Commonwealth of Massachusetts
Executive Office of Energy & Environmental Affairs

Department of Environmental Protection

Western Regional Office • 436 Dwight Street, Springfield MA 01103 • 413-784-1100

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September 14, 2012

Ms. Katherine P. Craven, Executive Director

University of Mass. Building Authority

225 Franklin St., 12th Floor

Boston, MA 02110

Re: PVAPCD–Amherst

Regulation 310 CMR 7.02(5)(a)

Appl. #1-B-08-015; Trans. # W210315

Univ. of Mass. – Amherst Campus

Central Heating Plant

Conditional Approval (amended)

Dear Ms. Craven:

The Massachusetts Department of Environmental Protection, Western Regional Office ("MassDEP") received on February 12, 2008 a Plan Application from the University of Massachusetts Building Authority, 225 Franklin Street, 12th Floor, Boston, Massachusetts ("UMBA") for the replacement of the existing steam plant and the installation and operation of a new Central Heating Plant ("CHP") at the University of Massachusetts, Amherst, Massachusetts ("UMass–Amherst"). The Plan Application was submitted in response to a Notice of Noncompliance issued by MassDEP which required UMBA to submit a new plan application reflecting the actual equipment installed since it differed from what was originally proposed by UMBA. The plans bear the seal and signature of Stephen Couture, Massachusetts Registered Professional Engineer No. 31057

On April 28, 2008, MassDEP was informed that UMBA and UMass–Amherst will commit to burning ultra-low sulfur distillate ("ULSD") oil containing less than 0.0015% sulfur by weight in the new CHP. A revised Plan Application reflecting the use of ULSD oil was received by MassDEP on June 26, 2008.

On December 8, 2009, MassDEP received a request from UMBA to change the volumetric ammonia emission limits (parts per million, by volume, dry, or "ppmvd") for the new combustion turbine & duct burner, and the three new boilers at UMass–Amherst under certain defined operating conditions. There will be no change in the yearly potential emissions (tons per year; tpy) or the short term mass emission limits (pounds per hour; lb/hr). UMBA also requested that the operating conditions of start-up/shutdown/fuel switching be addressed regarding limits on emissions allowed and on the amount of time allowed for these activities. These modified ammonia emission limits were included in the original CHP Conditional Approval dated 12/31/2009.

On January 19, 2011, MassDEP received a request from UMBA/UMass–Amherst to clarify the monitoring data capture requirements in Tables 10c, 10d, and 10e. This change is reflected in the 1/19/2011 Amendment.

On August 30, 2011, MassDEP received a request from UMBA/UMass–Amherst to change the NOx and NH_3 emission limits during operation when the ambient temperature is ≤ 0°F, and to change the smoke/opacity limit of the CTG during startup to the MassDEP regulatory standard specified in 310 CMR 7.06(1) (a) and (b).

On April 4, 2012, UMass–Amherst met with MassDEP to address issues related to the permitted boiler VOC emission factors and boiler opacity at low loads. Regarding the boiler VOC emission factors, this Conditional Approval Amendment incorporates changes proposed by UMass to the approved emission limits, since the emission factors were erroneously stated in the initial application stages, as documented in a Memorandum to MassDEP dated May 16, 2012 by the consulting firm Woodard & Curran of Portland, Maine ("Woodard & Curran"). Changing the boiler VOC emission factors results in a decrease in potential VOC emissions from the boilers from 8.1 tons per year to 7.3 tons per year, under the operating and fuel use conditions detailed in ***III. Source Emissions*** and **Table 1** of this Conditional Approval Amendment.

Regarding the boiler opacity issues, this Conditional Approval Amendment incorporates the adoption of a Boiler Opacity Standard Operating Procedure (SOP) documented in a letter dated August 16, 2012 from Woodard & Curran and approved by MassDEP on August 24, 2012 that summarizes the history of boiler opacity events and documents how UMass–Amherst will respond to opacity excursions reported by the continuous opacity monitor that frequently do not correspond to combustion related parameters or visible emissions out the stacks. See Section ***V. Best Available Control Technology (BACT) Analysis***: ***Conclusions***: ***Boiler Opacity (non-combustion related) Compliance Issues*** for more detail.

