PM_{10}, and $PM_{2.5}$) were 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 D-23. 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.

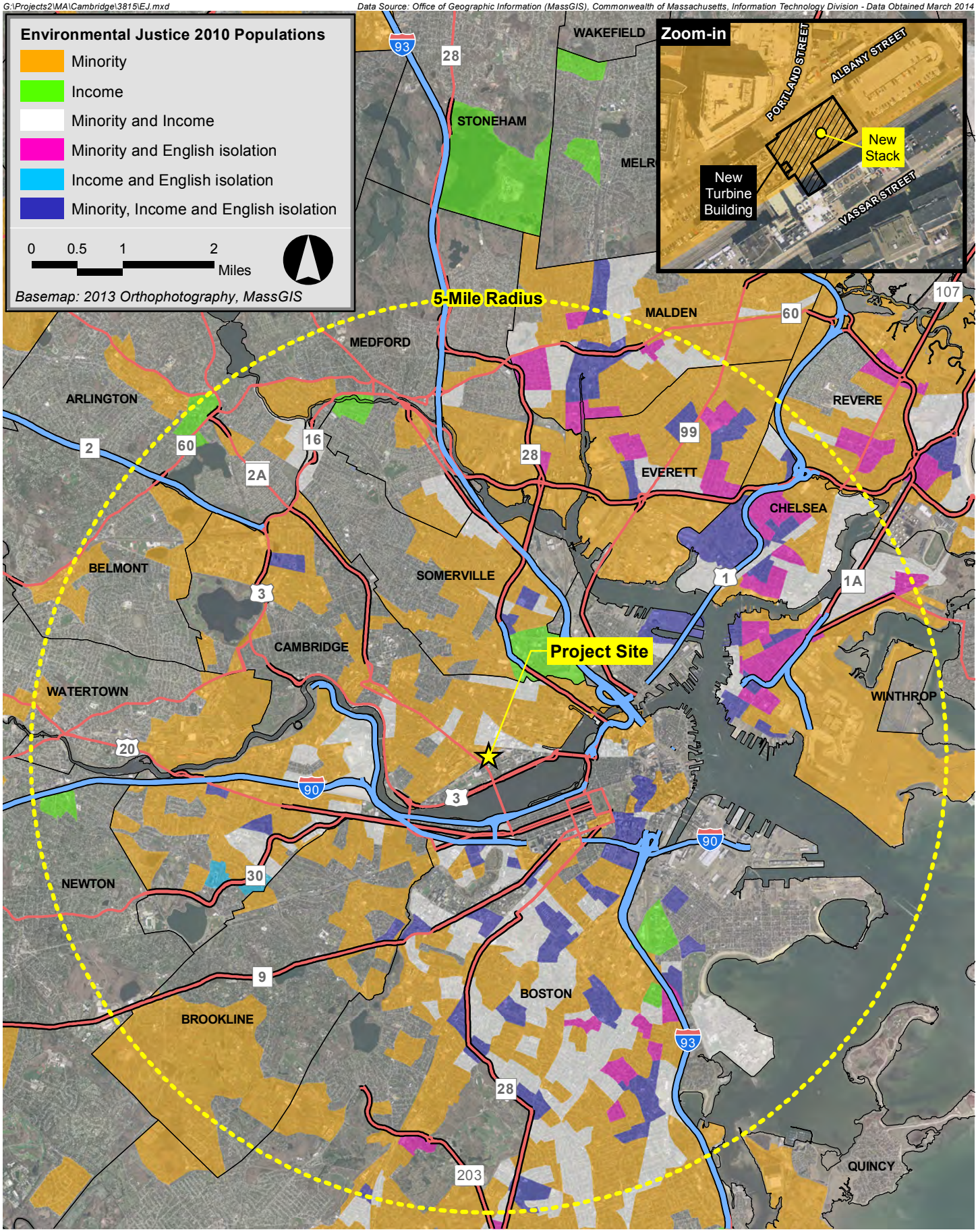
Table D-23 Population-weighted Predicted Impacts

		Population-weighted Concentration ($\mu g/m^3$)	
Pollutant	Averaging Period	Non-EJ Areas	EJ Areas
NO_2	1-hour	16.2	16.5
	Annual	0.2	0.2
$PM_{2.5}$	24-hour	1.7	1.8
	Annual	0.04	0.05
PM_{10}	24-hour	1.3	1.4

As previously demonstrated in Table D-17, 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 D-17 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.

G:\Projects2\MA\Cambridge\3815\EJ.mxd

Data Source: Office of Geographic Information (MassGIS), Commonwealth of Massachusetts, Information Technology Division - Data Obtained March 2014



MIT Cogeneration Project Cambridge, Massachusetts

Epsilon Associates Inc.

Figure D-9

Environmental Justice 2010 Populations

D-6. REFERENCES

40 CFR Part 51, Appendix W. "Guideline on Air Quality Models"

Alaska DEC., 2012. NO_2-NOx Instack Ratios per Source Tests Approved by the Alaska Department of Environmental Conservation. (Spreadsheet, last updated May 14, 2012)

Auer, A.H., 1977. Correlation of Land Use and Cover with Meteorological Anomalies. J. Applied. Meteor., 17:636-643.

EPA, 1980. "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals". EPA 450/2-81-078, U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 1985. "Guideline for Determination of Good Engineering Practice Stack Height", EPA-450/4-80-023R, June, 1985.

EPA, 1988. "Workbook for Plume Visual Impact Screening and Analysis". EPA 450/4-88-015, U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 1990. "New Source Review Workshop Manual – Prevention of Significant Deterioration and Non Attainment Area Permitting." Office of Air Quality Planning and Standards, Research Triangle Park, NC.

EPA, 2004. "User's Guide for the AMS/EPA Regulatory Model-AERMOD". EPA-454/B-03-001, U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2009. "AERMOD Implementation Guide". U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2010. Applicability of Appendix W Modeling Guidance for the 1-hour SO2 National Ambient Air Quality Standard. U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2011. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard. U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2013. "AERSURFACE User's Guide". EPA-454/B-08-001 (revised 1/16/2013). U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2013. Use of ASOS Meteorological Data in AERMOD Dispersion Modeling. U.S. Environmental Protection Agency, Research Triangle Park, NC.

EPA, 2014. Guidance for $PM_{2.5}$ Permit Modeling. EPA-454/B-14-001 (May 2014). U.S. Environmental Protection Agency, Research Triangle Park, NC.

MACTEC, 2004. Sensitivity Analysis of PVMRM and OLM in AERMOD, Alaska DEC Contract No. 18-8018-04, MACTEC Federal Programs Inc., Research Triangle Park, NC.

MACTEC, 2005. Evaluation of Bias in AERMOD-PVMRM. Alaska DEC Contract No. 18-9010-12, MACTEC Federal Programs Inc., Research Triangle Park, NC.

MassDEP, 2011. Modeling Guidance for Significant Stationary Sources of Air Pollution. MassDEP Bureau of Waste Prevention, Boston, MA.

ATTACHMENT A

Source Parameters for New Turbine Load Cases

Table A-1. MIT turbine & duct burner Short Term model cases,

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																				
CO	1.21	1.21	1.75	1.18	0.94	1.76	4.10	3.20	2.37	2.38	2.42	2.42	3.50	2.36	1.87	3.52	8.20	6.41	4.73	4.77
NOx	1.99	1.99	1.84	1.55	2.46	2.32	8.66	6.77	5.00	5.04	3.98	3.98	3.68	3.10	4.92	4.63	17.33	13.54	10.00	10.07
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
SO2	7.31E-1	7.31E-1	4.23E-1	2.85E-1	5.65E-1	4.26E-1	3.85E-1	3.01E-1	2.22E-1	2.24E-1	1.46E+0	1.46E+0	8.45E-1	5.7E-1	1.13E+0	8.51E-1	7.70E-1	6.01E-1	4.44E-1	4.47E-1
Duct Burner - Lb/Hr																				
CO	1.37	1.48	1.03	0.35	1.34	1.11	1.48	1.34	1.03	1.11	2.75	2.95	2.06	0.71	2.68	2.22	2.95	2.68	2.06	2.22
NOx	1.37	1.48	1.03	0.35	1.34	1.11	1.48	1.34	1.03	1.11	2.75	2.95	2.06	0.71	2.68	2.22	2.95	2.68	2.06	2.22
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
SO2	3.57E-1	3.84E-1	2.68E-1	9.19E-2	3.48E-1	2.88E-1	2.09E-1	1.89E-1	1.46E-1	1.57E-1	7.14E-1	7.67E-1	5.36E-1	1.84E-1	6.96E-1	5.76E-1	7.67E-1	6.96E-1	5.36E-1	5.76E-1
Total Emissions (Lb/Hour)																				
CO	2.58	2.69	2.78	1.53	2.28	2.87	5.58	4.54	3.40	3.49	5.17	5.37	5.56	3.07	4.55	5.74	11.16	9.09	6.79	6.98
NOx	3.36	3.47	2.87	1.91	3.80	3.42	10.14	8.11	6.03	6.14	6.73	6.93	5.74	3.81	7.60	6.85	20.28	16.22	12.06	12.29
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
SO2	1.09	1.11	0.69	0.38	0.91	0.71	0.59	0.49	0.37	0.38	2.18	2.23	1.38	0.75	1.83	1.43	1.54	1.30	0.98	1.02
Total Emissions (g/s)																				
CO	3.26E-1	3.39E-1	3.50E-1	1.93E-1	2.87E-1	3.62E-1	7.03E-1	5.73E-1	4.28E-1	4.40E-1	6.51E-1	6.77E-1	7.01E-1	3.87E-1	5.74E-1	7.23E-1	1.41E+0	1.15E+0	8.56E-1	8.80E-1
NOx	4.24E-1	4.37E-1	3.62E-1	2.40E-1	4.79E-1	4.31E-1	1.28E+0	1.02E+0	7.60E-1	7.74E-1	8.47E-1	8.73E-1	7.24E-1	4.80E-1	9.58E-1	8.63E-1	2.56E+0	2.04E+0	1.52E+0	1.55E+0
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
SO2	1.37E-1	1.40E-1	8.70E-2	4.75E-2	1.15E-1	8.99E-2	7.48E-2	6.18E-2	4.63E-2	4.79E-2	2.74E-1	2.81E-1	1.74E-1	9.50E-2	2.30E-1	1.80E-1	1.94E-1	1.64E-1	1.23E-1	1.29E-1
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