These changes, along with and the deletion of requirements that have been fulfilled, are being incorporated into the CHP Conditional Approval with the issuance of this Conditional Approval Amendment.

Please be advised that this Conditional Approval Amendment (9/14/2012) replaces in-full all prior versions of this approval.

In accordance with the Massachusetts Environmental Policy Act, UMBA submitted an Expanded Environmental Notification Form for the new plant to the Executive Office of Environmental Affairs on August 15, 2002 (EOEA No. 12864). The Secretary of Environmental Affairs subsequently certified the Expanded Environmental Notification Form on September 23, 2002 without requiring an Environmental Impact Report.

I. Overview

The CHP will be located in an area currently used for athletic fields just west of the Mullins Center on Campus Center Way. The existing steam plant, consisting of seven boilers fired with coal, natural gas, and/or fuel oil, as well as the coal handling and storage facilities located elsewhere on campus, will be decommissioned upon startup of the CHP.

The pollutants resulting from the operation of this new CHP will come from the burning of natural gas and oil. They will include particulate matter ("PM"), particulate matter with a mean diameter of less than 10 microns ("PM_{10}"), particulate matter with a mean diameter of less than 2.5 microns ("$PM_{2.5}$"), sulfur dioxide ("SO_2"), sulfuric acid mist ("H_2SO_4 mist"), nitrogen dioxide ("NO_2"), nitrogen oxides (sum of nitrogen oxide ["NO"] plus NO_2; hereinafter "NOx"), carbon monoxide ("CO"), ozone ("O_3"), and lead ("Pb"). An additional pollutant, ammonia ("NH_3"), is emitted from the operation of the SCR control equipment.

The installation and operation of the new CHP will be a "major modification" of an existing major source of air pollution since there will be a "significant" increase in emissions of PM_{10}. Hence, the CHP is subject to the requirements of the United States Environmental Protection Agency ("EPA") Prevention of Significant Deterioration ("PSD") regulations for PM_{10} as set forth in 40 CFR Part 52.21. Because the CHP is not classified as a major modification of either NO_x or VOC, the project is not subject to the requirements of Non-Attainment New Source Review ("NNSR") as set forth in 310 CMR 7.00, Appendix A.

II. Project Description

CTG, HRSG, Duct Burner

The proposed combustion turbine/generator ("CTG") will be a Solar Mars 100 series machine with a nominal rating of 10 megawatts ("MW") and a heat input rating of approximately 137.9 million British Thermal Units per hour ("MMBtu/hr") while burning natural gas. It is also capable of burning ULSD oil containing ≤0.0015% sulfur by weight. The CTG exhaust will be discharged to a heat recovery steam generator ("HRSG") with a rated steam output of 100,000 pounds per hour ("lb/hr") equipped with a duct burner with a maximum rating of 91.8 MMBtu/hr that is fired exclusively with natural gas. More detailed specifications and performance data for the proposed CTG/HRSG are provided in Table A in the Appendix.

The CTG will utilize a dry low-NO_x ("DLN") combustor in conjunction with a selective catalytic reduction ("SCR") add-on control system to minimize the emissions of NOx. The CTG will also be equipped with an oxidation catalyst system to control CO emissions. The design of the combustion installations, implementation of good operating practices, and the use of natural gas or ULSD oil will serve to control emissions of PM/PM_{10}/$PM_{2.5}$, SO_2, H_2SO_4 mist, and VOC.

Boilers

Boiler #200 is a Rentech high pressure boiler ("Boiler #200-HP") rated at 173.4 MMBtu/hr firing ULSD oil and 179.7 MMBtu/hr firing natural gas. Boilers #300 and #400 are Rentech low pressure boilers ("Boiler #300-LP" and "Boiler #400-LP") rated at 156.1 MMBtu/hr firing ULSD oil and 162.1 MMBtu/hr firing natural gas. All are rated at approximately 125,000 lb/hr steam flow. These boiler ratings are based on at an ambient temperature of 80°F. More detailed specifications and performance data for the proposed boilers are listed in Table B in the Appendix.