Case	1.a	1.b	1.c	1.d	1.e	1.f	1.g	1.h	1.i	1.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
AERMOD v15181 x/Q results																				
1-hr High (X/Q)	15.66034	14.96658	21.92986	23.33556	17.25131	18.49369	13.07891	14.83283	16.85616	15.66739	10.41756	10.21668	14.67645	16.57123	11.07668	13.94554	7.92593	9.84121	10.76017	10.53627
1-hr High (X/Q) (5yr avg)	14.87002	14.27404	18.79922	20.18789	16.31255	17.72318	11.91931	13.70885	15.63064	14.96134	9.57774	9.32426	13.69596	15.19876	10.65297	12.37682	7.32726	8.91304	10.30269	9.66097
3-hr High (X/Q)	12.53417	11.21810	15.24443	17.40613	13.21904	14.65051	10.02928	10.80085	12.48874	12.70052	7.93795	7.50462	10.30329	12.31795	8.92832	10.03047	6.5906	7.67809	8.75536	8.47666
8-hr High (X/Q)	9.84960	9.53097	12.90397	14.24852	10.71368	12.01151	8.82870	10.06146	11.15213	10.80960	7.12083	6.89334	10.15131	10.94574	7.91071	9.13003	6.249	7.509	8.31969	8.07105
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)																				
1-hr NOx	6.30083	6.23259	6.80117	4.84726	7.81338	7.64547	**15.23136**	14.00604	11.87395	11.58050	8.11669	8.14266	9.90983	7.29867	10.20512	10.67829	**18.72661**	18.21253	15.65306	14.95572
1-hr CO	5.10066	5.06794	7.68506	4.51193	4.94890	6.68750	**9.19446**	8.49381	7.21541	6.89302	6.78612	6.91909	10.28638	6.40809	6.35515	10.08568	11.14384	**11.27086**	9.21195	9.27107
8-hr CO	3.20807	3.22735	4.52204	2.75495	3.07344	4.34348	**6.20656**	5.76155	4.77376	4.75579	4.63859	4.66841	7.11481	4.23271	4.53870	6.60301	**8.78608**	8.59984	7.12262	7.10187
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
1-hr SO2	**2.03807**	2.00426	1.63561	0.95912	1.87752	1.59294	0.89171	0.84665	0.72433	0.71690	**2.62543**	2.61849	2.38322	1.44417	2.45225	2.22483	1.41939	1.45753	1.27191	1.24531
3-hr SO2	**1.71792**	1.57516	1.32633	0.82696	1.52147	1.31677	0.75031	0.66706	0.57873	0.60857	**2.17594**	2.10749	1.79286	1.17044	2.05524	1.80306	1.27669	1.25558	1.08088	1.09265
24-hr SO2	**1.32237**	1.31702	1.08953	0.63715	1.19986	1.03526	0.64594	0.60616	0.50346	0.50455	1.58722	1.45211	1.67325	0.99193	**1.72382**	1.58627	0.81247	1.05139	0.98634	0.98144

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}	NOx
	(m)	(m)	Height (m)	Diam(m)	(m/s)	(ºK)	(g/s)	(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	9.6
BABCOCK & WILSON #3	328760.64	4692244.83	53.3	2.92	9.45	460.9	1.22	1.22	14.4
TURBOPOWER CTG#1	328659.10	4692298.20	9.9	4.08	39.62	838.7	0.47	0.47	14.9
COMBINED CYCLE TURBINE	328722.3	4692228.1	76.2	5.11	28.96	394.3	6.3	6.3	6.9
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	0.54
Turbine – ULSD; No Duct Fire (CHP) –AN	325795.40	4692345.70	33.5	1.25	19.07	432.6	0.38	0.38	0.22
STACK 2 (Boilers 11 and 12)	325832.90	4692316.60	48.8	3.04	12.50	435.9	8.65	8.65	20.2
STACK2 (Boilers 6 and 13)	325806.80	4692328.70	45.7	3.66	10.36	469.3	3.53	3.53	10.2
MATEP									
STACK (TWO IDENTICAL FLUES)	326436.20	4689289.80	96.0	4.23	11.31	433.3	4.29	4.29	107.6
*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	173.6
CTG/HRSG #81	329943.60	4695254.20	93.0	6.25	22.04	365.0	4.1	4.1	2.7
CTG/HRSG #82	329944.80	4695263.20	93.0	6.25	22.04	365.0	4.1	4.1	2.7
CTG/HRSG #93	329957.30	4695325.40	93.0	6.25	22.04	365.0	4.1	4.1	2.7
CTG/HRSG #94	329958.90	4695333.60	93.0	6.25	22.04	365.0	4.1	4.1	2.7
ROLLS ROYCE CTG	329630.00	4695256.40	9.1	3.66	12.8	810.9	2.8	2.8	9.0
Veolia Kneeland Street									
Stack 1	330471.67	4690635.24	81.4	3.51	15.24	505.4	N/A	N/A	35.3
Stack 2	330484.79	4690631.42	81.4	3.96	15.24	505.4	N/A	N/A	38.8
Logan Airport									
Keeler Boiler 1	333535.80	4692680.30	17.4	1.08	10.67	435.9	N/A	N/A	7.3
Keeler Boiler 2	333533.14	4692676.97	17.4	1.08	10.67	435.9	N/A	N/A	6.7
Keeler Boiler 3	333531.47	4692674.47	17.4	1.08	10.67	435.9	N/A	N/A	4.99

* UTM Coordinates are NAD83, Zone 19N

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 Increment Expanding 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

ATTACHMENT D

Calculations of Emission Rates for Non-Criteria Pollutant Modeling

MIT CHP EVALUATION: HAP EMISSIONS - New Turbines

	Worst Case X/Q			
	24-hr		Annualized	
	Nat. Gas	ULSD	Natural Gas	ULSD
CT Heat Input (MMBtu/hr LHV)	90.0	134.4	178	233
HHV/LHV conversion	1.109	1.063	1.109	1.063
CT Heat Input (MMBtu/hr HHV)	99.81	142.87	197.85	247.68
Turbine Max. Hours of Operation:	8760	168	8760	168

HAP Emissions for Gas Firing Per Turbine

	Combustion Turbine Emission Rates Per Turbine						
Pollutant	**Emission Factor**	**Units**	**Notes**	**Short-Term (lb/hr)**	**Short-Term (g/sec)**	**Annulized (tpy)**	**Annualized (lb/hr)**
1,3-Butadiene	4.3E-07	lb/MMBtu	A	4.3E-05	5.4E-06	3.7E-04	8.5E-05
Acetaldehyde	4.0E-05	lb/MMBtu	A	4.0E-03	5.0E-04	3.5E-02	7.9E-03
Acrolein	6.4E-06	lb/MMBtu	A	6.4E-04	8.1E-05	5.5E-03	1.3E-03
Benzene	1.2E-05	lb/MMBtu	A	1.2E-03	1.5E-04	1.0E-02	2.4E-03
Naphthalene	1.3E-06	lb/MMBtu	A	1.3E-04	1.6E-05	1.1E-03	2.6E-04
Ethylbenzene	3.2E-05	lb/MMBtu	A	3.2E-03	4.0E-04	2.8E-02	6.3E-03
Formaldehyde	7.1E-04	lb/MMBtu	A	7.1E-02	8.9E-03	6.2E-01	1.4E-01
Total PAH	2.2E-06	lb/MMBtu	A	2.2E-04	2.8E-05	1.9E-03	4.4E-04
Propylene Oxide	2.9E-05	lb/MMBtu	A	2.9E-03	3.7E-04	2.5E-02	5.7E-03
Toluene	1.3E-04	lb/MMBtu	A	1.3E-02	1.6E-03	1.1E-01	2.6E-02
Xylenes	6.4E-05	lb/MMBtu	A	6.4E-03	8.1E-04	5.5E-02	1.3E-02

Calculation Notes

A = Emission Factor Source: AP-42, Table 3.1-3, 5th edition (April 2000)

HAP Emissions for ULSD Firing Per Turbine

	Combustion Turbine Emission Rates Per Turbine						
Pollutant	**Emission Factor**	**Units**	**Notes**	**Short-Term (lb/hr)**	**Short-Term (g/sec)**	**Annulized (tpy)**	**Annualized (lb/hr)**
1,3-Butadiene	1.6E-05	lb/MMBtu	A	2.3E-03	2.9E-04	3.3E-04	4.0E-03
Benzene	5.5E-05	lb/MMBtu	A	7.9E-03	9.9E-04	1.1E-03	1.4E-02
Formaldehyde	2.8E-04	lb/MMBtu	A	4.0E-02	5.0E-03	5.8E-03	6.9E-02
Naphthalene	3.5E-05	lb/MMBtu	A	5.0E-03	6.3E-04	7.3E-04	8.7E-03
Total PAH	4.0E-05	lb/MMBtu	A	5.7E-03	7.2E-04	8.3E-04	9.9E-03
Arsenic	1.9E-06	lb/MMBtu	C	2.8E-04	3.5E-05	4.0E-05	4.8E-04
Beryllium	3.1E-07	lb/MMBtu	B	4.4E-05	5.6E-06	6.4E-06	7.7E-05
Cadmium	2.5E-06	lb/MMBtu	C	3.6E-04	4.6E-05	5.3E-05	6.3E-04
Chromium	1.1E-05	lb/MMBtu	B	1.6E-03	2.0E-04	2.3E-04	2.7E-03
Lead	1.4E-05	lb/MMBtu	B	2.0E-03	2.5E-04	2.9E-04	3.5E-03
Manganese	7.9E-04	lb/MMBtu	B	1.1E-01	1.4E-02	1.6E-02	2.0E-01
Mercury	1.2E-06	lb/MMBtu	B	1.7E-04	2.2E-05	2.5E-05	3.0E-04
Nickel	4.6E-06	lb/MMBtu	B	6.6E-04	8.3E-05	9.6E-05	1.1E-03
Selenium	2.5E-05	lb/MMBtu	B	3.6E-03	4.5E-04	5.2E-04	6.2E-03

A = Emission Factor Source: AP-42, Table 3.1-4, 5th edition (April 2000)
B = Emission Factor Source: AP-42, Table 3.1-5, 5th edition (April 2000)

C = CATEF Turbine - Cogeneration (SCC: 20200103), Maximum

Pollutant	**Short-Term Gas (lb/hr)**	**Short-Term Oil (lb/hr)**	**Max Short-Term (lb/hr)**	**Two Turbines Max Short-Term (lb/hr)**	**Two Turbines Short-Term (gram/sec)**
1,3-Butadiene	4.3E-05	2.3E-03	2.3E-03	4.6E-03	5.8E-04
Acetaldehyde	4.0E-03		4.0E-03	8.0E-03	1.0E-03
Acrolein	6.4E-04		6.4E-04	1.3E-03	1.6E-04
Benzene	1.2E-03	7.9E-03	7.9E-03	1.6E-02	2.0E-03
Naphthalene	1.3E-04	5.0E-03	5.0E-03	1.0E-02	1.3E-03
Ethylbenzene	3.2E-03		3.2E-03	6.4E-03	8.1E-04
Formaldehyde	7.1E-02	4.0E-02	7.1E-02	1.4E-01	1.8E-02
Total PAH	2.2E-04	5.7E-03	5.7E-03	1.1E-02	1.4E-03
Propylene Oxide	2.9E-03		2.9E-03	5.8E-03	7.3E-04
Toluene	1.3E-02		1.3E-02	2.6E-02	3.3E-03
Xylenes	6.4E-03		6.4E-03	1.3E-02	1.6E-03
Arsenic		2.8E-04	2.8E-04	5.6E-04	7.0E-05
Beryllium		4.4E-05	4.4E-05	8.9E-05	1.1E-05
Cadmium		3.6E-04	3.6E-04	7.3E-04	9.2E-05
Chromium		1.6E-03	1.6E-03	3.1E-03	4.0E-04
Lead		2.0E-03	2.0E-03	4.0E-03	5.0E-04
Manganese		1.1E-01	1.1E-01	2.3E-01	2.8E-02
Mercury		1.7E-04	1.7E-04	3.4E-04	4.3E-05
Nickel		6.6E-04	6.6E-04	1.3E-03	1.7E-04
Selenium		3.6E-03	3.6E-03	7.1E-03	9.0E-04

Worst Case Yearly HAP Emissions

Total Turbine Combustion Emission Rates (2 New Turbines)							
Pollutant	Worst Case Fuel	NG Emission Factor	ULSD Emission Factor	Units	Annulized Natural Gas (lb/hr)	Annualized ULSD (lb/hr)	(tpy)
1,3-Butadiene	ULSD	4.3E-07	1.6E-05	lb/MMBtu	1.7E-04	7.9E-03	1.3E-03
Acetaldehyde	Gas	4.0E-05		lb/MMBtu	1.6E-02		6.9E-02
Acrolein	Gas	6.4E-06		lb/MMBtu	2.5E-03		1.1E-02
Benzene	ULSD	1.2E-05	5.5E-05	lb/MMBtu	4.7E-03	2.7E-02	2.1E-02
Beryllium	ULSD		3.1E-07	lb/MMBtu		1.5E-04	1.3E-05
Ethylbenzene	Gas	3.2E-05		lb/MMBtu	1.3E-02		5.5E-02
Formaldehyde	Gas	7.1E-04	2.8E-04	lb/MMBtu	2.8E-01	1.4E-01	6.1E-01
Naphthalene	ULSD	1.3E-06	3.5E-05	lb/MMBtu	5.1E-04	1.7E-02	3.5E-03
Propylene Oxide	Gas	2.9E-05		lb/MMBtu	1.1E-02		5.0E-02
Toluene	Gas	1.3E-04		lb/MMBtu	5.1E-02		2.3E-01
Xylenes	Gas	6.4E-05		lb/MMBtu	2.5E-02		1.1E-01
Total PAH	ULSD		4.0E-05	lb/MMBtu	8.7E-04	2.0E-02	5.2E-03
Arsenic	ULSD		1.9E-06	lb/MMBtu		9.6E-04	8.1E-05
Cadmium	ULSD		2.5E-06	lb/MMBtu		1.5E-04	1.3E-05
Chromium	ULSD		1.1E-05	lb/MMBtu		1.3E-03	1.1E-04
Lead	ULSD		1.4E-05	lb/MMBtu		5.4E-03	4.6E-04
Manganese	ULSD		7.9E-04	lb/MMBtu		6.9E-03	5.8E-04
Mercury	ULSD		1.2E-06	lb/MMBtu		3.9E-01	3.3E-02
Nickel	ULSD		4.6E-06	lb/MMBtu		5.9E-04	5.0E-05
Selenium	ULSD		2.5E-05	lb/MMBtu		2.3E-03	1.9E-04
							1.2E+00

New Duct Burner Nat. Gas
Duct Burner Heat Input (MMBtu/hr LHV) 121 Conservatively assumes maximum rate for duct burner, however at 24-hr Cases modeled
Duct Burner Heat Input (MMBtu/hr HHV) 134 duct buner usage is anticipated to be lower.

Duct Burner Max. Hours of Operation: 8760

Duct Burner Emission Rates (2 Burners)						
Pollutant	Emission Factor	Units	Notes	(lb/hr)	(g/sec)	(tpy)
Benzene	2.10E-03	lb/10^6 scf	C	5.53E-04	6.97E-05	2.42E-03
Dichlorobenzene	1.20E-03	lb/10^6 scf	C	3.16E-04	3.99E-05	1.38E-03
Formaldehyde	7.50E-02	lb/10^6 scf	C	1.97E-02	2.49E-03	8.65E-02
Hexane	1.80E+00	lb/10^6 scf	C	4.74E-01	5.98E-02	2.08E+00
Naphthalene	6.10E-04	lb/10^6 scf	C	1.61E-04	2.03E-05	7.04E-04
Toluene	3.40E-03	lb/10^6 scf	C	8.95E-04	1.13E-04	3.92E-03
Total POM	8.40E-05	lb/10^6 scf	C	2.21E-05	2.79E-06	9.69E-05
Arsenic	2.00E-04	lb/10^6 scf	D	5.27E-05	6.64E-06	2.31E-04
Beryllium	1.20E-05	lb/10^6 scf	D	3.16E-06	3.99E-07	1.38E-05
Cadmium	1.10E-03	lb/10^6 scf	D	2.90E-04	3.65E-05	1.27E-03
Chromium	1.40E-03	lb/10^6 scf	D	3.69E-04	4.65E-05	1.61E-03
Cobalt	8.40E-05	lb/10^6 scf	D	2.21E-05	2.79E-06	9.69E-05
Manganese	3.80E-04	lb/10^6 scf	D	1.00E-04	1.26E-05	4.38E-04
Mercury	2.60E-04	lb/10^6 scf	D	6.85E-05	8.63E-06	3.00E-04
Nickel	2.10E-03	lb/10^6 scf	D	5.53E-04	6.97E-05	2.42E-03
Selenium	2.40E-05	lb/10^6 scf	D	6.32E-06	7.97E-07	2.77E-05
						2.18E+00

Calculation Notes
C = Emission Factor Source: AP-42, Table 1.4-3, 5th edition (July 1998)
D = Emission Factor Source: AP-42, Table 1.4-4, 5th edition (July 1998)

Engine Capacity (MW):	2	
Max Operating Hours:	300	
Fuel Consumption (gal/hr):	142	http://www.dieselserviceandsupply.com/Diesel_Fuel_Consumption.asp›
Energy Density (MMBtu/gal):	0.13703	AP-42 Table 3.4-1: Note a
Fuel Use (MMBtu/hr)	19.45826	

	2 MW IC Engine Emission Rates					
Pollutant	Emission Factor	Units	Notes	(lb/hr)	(g/sec)	(tpy)
Benzene	7.76E-04	lb/MMBtu	E	1.51E-02	1.90E-03	2.26E-03
Toluene	2.81E-04	lb/MMBtu	E	5.47E-03	6.90E-04	8.20E-04
Xylenes	1.93E-04	lb/MMBtu	E	3.76E-03	4.74E-04	5.63E-04
Formaldehyde	7.89E-05	lb/MMBtu	E	1.54E-03	1.94E-04	2.30E-04
Acetaldehyde	2.52E-05	lb/MMBtu	E	4.90E-04	6.18E-05	7.36E-05
Acrolein	0.00000788	lb/MMBtu	E	1.53E-04	1.93E-05	2.30E-05
Naphthalene	1.30E-04	lb/MMBtu	E	2.53E-03	3.19E-04	3.79E-04
						4.35E-03

Calculation Notes
E = Emission Factor Source: AP-42, Table 3.4-3, 5th edition (October 1996)

Combined Total Potential HAP Emissions	
Pollutant	(tpy)
1,3-Butadiene	1.3E-03
Acetaldehyde	6.94E-02
Acrolein	1.11E-02
Benzene	2.61E-02
Dichlorbenzene	1.38E-03
Ethylbenzene	5.5E-02
Formaldehyde	6.94E-01
Hexane	2.08E+00
Naphthalene	4.61E-03
Propylene Oxide	5.0E-02
Toluene	2.30E-01
Xylenes	1.11E-01
Total PAH	5.2E-03
Total POM	9.69E-05
Arsenic	3.12E-04
Beryllium	2.7E-05
Cadmium	1.3E-03
Chromium	1.7E-03
Cobalt	9.69E-05
Lead	4.6E-04
Manganese	1.0E-03
Mercury	3.3E-02
Nickel	2.5E-03
Selenium	2.2E-04
Total HAP	3.4E+00

APPENDIX E

Acentech Noise Report

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

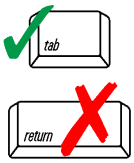
BWP AQ Sound

Submit alone and/or with Form CPA-FUEL and/or CPA-PPROCESS whenever the construction or alteration of stationary equipment (e.g. electrical generating equipment, motors, fans, process handling equipment or similar sources of sound) has the potential to cause noise, or in response to a MassDEP enforcement action citing noise as a condition of air pollution.

X262114
Transmittal Number

1191844
Facility ID (if known)

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



Introduction

When proposing sound suppression/mitigation measures, similar to the traditional "top-down" BACT process, the "top case" sound suppression/mitigation measures which deliver the lowest sound level increase above background are required to be implemented, unless these measures can be eliminated based upon technological or economic infeasibility. An applicant cannot "model out" of the use of the "top case" sound suppression/ mitigation measures by simply demonstrating that predicted sound levels at the property line when employing a less stringent sound suppression/mitigation strategy will result in a sound level increase of less than or equal to the 10 dBA (decibel, A –Weighted) above background sound level increase criteria contained in the MassDEP Noise Policy. A 10 dBA increase is the maximum increase allowed by MassDEP; it is not the sound level increase upon which the design of sound suppression/mitigation strategies and techniques should be based. Also, take into consideration that the city or town that the project is located in may have a noise ordinance (or similar) that may be more stringent than the criteria in the MassDEP Noise Policy

A. Sound Emission Sources & Abatement Equipment/Mitigation Measures

1. Provide a description of the source(s) of sound emissions and associated sound abatement equipment and/or mitigation measures. Also include details of sound emission mitigation measures to be taken during construction activities.

Two GE LM2500 combustion turbine generator (CTG) or similar and HRSG packages within new building. CTGs will have air inlet and exhaust mufflers and building ventilation systems will have attenuators. Fuel gas compressor and black start diesel generator will be in enclosures on the roof. New cooling towers with reduced-noise fans and variable frequency drives and louver barrier walls to be installed on roof of adjacent building. Sections B & C and letter report include details on planned project. Construction noise mitigation measures include: mufflers in suitable condition will be installed on all engine-driven equipment and noisier construction activities will be scheduled for regular daytime hours.