Each boiler will utilize low-NO_x burners ("LNB") in combination with an SCR NOx control system. To control CO emissions, each of the boilers will be equipped with an oxidation catalyst. The design of the combustion installations, implementation of good operating practices, and the use of natural gas or ULSD oil will serve to control emissions of $PM/PM_{10}/PM_{2.5}$, SO_2, H_2SO_4 mist, and VOC.

The new CHP will also include an existing low pressure steam turbine/generator nominally rated at 4 MW that will be relocated from the old heating plant, and a new high pressure steam turbine/generator nominally rated at 2 MW.

CTG/HRSG & Boiler Stack Configuration

The CTG/HRSG is vented through a 125 foot high, 72-inch diameter stack. The boilers are vented through three identical 125 foot high, 54-inch diameter stacks. The CTG / HRSG stack and the three boiler stacks are grouped in a cluster and supported by a common superstructure, surrounded on the north and south by two porous aesthetic screens of which more than 50% of the surface area is open. The screens are constructed of 4-foot by 8-foot stainless steel panels.

Emergency Generator

The proposed reciprocating engine emergency generator will supply electrical power in the event of a power outage at the CHP. It is rated at 1,357 horsepower, at a maximum heat input rate of 9.13 MMBtu/hr and at a maximum power output of 900 kilowatts ("kW"), firing either natural gas or ULSD oil. It will operate ≤ 300 hr/yr.

Petroleum & Chemical Storage Tanks

The CHP will include two 234,810 gallon storage tanks for ULSD oil and two 4,300 gallon storage tanks containing 19.5% aqueous NH_3. The NH_3 tanks will be single wall, steel, horizontal fixed-roof storage tanks located inside a single impervious concrete secondary containment dike. These and the other new storage tanks needed for various chemicals required for air pollution control, boiler feedwater treatment, and process wastewater treatment are summarized in Table C in the Appendix.

III. Source Emissions

The potential emissions from the CTG and HRSG are based on the CTG burning natural gas with 90 days ULSD oil backup, and the HRSG duct burner operating on natural gas exclusively. Potential emissions for the boilers are based on Boiler #200-HP firing ULSD oil October 1st through April 30th and firing natural gas the remainder of the year, one LP boiler firing ULSD oil year-round, and one LP boiler operating ½ on natural gas and ½ on USLD oil for the entire year. See Table 1 below:

Table 1

Proposed CHP Potential Emissions

Pollutant	CTG, HRSG, Duct Burner (tons per year)	Boilers (tons per year)	Emergency Engine/Generator (tons per year)	Total (tons per year)
$PM/PM_{10}/PM_{2.5}$	31.4	57.9	0.1	89.4
SO_2	1.9	3.1	0.07	5.0
NO_x	13.7	28.9	1.94	44.5
CO	12.1	53.4	1.04	66.6
VOC	2.2	7.3	0.3	9.8
H_2SO_4 mist	0.3	0.5	–	0.8
NH_3	3.0	2.0	0.0	5.0

The ULSD oil allotment for the boilers for May 1st through September 30th may be used on any of the boilers, but the most likely operating scenario will have the LP boilers firing ULSD oil during May 1st through September 30th. See Table 2 below:

Table 2

CHP Oil Use Allotment

Emission Unit	Operating load / hours	Fuel	ULSD Oil Use Restrictions
CTG	100% load for 6600 hr	natural gas	2,229,611 gallons
CTG	100% load for 2160 hr (90 days equivalent)	ULSD oil	
duct burner	100% load for 8760 hr	natural gas	
Oct. 1st-April 30th			15,508,252 gallons
Boiler #200-HP	100% load for 5088 hr *	ULSD oil	

Boiler #300-LP or #400-LP	100% load for 5088 hr *	ULSD oil	
Boiler #300-LP or #400-LP	50% load for 5088 hr (2544 hr equivalent**)	natural gas or ULSD oil	
May 1st-Sept. 30th			6,357,830 gallons
Boiler #200-HP	100% load for 3672 hr	natural gas	
Boiler #300-LP or #400-LP	100% load for 3672 hr	ULSD oil	
Boiler #300-LP or #400-LP	50% load for 3672 hr (1836 hr equivalent***)	natural gas or ULSD oil	

*5112 hr/yr for leap year **2568 hr equivalent for leap year ***1860 hr equivalent for leap year

More detailed emission/performance data for the CTG/duct burner, HP and LP boilers, and emergency engine/generator are listed in Tables D, E-1, E-2, and F in the Appendix.