B. Manufacturer's Sound Emission Profiles & Sound Abatement Equipment

Please attach to this form the manufacturer's sound generation data for the equipment being proposed for installation, or the existing equipment as applicable. This data must specify the sound pressure levels for a complete 360° circumference of the equipment and at given distance from the equipment. Also attach information provided by the sound abatement manufacturer detailing the expected sound suppression to be provided by the proposed sound suppression equipment.

C. Plot Plan

Provide a plot plan and aerial photo(s) (e.g. GIS) that defines: the specific location of the proposed or existing source(s) of sound emissions; the distances from the source(s) to the property lines; the location, distances and use of all inhabited buildings (residences, commercial, industrial, etc) beyond the property lines; identify any areas of possible future construction beyond the property line; and sound monitoring locations used to assess noise impact on the surrounding community. All information provided in the sound survey shall contain sufficient data and detail to adequately assess any sound impacts to the surrounding community, including elevated receptors as applicable, not necessarily receptors immediately outside the facility's property line.

Continue to Next Page ►

D. Community Sound Level Criteria

Approval of the proposed new equipment or proposed corrective measures will **not** be granted if the installation:

1. Increases off-site broadband sound levels by more than 10 dBA.above "ambient" sound levels. Ambient is defined as the lowest one-hour background A-weighted sound pressure level that is exceeded 90 percent of the time measured during equipment operating hours. Ambient may also be established by other means with the consent of MassDEP.

2. Produces off-site a "pure tone" condition. "Pure tone" is defined as when any octave band center frequency sound pressure level exceeds the two adjacent frequency sound pressure levels by 3 decibels or more.

3. Creates a potential condition of air pollution as defined in 310 CMR 7.01 and the MassDEP Noise Policy.

Note: These criteria are measured both at the property line and at the nearest inhabited building.

For equipment that operates, or will be operated intermittently, the ambient or background noise measurements shall be performed during the hours that the equipment will operate and at the quietest times of the day. The quietest time of the day is usually between 1:00 a.m. and 4:00 a.m. on weekend nights. The nighttime sound measurements must be conducted at a time that represents the lowest ambient sound level expected during all seasons of the year.

For equipment that operates, or will operate, continuously and is a significant source of sound, such as a proposed power plant, background shall be established via a minimum of seven consecutive days of continuous monitoring at multiple locations with the dBA L 90 data and pure tone data reduced to one-hour averages.

In any case, consult with the appropriate MassDEP Regional Office before commencing noise monitoring in order to establish a sound monitoring protocol that will be acceptable to MassDEP.

E. Full Octave Band Analysis

The following community sound profiles will require the use of sound pressure level measuring equipment in the neighborhood of the installation. An ANSI S1.4 Type 1 sound monitor or equivalent shall be use for all sound measurements. A detailed description of sound monitor calibration methodology shall be included with any sound survey.

1. Lowest **ambient** sound pressure levels during operating hours of the equipment.

   a. At property line:

A-Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
PL-1 (61)	63	64	63	60	57	56	51	48	42	<42
PL-2 (59)	65	65	65	60	56	53	47	39	29	<29
PL-3 (63)	69	69	68	64	59	56	54	46	34	<34

E. Full Octave Band Analysis (continued)

b. At the nearest inhabited building and if applicable at buildings at higher elevation:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
R-1 (58)	62	62	64	59	56	53	45	38	26	<26
R-2 (57)	67	66	62	57	54	52	46	39	28	<28
R-3 (56)	66	66	61	57	54	51	47	37	31	<31

Note: You are required to complete sound profiles 2a and 2b only if you are submitting this form in response to a MassDEP enforcement action citing a noise nuisance condition. If this is an application for new equipment, Skip to 3.

2. Neighborhood sound pressure levels with source operating without sound abatement equipment.

a. At property line:

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

b. At the nearest inhabited building and if applicable at buildings at higher elevation:

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

Continue to Next Page ►

E. Full Octave Band Analysis (continued)

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

a. At property line:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
PL-1 (64)	76	75	71	66	61	58	53	50	45	<45
PL-2 (59)	66	65	65	60	56	53	47	39	29	<29
PL-3 (63)	69	69	68	64	59	56	54	46	34	<34

b. At nearest inhabited building and if applicable at buildings at higher elevations:

A- Weighted	31.5	63.0	125	250	500	1K	2K	4K	8K	16K
R-1 (58)	63	63	64	59	56	53	45	38	28	<28
R-2 (57)	67	66	62	57	54	52	46	39	28	<28
R-3 (56)	66	66	61	58	54	51	47	37	31	<31

Note: MassDEP may request that actual measurements be taken after the installation of the noise abatement equipment to verify compliance at all off-site locations.

F. Professional Engineers Stamp

The seal or stamp and signature of a Massachusetts Registered Professional Engineer (P.E.) must be entered below. Both the seal or stamp impression and the P.E. signature must be original. This is to certify that the information contained in this Form has been checked for accuracy, and that the design represents good air pollution control engineering practice.

James D. Barnes
P.E. Name (Type or Print)

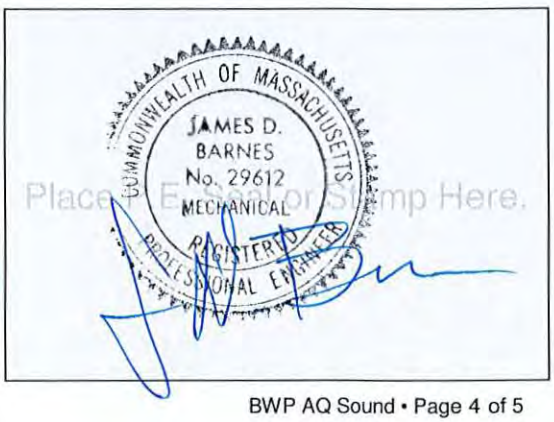
P.E. Signature

Supervisory Noise Consultant
Position/Title

Acentech Incorporated
Company

10/5/2015
Date (MM/DD/YYYY)

29612
P.E. Number



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

BWP AQ Sound

Submit alone and/or with Form CPA-FUEL and/or CPA-PPROCESS whenever the construction or alteration of stationary equipment (e.g. electrical generating equipment, motors, fans, process handling equipment or similar sources of sound) has the potential to cause noise, or in response to a MassDEP enforcement action citing noise as a condition of air pollution.

X262114
Transmittal Number

1191844
Facility ID (if known)

G. Certification by Responsible Official

The signature below provides the affirmative demonstration pursuant to 310 CMR 7.02(5)(c)8 that any facility(ies) in Massachusetts, owned or operated by the proponent for this project (or by an entity controlling, controlled by or under common control with such proponent) that is subject to 310 CMR 7.00, et seq., is in compliance with, or on a MassDEP approved compliance schedule to meet, all provisions of 310 CMR 7.00, et seq., and any plan approval, order, notice of noncompliance or permit issued thereunder. This Form must be signed by a Responsible Official working at the location of the proposed new or modified facility. Even if an agent has been designated to fill out this Form, the Responsible Official must sign it. (Refer to the definition given in 310 CMR 7.00.)

I certify that I have personally examined the foregoing and am familiar with the information contained in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including possible fines and imprisonment.

William VanSchalkwyk
Responsible Official Name (Type or Print)

William VanSchalkwyk
Responsible Official Signature

Managing Director, EHS Programs
Responsible Official Title

MIT
Responsible Official Company/Organization Name

12/14/2015
Date (MM/DD/YYYY)

Description of Sound Emission Profile and Sound Abatement Equipment [Section B of MassDEP Form BWP AQ Sound (Noise Form)]

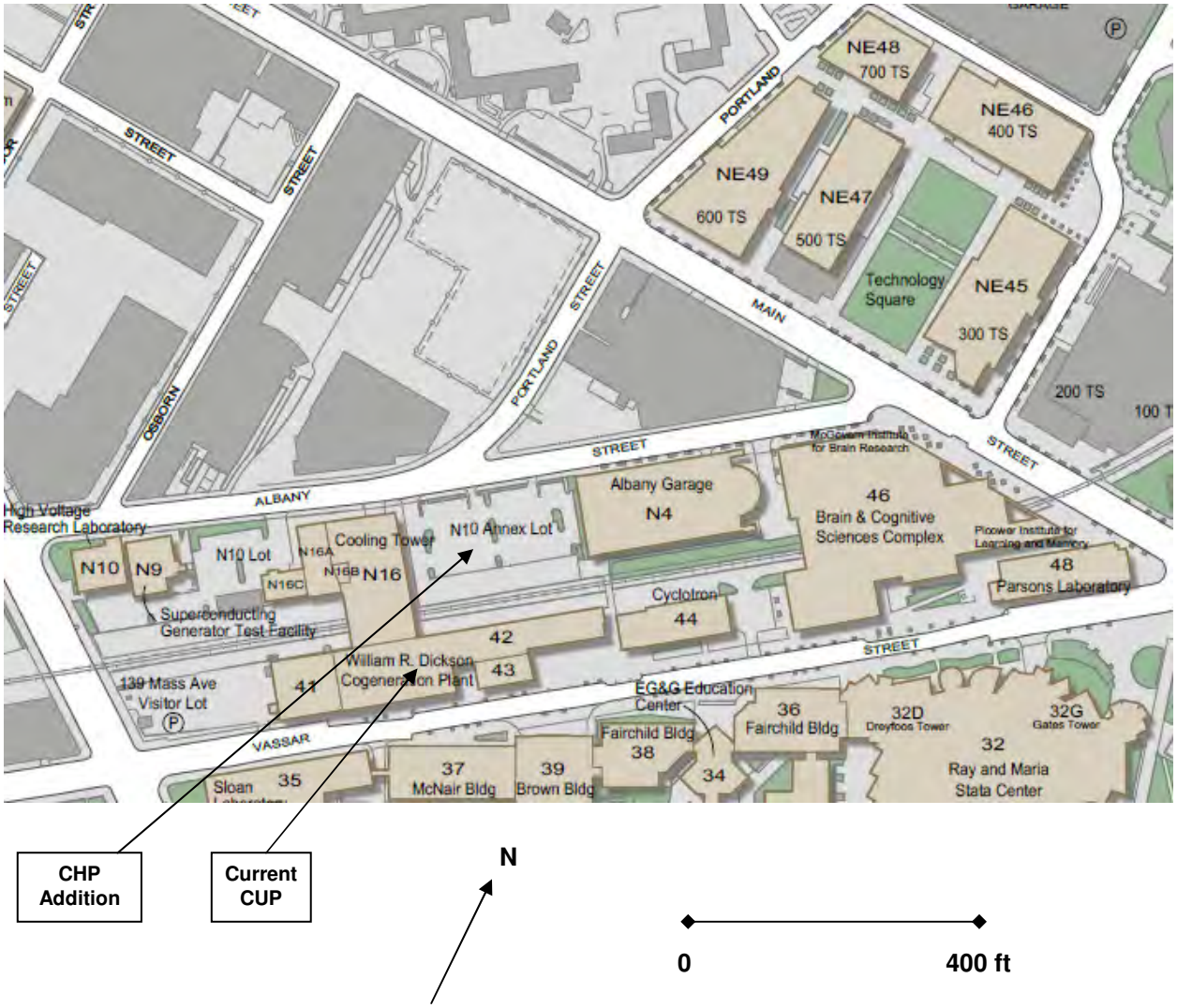
OPERATION SOUND AND MITIGATION MEASURES

The sound emissions from the entire CHP addition, which includes the combustion turbine generator packages, heat recovery steam generators, fuel gas compressors, chillers, new cooling towers, cold start generator, support equipment, and new building, will be specified, designed, and operated to address compliance with the MassDEP Noise Criteria and the City of Cambridge Noise Standards. Abatement methods to be employed to control the sound of the CHP addition will include the following:

- Combustion turbine generator sets will be installed in sound-attenuated enclosures.
- Majority of cogeneration equipment will be installed in an acoustically-designed building with appropriate treatments for building ventilation systems and access openings.
- Mufflers will be installed as necessary on the gas turbine air intake, gas exhaust, and turbine enclosure ventilation systems.
- Mufflers will be installed as needed on non-emergency steam vents.
- Reduced-noise lube oil cooler model will be used or sound barrier walls will be installed for the standard model as needed.
- The fuel gas compressor and drive motor will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.
- The cold start diesel generator will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.
- New mechanical draft wet cooling towers will include reduced-noise fans with variable frequency drives and louvered barrier walls as required to meet sound ordinance.

The major CHP equipment will be located within the southern section of the building toward the existing railroad tracks and other support systems and administrative spaces will be located on the northern section of the building toward Albany Street. As noted above, the CTG will be enclosed and located within the new building and the fuel gas compressor and cold start diesel generator will be installed in sound-attenuated enclosures located on the roof with treated ventilation air paths. The average sound levels around the enclosed CTG and the balance of the CHP area are estimated to be 85 dBA or less. The building walls and roof will have a minimum surface weight of 8 psf or a composite structure that can provide a minimum Sound Transmission Class (STC) rating of STC 30. The equipment and building air ventilation paths will include treatments (e.g., mufflers, lined ducts, acoustic louvers, and local barriers) with suitable sound attenuation; and the major ventilation openings will be on the south wall of the building facing the railroad tracks and shielded from direct line-of-sight to the community. The personnel doors and overhead doors that directly access the main CHP room from outdoors will be specified with an appropriate STC rating. The overall design and construction of the building shell will aim to achieve 55 to 60 dBA directly outside the building walls facing the community.

Figure A.
Drawing Showing Current MIT Central Utilities Plant (CUP) and Planned Combined Heat and Power (CHP) Addition.
[Section C of MassDEP Form BWP AQ Sound (Noise Form)]



CHP Addition

Current CUP

N

0 400 ft

Figure B.
Aerial Photograph Showing Planned Location for MIT CHP Addition and Distances to Property Line (PL) and Residential (R) Locations for August 2014 Ambient Sound Survey and Analysis.
[Section C of MassDEP Form BWP AQ Sound (Noise Form)]

Six short-term measurement locations and one long-term measurement location (marked by *); ambient sound measured at long-term Location R-1A is representative of sound at Location R-1.

Location	Approximate Distance from Project Center (ft)
PL-1 (North)	70
PL-2 (Northeast)	650
PL-3 (Southwest)	650
R-1 (Newtowne Ct. Apts.)	580
R-2 (MIT Housing)	1200
R-3 (MIT Housing)	1100

N

Acentech Incorporated
33 Moulton Street
Cambridge, MA 02138

Telephone: 617-499-8018
Facsimile: 617-499-8074
E-mail: jbarnes@acentech.com

Acentech

5 October 2015

Massachusetts Institute of Technology
77 Massachusetts Ave, NE49-2021Q
Cambridge, MA 02139

Subject: Community Sound Study
Planned MIT Second Century Plant Upgrade
Cambridge, MA
Acentech Project No. 624469

Attention: John Engle
Director, Utility Projects

Dear Mr. Engle:

INTRODUCTION

Massachusetts Institute of Technology (MIT) proposes to upgrade their existing Central Utilities Plant (CUP) on Vassar Street at the Cambridge, MA campus to house additional CHP (Combined Heat and Power) equipment. The new equipment is designed to produce up to 44 MW of electrical power and 320,000 pph of thermal energy, using heat recovery steam generators, for distribution to the Institute's campus. The CHP addition will span the railroad tracks and be adjacent to the east side of Building N16. The additional building space will be developed in the area currently designated as the N10 Annex parking lot. The project will include the installation of two General Electric LM2500 combustion turbine generators (CTG) or similar equipment and heat recovery steam generator (HRSG) packages, two chillers, a cold start diesel generator, coolers, pumps, mechanical draft wet cooling towers, and other support equipment. Since the available gas pressure could fall below the minimum required pressure, one new high pressure fuel gas compressor will also be installed. Figure 1 shows the CHP project location on an aerial photograph and Figure 2 displays 3-D sketches of the existing project site and the site with the proposed CHP addition. Major equipment items for the new plant include:

- Two (2) CTGs with water-cooled generators
- Two (2) HRSGs with duct burners and SCR and CO catalysts
- Two (2) lube oil coolers and pumps
- Inlet filter housings with heating & cooling
- One (1) fuel gas compressor skid
- Liquid fuel storage and delivery systems
- 2 MW reciprocating internal combustion engine (RICE) cold start diesel generator
- 1000 CFM water-cooled air compressor
- Two (2) 2500 ton electric chillers
- Removal of seven (7) mechanical draft cooling tower units
- Addition of three (3) mechanical draft cooling tower units

The current 20 MW ABB GT-10 CTG and HRSG system, which was installed in 1994 at the existing CUP, will be retired following commissioning of the new cogeneration plant. In addition, several existing cooling tower units will be retired following the addition of new rooftop units.

The CHP Project team met with representatives of the Massachusetts Department of Environmental Protection (MassDEP) on 7/29/2014 and discussed several issues, including the sound study being conducted to support the project's Air Permit Application. It was agreed that the Project team would submit an ambient survey plan for MassDEP's review and comment, meet with MassDEP representatives and tour the project site and nearby community, assess compliance of the MIT's fleet of emergency generators and engine-driven water pumps, and where indicated, recommend noise mitigation for the existing emergency units.

To date, Acentech Incorporated has reviewed project information, met with MassDEP at the project site and reviewed our study plan, performed an ambient sound survey of the area, and developed estimates of the property line and off-site sound levels associated with the proposed new CHP plant. In addition, the study team has conducted a sound survey of all of the MIT emergency generators and diesel engine-driven water pumps, assessed compliance with the MassDEP noise criteria, and developed noise control recommendations. The pertinent findings of our study for the CHP plant are summarized in this letter report. The results of our study for the existing emergency power and diesel engine-driven water pump units are presented in a separate report.

EXISTING ACOUSTIC ENVIRONMENT

Acentech conducted an ambient sound survey to characterize the existing land uses, sound sources, and background acoustic environment in the area. The program included long-term continuous measurements collected over weekday and weekend periods with an automatic monitor and shorter-term samples obtained on two nights with a portable precision sound level meter.

Figure 3 is an aerial photograph that shows the area around the proposed new CHP Plant and identifies representative residential (R) and property line (PL) sound measurement locations. We collected ambient sound data during a nominal 14-day period between 5 and 20 August 2014. The long-term data show the repetitive day and night variations in the background sound levels in the area and the short-term data characterize the background acoustic environment during typically quieter nighttime periods.

The overall A-weighted sound levels and spectra were measured continuously with an automatic monitor at the following location as shown on Figures 3 and 4:

- R-1A -- N of project site across Main Street from the nearest residences

In addition, we performed short-term sampling of the overall A-weighted sound levels and spectral data and observed sound sources during the nighttime hours at the six locations on Figure 3:

- PL-1 -- N of project site across Albany Street
- PL-2 -- NE of project site at Albany Street and Main Street
- PL-3 -- SW of project site at Albany Street and Massachusetts Avenue
- R-1 -- N of project site at nearest residences on Main Street (Newtowne Court Apartments)
- R-2 -- W of project site at MIT housing on Massachusetts Avenue (MIT housing)
- R-3 -- SW of project site at MIT housing at Albany Street and Cross Street (MIT housing)

We collected short-term ambient sound measurements and observations at the above six locations on

Friday and Saturday nights (8-9 August and 9-10 August 2014).

As Figure 3 and the above list indicate, residential areas are located to the north, west, and southwest of the project site, while the nearest property lines are directly across Albany Street to the north of the site and farther away on Albany Street to the northeast and southwest of the site. We expect that a new multi-story building that is currently under construction on the MIT-owned property between the project site and Location R-1 will provide significant shielding of project sound that may propagate toward the community near Location R-1.

Table 1 lists the instruments that we employed for the ambient measurements. Each instrument was laboratory-calibrated within the past year, and field-calibrated with an acoustic calibrator before and after the measurements. The microphone for each instrument was fitted with a windscreen and mounted at a nominal height of five feet above the ground. For this survey we programmed the continuous monitor at Location R-1A to collect overall A-weighted sound levels and spectral data (1/3-octave band sound pressure levels) and to store the statistical values (Lmax, Lmin, L1, L10, L50, L90, and Leq) at ten-minute intervals. Similar statistical spectral data, plus octave band data, were collected for a one-hour period with a portable meter at each of the six property line and residential locations. Weather conditions during the overall survey from 5 to 20 August 2014 were seasonal with typical temperatures of 75 to 85ºF during the day and 60 to 65ºF during the night, calm to moderate winds, and one stormy period on 13 August 2014. The sound data and observations collected during our survey characterize the typical existing acoustic environment in the area.

Long-Term Data
Figure 5 illustrates the changes in ambient sound levels measured at the long-term monitor Location R-1A over the day and night periods, and specifically, present the Leq, L1, and L90 A-weighted sound levels for each 10-minute interval. The energy-average Leq sound levels include both the steady background sounds (e.g., distant traffic and building ventilation equipment) plus the short-term intrusive sounds (e.g., horn blast or local car passby). The L1 sound levels represent the nominal maximum sounds, such as local traffic sounds, that occurred for at least 1% of each interval (i.e., six seconds of each 10-minute interval). The L90 sound levels characterize the lowest background, or residual sound level exceeded for 90% of the time of each interval (i.e., nine minutes of each 10-minute interval). The L90 sound level occurs when short-term intrusive sound sources, such as local traffic passbys or aircraft flyovers, are absent and the sound level returns to a lower residual value. This figure reveals that the nighttime sound levels were generally lower than the daytime levels. The sound levels at these locations were typically due to sounds of building ventilation equipment in the area and distant and local road traffic. The data on Figure 5 indicate that the measured L90 sound levels ranged down to about 59 to 61 dBA at Location R-1A during the nighttime periods. In addition, this figure notes that local construction activity began during the second week, which increased the daytime sound levels measured at this location.