IV. Regulatory Applicability

The applicable regulations include:

- ***National Ambient Air Quality Standards ("NAAQS")***
- ***MassDEP 7.02 Plan Approval Requirements***
- ***MassDEP Industry Performance Standards ("IPS")***
- ***MassDEP Noise Requirements***
- ***Non-Attainment New Source Review ("NNSR")***
- ***Prevention of Significant Deterioration Review ("PSD")***
- ***New Source Performance Standards ("NSPS")***
- **National Emission Standards for Hazardous Air Pollutants ("NESHAPS")**
- ***Accidental Release Program***

National Ambient Air Quality Standards ("NAAQS")

The EPA promulgated NAAQS for seven air contaminants known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, O_3, and Pb.

The purpose of Federal and State air quality regulations is to ensure that ambient air quality complies with the NAAQS. Accordingly, EPA has classified all regions of the country as "attainment", "nonattainment," or "unclassifiable" with respect to the ambient air quality standards. The Towns of Amherst and Hadley are currently designated as attainment or as unclassifiable for PM_{10}, $PM_{2.5}$, SO_2, NO_2, CO, and Pb. The region is also currently classified as moderate nonattainment for O_3.

To identify those new sources with the potential to violate or contribute to a violation of the NAAQS, the EPA and MassDEP has adopted significant impact levels ("SILs") for PM_{10}, $PM_{2.5}$, NO_2, SO_2, and CO. If the modeled impacts of a new source are found to be below the SILs, no further analysis is required to assess compliance with ambient air quality standards. If the impacts are found to exceed the SILs, a more detailed dispersion modeling analysis is required which must consider the impacts associated with not only the new source, but also existing sources in the region. Additional information and discussion on this is provided in the section entitled Ambient Air Quality Impact Analysis.

MassDEP 7.02 Plan Approval Regulations

The application filed in accordance with MassDEP plan approval regulations (310 CMR 7.02) must demonstrate that the combustion equipment will incorporate air pollution control technologies representative of BACT and that the resulting emissions will not cause or contribute to a violation of applicable ambient air quality standards and PSD allowable increments.

MassDEP Industry Performance Standards ("IPS")

For the emergency engine, Regulation 310 CMR 7.26(42) Emergency Engines and Turbines applies. The emission rate of NOx+HC (g/KW-hr) is 6.4 and is in compliance with 40 CFR Part 89. The CO and PM emission rates (g/KW-hr) are 3.5 and 0.2, respectively and are consistent with 40 CFR 89.

MassDEP Noise Regulations

MassDEP promulgated regulations governing noise from new and existing equipment under Regulation 310 CMR 7.10 and Policy 90-001. According to MassDEP Policy, new equipment is not allowed to increase ambient sound levels by more than 10 decibels above the lowest measured community sound level at both the property boundaries and the nearest inhabited structures. In addition, new equipment is not permitted to emit tonal noise, defined as occurring when any octave band center frequency sound pressure level exceeds the two adjacent center frequency sound pressure levels by 3 decibels or more.

Non-Attainment New Source Review ("NNSR")

In accordance with Regulation 310 CMR 7.00 Appendix A, the owner or operator of a major source located in a nonattainment area must determine if a modification of the source results in a "significant" increase in emissions. The owner or operator can take credit for contemporaneous emission reductions in determining whether an emissions increase is "significant".

The existing steam plant is classified as a major stationary source of NO_x and is located in a moderate nonattainment area for O_3. A modification to an existing major source is subject to NNSR if the net increase in the potential NO_x or VOC emissions is ≥ 25 tpy. The net change in potential emissions is based upon the future potential emissions from the proposed sources minus the actual emissions from existing sources being retired as part of the action and contemporaneous emission changes occurring over the five years prior to operation of the new source.

Table 3 details the potential emissions from the new CTG/HRSG and the boilers and the net change in the potential NO_x and VOC emissions associated with the new CHP. As shown, the net increase in potential NO_x and VOC emissions would both be less than 25 tpy. The new CHP is therefore not subject to the requirements of NNSR.

Table 3

NNSR Applicability Determination

Pollutant	Proposed CHP Potential Emissions (tpy) (1)	Existing Plant Actual Emissions (tpy) (2)	Net Change in Emissions (tpy)	Significant Emission Rates (tpy) (3)
NOx	44.5	174.31	-129.8	25

VOC	9.8	22.96	-13.16	25

(1) Based on potential emissions from the CTG and three boilers as described above operating at maximum load and the duct burner operating at maximum load firing natural gas in any 12-month rolling period.

(2) Based on actual emissions from the existing boilers averaged over calendar years 2001 and 2002.

(3) Significant emission rates triggering NNSR.

Prevention of Significant Deterioration Review ("PSD")

The existing steam plant is classified as a major source and is located in attainment or unclassified areas for PM_{10}, SO_2, NO_2, and CO. A modification to an existing major source is subject to PSD review if the net change in the potential emissions of any regulated pollutant is "significant". The net change in potential emissions is based upon the future potential emissions from the proposed sources minus the actual emissions from existing sources being retired as part of the action and contemporaneous emission changes occurring over the five years prior to operation of the new source. The actual emissions from the existing boilers are based upon the average emissions over calendar years 2001 and 2002.

Table 4 documents the net change in PM_{10}, SO_2, NO_x, CO, and VOC emissions associated with the CHP. As shown, the CHP will be considered a major modification for PM_{10} and thus is subject to PSD review for that pollutant.

Table 4

Net Change in Emissions

Pollutant	Proposed CHP Potential Emissions (tons per year)(1)	Existing Plant Actual Emissions (tons per year)(2)	Net Change in Emissions (tons per year)	Significant Increase (tons per year)
PM_{10}	89.35	4.14	+85.21	15 (3)
SO_2	5.0	389	-384	40 (3)
NO_x	44.5	174	-130	40 (3)/ 25 (4)
CO	66.5	44	+22	100 (3)

VOC	9.8	23	-13	25 (4)

(1) Based on the CTG & boilers operating at max. load firing oil, the duct burner at max. load firing ng, and the emergency engine operating at max. load for 300 hr/yr.

(2) Based on actual emissions from the existing boilers averaged over calendar years 2001 and 2002.

(3) Significant emission rates triggering PSD review

(4) Significant emission rates triggering non-attainment review

New Source Performance Standards ("NSPS")

The EPA has promulgated performance standards for new stationary sources pursuant to Section 111 (b) of the Clean Air Act (40 CFR Part 60). These NSPS establish emission limitations and monitoring, recordkeeping, and reporting requirements for certain categories of industrial and commercial facilities.

- ***40 CFR 60 Subpart KKKK – Stationary Combustion Turbines***

  Because the project commenced construction, modification, or reconstruction after February 18, 2005, per §60.4305 the turbine and the duct burner are subject to Subpart KKKK, which limits NOx emissions and sulfur content in fuel. The CTG/duct burner will meet the NOx limit through the use of dry low NOx combustion and SCR add-on control equipment, and will meet the sulfur content limit through the use of clean fuels. The duct burner will burn natural gas exclusively.

- ***40 CFR 60 Subpart Db – Large Industrial Boilers***

  Because the new boilers each have a maximum rated capacity of more than 100 MMBtu/hr, they will be subject to the particulate and NOx standards under 40 CFR Subpart Db. These NSPS limit PM emissions from affected units firing oil alone or in combination with other fuels to 0.1 pounds per million Btu ("lb/MMBtu") and NOx emissions from affected units firing natural gas or distillate oil to 0.2 lb/MMBtu. Because the boilers will burn ULSD oil, they will not be subject to the SO_2 standards under subpart Db. Compliance with BACT will ensure that the particulate and NOx emissions from the new boilers will be well below the applicable NSPS.