Short-Term Data
Table 2 summarizes the residual (L90) sound levels that were measured with a portable meter over a nighttime hour at each location. As previously noted, the L90 data are the levels exceeded for 90% of the sampling periods (i.e., 54 minutes of each hour) and represent the background, or residual, sound levels. The data in Table 2 indicate existing residual sound levels that ranged from 59 to 63 dBA at the property line Locations PL-1 to PL-3 and from 56 to 58 dBA at the residential Locations R-1 to R-3. The primary sound sources observed at these locations included: building ventilation equipment, local and distant road traffic, and MIT building and cooling tower equipment. Our observations did not indicate any unusual

activities in the area during the survey.

PROJECT SOUND CRITERIA

During the permitting phase it is necessary to determine the degree of sound reduction required for the proposed project. This is based upon estimates of the sound that will propagate from the facility and the sound level criteria appropriate for the offsite neighborhood. The sound criteria for this project will address the following factors:

- Ambient or background sound levels during the quieter times
- Type of neighborhood – residential, business, or industrial
- Character of sound generated by the proposed facility – sound pressure level and spectrum
- State and Local noise requirements

Depending on the major equipment and noise control selected for a project, a typical cogeneration facility can emit tonal and/or broadband sounds, low frequency sound, and steady and/or intermittent sounds that are noticeable in the community. The City of Cambridge and the MassDEP have noise requirements that protect residents from excessive sound.

City of Cambridge Noise Requirements
We understand that the requirements in Title 8, Chapter 8.16, NOISE CONTROL of the City of Cambridge Code of Ordinances apply to the project. The following table lists the local noise standards for different receptor land uses. These standards are enforced only for the source sound levels as a project owner has no control over the ambient sound levels. Since the cogeneration facility will operate continuously, its design should address the more stringent nighttime noise standards for the nearest residential receptors (50 dBA) and commercial receptors (65 dBA) in the surrounding area.

CITY OF CAMBRIDGE ZONING DISTRICT NOISE STANDARDS (ref: Table 8.16.060E)
Maximum Allowable Octave Band Sound Pressure Levels (dB)

Octave Band Center Frequency (Hz)	Residential Area		Residential in Industrial		Commercial Area	Industry Area
	Daytime	Other Times	Daytime	Other Times	Anytime	Anytime
31.5	76	68	79	72	79	83
63	75	67	78	71	78	82
125	69	61	73	65	73	77
250	62	52	68	57	68	73
500	56	46	62	51	62	67
1,000	50	40	56	45	56	61
2,000	45	33	51	39	51	57
4,000	40	28	47	34	47	53
8,000	38	26	44	32	44	50

Single Number (dBA)

Equivalent (dBA)	60	50	65	55	65	70

Although the CHP Project does not include an emergency generator, we understand based on discussions with the City of Cambridge that an emergency generator in a commercial area with no residences nearby does not need to meet the City's noise requirements. And if there is a nearby residence, the emergency generator is exempt from the ordinance as long as it is tested during daytime hours.

Commonwealth of Massachusetts
The Commonwealth of Massachusetts has enacted regulations for the control of air pollution (310 CMR 7.10). To enforce these regulations, MassDEP has issued guidelines that encourage the use of reasonable noise control measures and limit the level of industrial noise in residential areas as follows: a) not to increase the residual ambient sound level by more than 10 dBA and b) not to produce a pure tone condition where the sound pressure level in one octave band exceeds the levels in the two adjacent octave bands by 3 dB or more.

MassDEP has also clarified the application of its noise guidelines in an update on its website (ref: http://www.mass.gov/dep/air/laws/noisepol.htm). The website information includes a section - "Where Are MassDEP's Noise Criteria Applied?" - that states:

> "The MassDEP noise pollution policy describes criteria that MassDEP uses to evaluate noise impacts at both the property line and the nearest occupied residence or other sensitive receptor. When noise is found to be a nuisance or a threat to health, MassDEP requires the source to mitigate its noise. Noise levels that exceed the criteria at the source's property line by themselves do not necessarily result in a violation or a condition of air pollution under MassDEP regulations (see 310 CMR 7.10 U). The agency also considers the effect of noise on the nearest occupied residence and/or building housing sensitive receptors:
>
> - In responding to complaints, MassDEP measures noise levels at the complainant's location and at other nearby locations that may be affected (e.g., residences and/or buildings with other sensitive receptors). If the noise level at a sensitive receptor's location is more than 10 dBA above ambient, MassDEP requires the noise source to mitigate its impact.
> - A new noise source will be required to mitigate its sound emissions if they are projected to cause the broadband sound level at a residence or building housing sensitive receptors to exceed ambient background by more than 10 dBA.
> - A new noise source that would be located in an area that is not likely to be developed for residential use in the future (e.g., due to abutting wetlands or similarly undevelopable areas), or in a commercial or industrial area with no sensitive receptors may not be required to mitigate its noise impact on those areas, even if projected to cause noise levels at the facility's property line to exceed ambient background by more than 10 dBA. However, a new noise source that would be located in an area in which housing or buildings containing other sensitive receptors could be developed in the future may be required to mitigate its noise impact in these areas.
>
> This policy has been designed to protect affected residents and other sensitive occupants of nearby property, but not necessarily uninhabited areas in and around the source's property. Sources of noise may need to implement mitigation if residences or buildings occupied by sensitive receptors are developed where they may be affected by the source's noise."

OVERALL PROJECT SOUND CRITERIA

We recommend that the CHP Project be designed to meet the following sound criteria, which address the City of Cambridge Noise Standards, the MassDEP Noise Guidelines, and potential contributions from other MIT sources:

- 62 dBA - maximum sound level of CHP addition at property lines of nearest non-MIT properties (criteria aims to comply with associated nighttime residential octave band sound pressure levels in the Cambridge Noise Standards or be similar to existing ambient sound spectra, and as stated above,

to allow for sounds from non-CHP sources at MIT);

- 47 dBA - maximum sound level of new CHP addition at the community residences (and aim to comply with associated nighttime residential octave band sound pressure levels in the Cambridge Noise Standards or be similar to existing ambient sound spectra);

- No significant tonal sounds at community residences; and

- 55 dBA - maximum sound levels at the community residences during transient startup and shutdown activities.

OPERATION SOUND AND MITIGATION MEASURES

Abatement methods to be employed to control the sound of the cogeneration project will include the following:

- Combustion turbine generator sets will be installed in sound-attenuated enclosures.

- Majority of cogeneration equipment will be installed in an acoustically-designed building with appropriate treatments for building ventilation systems and access openings.

- Mufflers will be installed as necessary on the gas turbine air intake, gas exhaust, and turbine enclosure ventilation systems.

- Mufflers will be installed as needed on non-emergency steam vents.

- Reduced-noise lube oil cooler model will be used or sound barrier walls will be installed for the standard model as needed.

- The fuel gas compressor and drive motor will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.

- The cold start diesel generator will be installed in a sound-attenuated enclosure located on the roof with treated ventilation air paths.

- New mechanical draft wet cooling towers will include reduced-noise fans with variable frequency drives and louvered barrier walls as required to meet sound ordinance.

The sound emissions from the entire CHP Project, which includes the combustion turbine generator packages, heat recovery steam generators, fuel gas compressors, chillers, new cooling towers, cold start generator, support equipment, and cogeneration building, will be specified and designed to address compliance with the MassDEP noise guidelines and City of Cambridge Noise Standards. Table 3 presents the sound estimates for the CHP addition at the nearest property line and residential locations. As noted below the table, the estimates at the nearest location (PL-1) are based on sound levels measured on the existing new cooling tower, information provided on the CHP equipment and building layout, recommended noise specification values, and the expected building design to meet the overall project sound criteria. The estimates at the other five more distant property line and community residential locations are based on the PL-1 levels with attenuation to account for distance (i.e., hemi-spherical

spreading), but with no additional attenuation associated with other factors, such as shielding by intervening buildings, air absorption, or anomalous excess attenuation.

Table 4 presents similar information as Table 3, but the estimated total sound levels include the contributions of both the CHP addition sound and the ambient sound that we measured during the night at each location. The estimates, which are based on current project information, indicate the project design criteria are in compliance with the applicable MassDEP and City of Cambridge noise requirements. The project sound estimates will be updated during the detailed design and procurement process to check and verify compliance of the acoustical design with the noise requirements.

****

I trust that this letter provides a useful summary of our study. Should you have any questions regarding our analysis or this report, please call me at 617-499-8018.

Sincerely,

James D. Barnes, P.E.
Acentech Incorporated

Figures 1 – 5
Tables 1 – 4

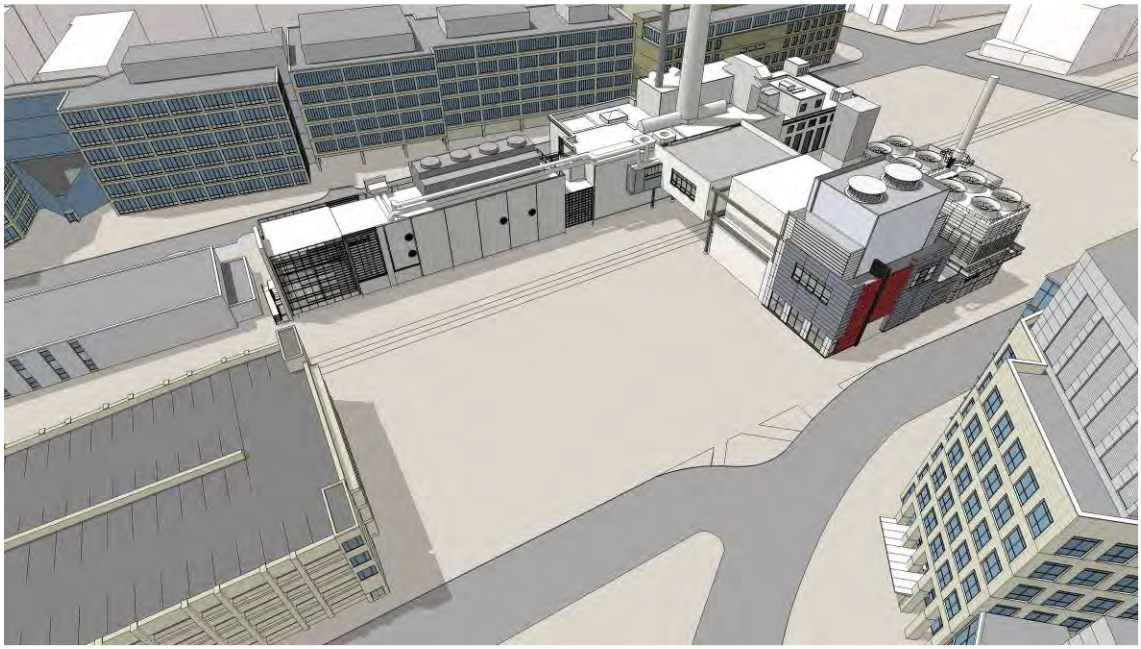
xc: M. Thornton/Vanderweil
S. Dwyer/Vanderweil

J: 624469-RGV-MIT-newCHP-100515c.doc

Figure 1.
Aerial Photograph Showing Planned Location for CHP Addition to Existing MIT CUP.

N

Figure 2.
3-D Sketches of Existing CUP and Proposed New CHP Addition.



Looking S at Existing CUP and Site of Proposed CHP Addition

Looking S at Existing CUP and Proposed CHP Addition

Figure 3.
Aerial Photograph Showing Planned Location for MIT CHP Addition and Distances to Property Line (PL) and Residential (R) Locations for August 2014 Ambient Sound Survey and Analysis.

Six short-term measurement locations and one long-term measurement location (marked by *); ambient sound measured at long-term Location R-1A is representative of sound at Location R-1.

Location	Approximate Distance from Project Center (ft)
PL-1 (North)	70
PL-2 (Northeast)	650
PL-3 (Southwest)	650
R-1 (Newtowne Ct. Apts.)	580
R-2 (MIT Housing)	1200
R-3 (MIT Housing)	1100

N

Figure 4.
Photograph Looking South from Long-Term Sound Monitoring Location R-1A toward CHP Addition Project Site.

Note: Non-residential MIT building now under construction in gravel area in foreground.

Figure 5.
Nominal Maximum (L1), Energy Average (Leq), and Residual (L90) Sound Levels Measured for 10-Minute Periods at Long-Term Monitoring Location R-1A (5 to 20 August 2014).

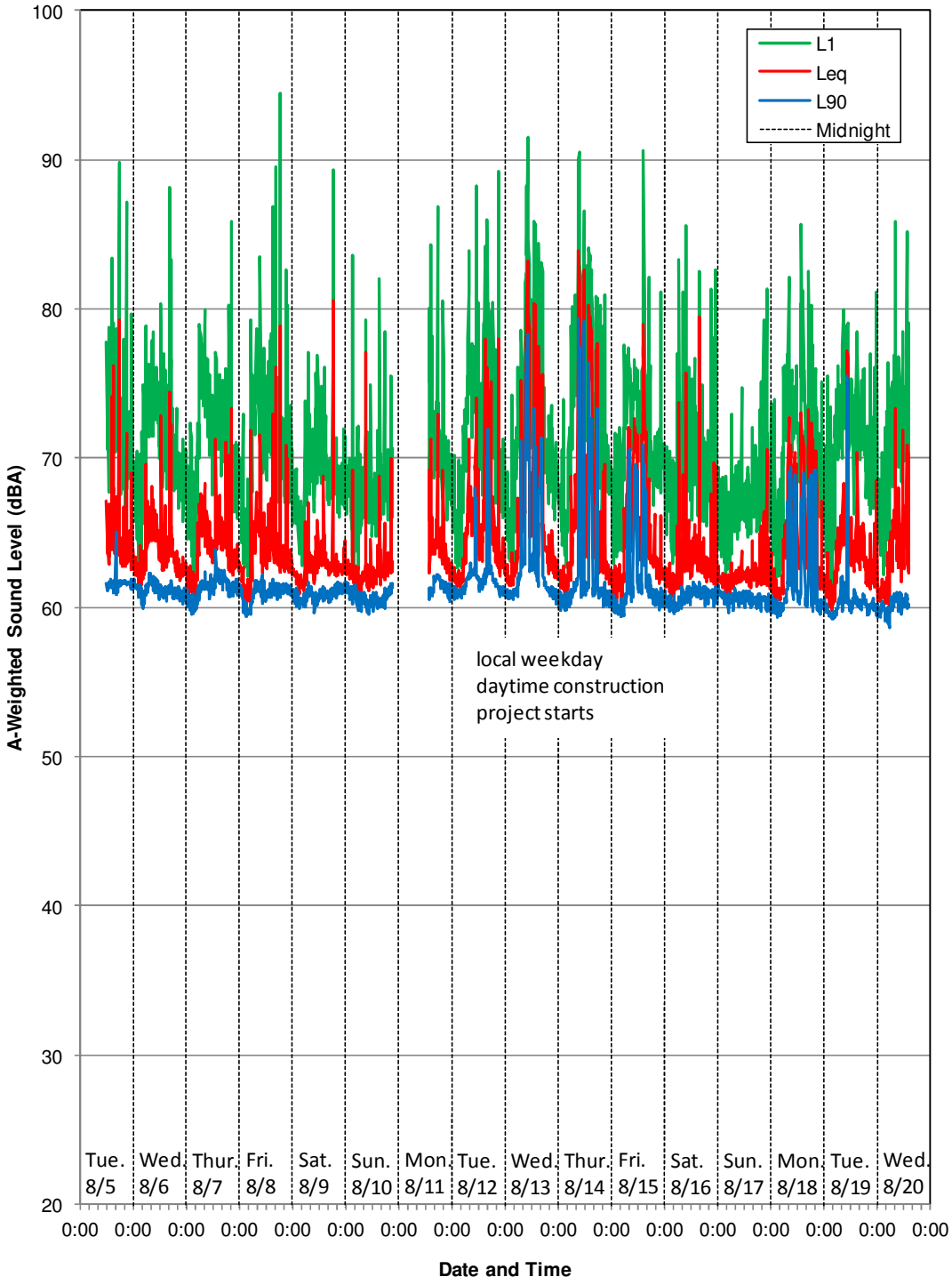


Table 1.
Type of Acoustic Instrumentation Used for Ambient Sound Measurements during 5 to 20 August 2014.

Instrument Type	Manufacturer	Model
Precision Sound Level Meter and Octave Band Analyzer	Rion	NA-28
Preamplifier	Rion	NH-23
1/2" Microphone	Rion	UC-59
Acoustic Calibrator	Rion	NC-74
Precision Sound Level Meter and Octave Band Analyzer	Rion	NL-52
Preamplifier	Rion	NH-25
1/2" Microphone	Rion	UC-59
Acoustic Calibrator	Rion	NC-74

Table 2.
Summary of Residual (One-Hour L_{90}) Sound Spectra Measured by Portable Meter at Property Line (PL) and Residential (R) Locations on Two Nights of August 2014 Ambient Sound Survey.

		Octave Band Center Frequency (Hz)									
Date	**Location**	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dBA**
8/8-9/2014	Location PL-1	63	64	63	60	57	56	51	48	42	61
11p-2:30a	Location PL-2	65	65	65	60	56	53	47	39	29	59
	Location R-1	62	62	64	59	56	53	45	38	26	58
8/9-10/2014	Location PL-3	69	69	68	64	59	56	54	46	34	63
11p-2:30a	Location R-2	67	66	62	57	54	52	46	39	28	57
	Location R-3	66	66	61	57	54	51	47	37	31	56
	Max Night	69	69	68	64	59	56	54	48	42	63
	Min Night	62	62	61	57	54	51	45	37	26	56

Measurement period at each location was one hour long.

Table 3.
Estimates of Project-Only Sound Pressure Levels and Overall A-Weighted Sound Levels at Residential Receptor (R) and Property Line (PL) Locations.

	Octave Band Center Frequency (Hz)									
Location	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dBA**
Location PL-1	76	75	70	65	59	53	48	44	41	62
Location PL-2	57	56	51	46	40	34	29	25	22	43
Location PL-3	57	56	51	46	40	34	29	25	22	43
Location R-1	58	57	52	47	41	35	30	26	23	44
Location R-2	51	50	45	40	34	28	23	19	16	37
Location R-3	52	51	46	41	35	29	24	20	17	38

Table 4.
Estimates of Total (Project + Ambient) Sound Pressure Levels and Overall A-Weighted Sound Levels at Residential Receptor (R) and Property Line (PL) Locations.

	Octave Band Center Frequency (Hz)									
Location	**31.5**	**63**	**125**	**250**	**500**	**1000**	**2000**	**4000**	**8000**	**dBA**
Location PL-1	76	75	71	66	61	58	53	50	45	64
Location PL-2	66	65	65	60	56	53	47	39	29	59
Location PL-3	69	69	68	64	59	56	54	46	34	63
Location R-1	63	63	64	59	56	53	45	38	28	58
Location R-2	67	66	62	57	54	52	46	39	28	57
Location R-3	66	66	61	58	54	51	47	37	31	56

Calculated values rounded-off to whole dB for display.

Estimates at the nearest location (PL-1) are based on sound levels measured on the existing new cooling tower, information provided on the CHP equipment and building layout, the recommended noise specification values, and the expected building design. The estimates at the other five more distant property line and community residential locations are based on the PL-1 levels with attenuation to account for distance only (i.e., hemi-spherical spreading), but with no additional attenuation to account for other factors, such as shielding by intervening buildings, air absorption, or anomalous excess attenuation.

Acentech Incorporated
33 Moulton Street
Cambridge, MA 02138

Telephone: 617-499-8018
Facsimile: 617-499-8074
E-mail: jbarnes@acentech.com

Acentech

12 January 2015 (Reissued 5 October 2015)

Massachusetts Institute of Technology
77 Massachusetts Ave, NE49-2021Q
Cambridge, MA 02139

Subject: Sound Study of Existing Emergency Generators and Fire Pumps
MIT Campus in Cambridge, MA
Acentech Project No. 624469

Attention: John Engle
Director, Utility Projects

Dear Mr. Engle:

INTRODUCTION

At your request, Acentech Incorporated conducted a sound study of MIT's current fleet of emergency generators and engine-driven fire pumps. The purpose of this study was to survey the sound of the existing emergency units, identify those not in compliance with the Massachusetts Department of Environmental Protection (MassDEP) Noise Guidelines, and as indicated, recommend noise mitigation for the units that address the guidelines.

Table 1 lists all 57 emergency generator and pump units that serve the MIT campus and summarizes the results of our survey. Between 5 August and 13 November 2014, we visited every installation with an MIT technician; reviewed the unit's design and associated noise control treatments; collected sound measurements near the unit and toward the community and potential noise-sensitive locations (e.g., off-campus and on-campus residences) during no-load or partial load operation; and measured the ambient sound levels in the area with the unit off during the day and again during the night. The units were typically located either inside of a building or in an enclosure installed on the ground or on a building rooftop. We observed that each unit had an engine exhaust muffler in operating condition. The applicable noise criteria, the pertinent results of our field measurements, and a potential course of action are summarized in this letter report.

LOCAL AND STATE NOISE CRITERIA

The City of Cambridge and the Commonwealth of Massachusetts have noise requirements that protect residents from excessive sound.

City of Cambridge Noise Requirements
Based on discussions with the City of Cambridge, we understand that an emergency generator or engine-driven fire pump in a commercial area with no residences nearby does not need to meet the City's noise

requirements. And if there is a nearby residence, the emergency equipment is exempt from the ordinance as long as it is tested during daytime hours.

Commonwealth of Massachusetts
The Commonwealth of Massachusetts has enacted regulations for the control of air pollution (310 CMR 7.10). To enforce these regulations, MassDEP has issued guidelines that encourage the use of reasonable noise control measures and limit the level of industrial noise in residential areas as follows: a) not to increase the residual ambient sound level by more than 10 dBA and b) not to produce a pure tone condition where the sound pressure level in one octave band exceeds the levels in the two adjacent octave bands by 3 dB or more.

MassDEP has also clarified the application of its noise guidelines in an update on its website (ref: http://www.mass.gov/dep/air/laws/noisepol.htm). The website information includes a section - "Where Are MassDEP's Noise Criteria Applied?" - that states:

> "The MassDEP noise pollution policy describes criteria that MassDEP uses to evaluate noise impacts at both the property line and the nearest occupied residence or other sensitive receptor. When noise is found to be a nuisance or a threat to health, MassDEP requires the source to mitigate its noise. Noise levels that exceed the criteria at the source's property line by themselves do not necessarily result in a violation or a condition of air pollution under MassDEP regulations (see 310 CMR 7.10 U). The agency also considers the effect of noise on the nearest occupied residence and/or building housing sensitive receptors:
>
> - In responding to complaints, MassDEP measures noise levels at the complainant's location and at other nearby locations that may be affected (e.g., residences and/or buildings with other sensitive receptors). If the noise level at a sensitive receptor's location is more than 10 dBA above ambient, MassDEP requires the noise source to mitigate its impact.
> - A new noise source will be required to mitigate its sound emissions if they are projected to cause the broadband sound level at a residence or building housing sensitive receptors to exceed ambient background by more than 10 dBA.
> - A new noise source that would be located in an area that is not likely to be developed for residential use in the future (e.g., due to abutting wetlands or similarly undevelopable areas), or in a commercial or industrial area with no sensitive receptors may not be required to mitigate its noise impact on those areas, even if projected to cause noise levels at the facility's property line to exceed ambient background by more than 10 dBA. However, a new noise source that would be located in an area in which housing or buildings containing other sensitive receptors could be developed in the future may be required to mitigate its noise impact in these areas.
>
> This policy has been designed to protect affected residents and other sensitive occupants of nearby property, but not necessarily uninhabited areas in and around the source's property. Sources of noise may need to implement mitigation if residences or buildings occupied by sensitive receptors are developed where they may be affected by the source's noise."

The residual ambient sound level may be defined for the purpose of the MassDEP guidelines as the L90 level over the time period of concern or by other means acceptable to MassDEP. In order for a noise source to comply with the 10 dBA criterion, its sound level should not be more than 9 dBA above the ambient sound level.

SURVEY RESULTS

We obtained measurements and observations on all 57 emergency generators and fire pumps that serve

the MIT campus. Table 1 summarizes the overall A-weighted sound levels that we measured during daytime and nighttime ambient conditions and during daytime equipment operating conditions. We identified the nearest non-MIT and MIT residential units, which included apartments, dorms, and hotel units, nearest each generator or pump and determined the equipment sound levels at the noise-sensitive locations based on our direct measurements. When the receptor location was relatively distant from the equipment, we calculated its operating sound level based on the direct measurements around the unit and on factors that account for distance attenuation and possible shielding by intervening buildings.

Nearest Community Receptors
Our measurements and observations indicated that the following two diesel generators produced elevated sound levels that exceed the MassDEP broadband sound guideline (10 dBA increase above ambient) at noise sensitive locations accessible by the general public:

- DG-W98 (in enclosure) – 5 dBA in excess of the allowable increase at the nearby hotel at night.
- DG-48 (inside building) – 2 dBA in excess of the allowable increase at the nearby park gazebo (although it is not a residence, may not be considered a noise sensitive location, or may not be in use at night, we have included it as it could host nighttime music performances).

In addition, DG-W98 produced tonal sound that was noticeable to the field team outside of a nearby hotel.

Nearest on Campus Residences
We also identified the following five generators that produced elevated sound levels at adjacent MIT residential facilities. Of the five generators, three are within building equipment rooms and two are within outdoor enclosures. Should MIT wish to address these units, the following lists the generators and suggested minimum noise reduction goals:

- DG-E14 (inside building) – 4 dBA
- DG-NW30 (inside building) – 6 dBA
- DG-W1 (in enclosure) – 11 dBA
- DG-W70 (in enclosure) – 10 dBA
- DG-W91-0 (inside building) – 6 dBA

Plus, NGG-W84 (inside building) produced tonal sound that was noticeable to the field team outside a nearby MIT residential facility.

Our survey measurements and observations indicate that the engine sounds propagating from the ventilation air intake and discharge openings are the primary contributors to the elevated broadband sound levels for most of the above units and that engine exhaust sound produces a tonal condition for two of the units. The following course of action aims to reduce the generator sound at noise sensitive locations in the community and on campus:

1. MIT continue to perform the regular operational testing of all of the generators and engine-driven fire pumps during weekday daytime hours.

2. Install treatments on the ventilation air inlet and outlet paths of each of the above units (except DG-W98 and NGG-W84) to mitigate broadband sound. The treatment options include an acoustically-lined plenum [e.g., 4-in. thick sound-absorptive metal panel or 4-in. thick glass fiber (duct liner) and protected by a minimum 25% open perforated or metal mesh cover], a 3-ft. long standard parallel baffle muffler, and a local barrier. The local barrier near an opening would be sized to block the

line-of-sight from the opening to the residences.

3. Install secondary engine exhaust muffler in series with the current muffler on each unit to mitigate the tonal sound.

4. Acentech and the MIT team review the generator installations and develop detailed designs and specifications of the treatments for each of the units.

5. Measure and reassess the sound of the above generators following their treatment.

CONCLUSIONS

Based on our measurements and analysis, we believe that the two emergency generators produce sounds at non-MIT noise sensitive receptors that do not comply with the MassDEP Noise Guidelines. In addition, we identified six additional generators that produce sounds at MIT residential receptors that are inconsistent with the guidelines. Installing effective retrofit treatments on these generators should bring the entire fleet into agreement with the guidelines for both broadband and tonal sound at noise-sensitive receptor locations.

****

I trust that this information serves your needs at this time. Please contact me (617-499-8018 or jbarnes@acentech.com) with any questions or comments about this letter or our study.

Sincerely yours,

James D. Barnes, P.E.
Acentech Incorporated

Table 1

xc: M. Thornton/Vanderweil
S. Dwyer/Vanderweil

J:\ 624469-MIT-EmerGens&Pumps011215-100515.doc

Table 1.
Summary of MIT Emergency Generators and Engine-Driven Fire Pumps Tested between 8/5/2014 and 11/13/2014 and their Measured Sound Levels.

			Sound Level (dBA)				
Building Location	DEP Emission Unit #	MIT PM ID	Measured Ambient Day	Measured Ambient Night	Measured Operating*	*>10 dBA increase?*	*Tonal?*
8	DG-8	734744	67	62	<67		
16	DG-16-906-A	718454	55	60	58		
18	NGG-18	732194	64	62	<68		
32	DG-32	733222	66	59	63		
42	DG-42-6	NA	74	67	72		
46	DG-46-01	801225	57	57	<60		
46	DG-46-02	801227	57	59	<60		
48	DG-48	730191	67	59	71	yes	
62/64	DG-62/64	731605	63	62	63		
68	DG-68-701A	716229	65	61	63		
76	DG-76	802358	61	59	62		
E14	DG-E14	801757	62	52	66	yes	
E15	DG-E15	708451	58	59	59		
E18	NGG-E18	717195	55	60	58		
E19	DG-E19	700703	60	56	<65		
E2	DG-E2	718474	56	52	61		
E25	DG-E25	734731	54	52	<56		
E25	DG-E25-02	802528	54	52	<56		
E38	DFP-E38	802288	57	57	66		
E40	DG-E40	707012	55	56	63		
E51	DG-E51	707128	61	55	<57		
E53	NGG-E53	700058	58	56	59		
E55	NGG-E55	704498	59	56	<58		
E62	DG-E62	802137	61	55	61		
N52	DG-N52-090	703200	59	59	<62		
N57	DFP-N57	802289	57	56	61		
N9A	DG-N9A	701337	65	57	<60		
N9B	DG-N9B	730188	65	57	<60		
NW10	DG-NW10	711440	62	60	<70		
NW14	DG-NW-15A	NA	60	60	<63		
NW14	DG-NW-15B	NA	60	60	<63		
NW15	DG-NW15-100	710318	63	56	<64		
NW30	DG-NW30	731726	53	50	66	yes	
NW35	DG-NW35	801306	57	56	64		
NW61	NGG-NW61	703588	63	55	<60		
NW86	DG-NW86	733111	58	56	63		
W1	DG-W1	804129	56	57	77	yes	
W16	NGG-W16	703034	54	49	<56		
W20	DG-W20	710747	56	56	63		
W31	DG-W31	703591	63	61	63		
W34	DG-W34-M40	704932	65	57	<62		
W4	NGG-W4	704494	57	53	56		
W4	DG-W4	704495	57	53	63		
W51	NGG-W51	704492	52	47	<57		
W51	DFP-W51	732372	52	47	<57		
W53	NGG-W53	734949	52	53	59		
W7	DG-W7	704493	52	49	57		
W70	DG-W70	804231	53	50	70	yes	
W71	DG-W71	707165	59	61	64		
W79	DG1-W79	733483	54	52	<61		
W79	DG2-W79	733484	54	52	<61		
W84	NGG-W84	704451	57	52	62		yes
W85	NGG-W85	704476	52	54	52		
W89	DG-W89	734535	53	54	56		
W91	DG-W91-0	730189	61	53	69	yes	
W92	DG-W92	730891	55	53	61		
W98	DG-W98	801300	60	54	69	yes	yes

*Reported levels based on direct measurements and calculations to the nearest noise-sensitive receptors.