National Emissions Standards for Hazardous Air Pollutants ("NESHAP")

Pursuant to Section 112(b) of the Clean Air Act, the EPA has promulgated the NESHAP under 40 CFR Parts 61 and 63.

The existing coal-fired boilers at the campus constitute a major source of hazardous air pollutants ("HAP") because they have the potential to emit more than 10 tons of hydrogen chloride annually. Therefore, the CTG at the new CHP is potentially subject to NESHAP for stationary combustion turbines (40 CFR 63 Subpart YYYY), and the HRSG/duct burner and the boilers at the new CHP are potentially subject to NESHAP for industrial, commercial, and institutional boilers (Subpart DDDDD). However, since the existing coal-fired boilers will be permanently shutdown concurrently with the startup of the new CHP, Subpart YYYY for the CTG and Subpart DDDDD for the HRSG/duct burner and boilers will not be applicable.

Accidental Release Program

Because of the SCR control equipment being used on the CTG and boilers, it will be necessary to store aqueous NH_3 on-site. The proposed CHP will use aqueous NH_3 at concentrations of <19.5%. Thus the NH_3 storage facilities will not be subject to the EPA's Accidental Release Program under 40 CFR Part 68. However, the provisions of Section 112(r) of the Clean Air Act include a "general duty clause" that requires such facilities to be designed and operated in a manner that prevents the release of NH_3 and that minimizes the consequences of an accidental release.

The aqueous NH_3 will be stored on-site in two 4,300 gallon, single-wall steel, vertical fixed-roof storage tanks located inside a single impervious concrete secondary containment dike which will have sufficient volume to contain 110 percent of the liquid from one of the tanks plus rain water from a 25-year storm. A concrete dike also serves as a physical barrier that will prevent accidental contact of vehicles or other equipment with the storage tanks.

In the highly unlikely event of an aqueous NH_3 release, the area within the dike will be equipped with evaporative controls (ball-like baffles) to reduce the potentially exposed area to less than 10 percent of the total available surface area.

NH_3 transfer from the delivery truck to the storage tanks will be conducted within a fully contained unloading area. Interconnecting piping will be designed to enable spills to be directly routed to the tank containment areas. A hose from off the top of the tank will be connected back to the truck to contain fumes displaced by filling operations.

- ***Off-Site Consequences Analysis***

  To assess the potential for off-site impacts resulting from a hypothetical worst-case release scenario (i.e., a rupture of the tank wall that contains the aqueous NH_3), an off-site consequences analysis was performed using the protocols established in the regulations implementing the EPA's Risk Management Program (40 CFR Part 68).

  The potential worst-case release impact distance was calculated using the recommended 112(r) RMP protocols presented by EPA in its' guidance documents. The potential worst-case impact distance was predicted using the Areal Locations of Hazardous Atmospheres (ALOHA) Model.

  The ALOHA model results predict that the ground-level concentrations of neutrally buoyant aqueous NH_3 vapors beyond 90 feet will be 144 ppm, below the recently revised ERPG-2 concentration of 150 ppm. Therefore, the worst-case accidental release scenario (5,000 gallons consisting of 19.5% aqueous NH_3 solution in an impervious, diked area with evaporative controls) will not result in an excursion of the ERPG-2 guideline of 150 ppm at the operational boundary of the plant.

V. Best Available Control Technology (BACT) Analysis

A top-down BACT analysis was conducted, consisting of the evaluation of options and the selection of options for the following BACT components:

- **Combustion Turbine Technology**
- **Combustion Controls – CTG/HRSG & Boilers**
- **Add-on Controls – CTG/HRSG & Boilers**
- **Natural Gas Availability**

- **Distillate Oil Sulfur Content**
- **Conclusions**

Combustion Turbine Technology

In the November 2002 Plan Application submitted to MassDEP by the UMBA (with additional revisions/updates submitted between August and December, 2003), UMBA evaluated three commercially available CTGs for suitability in the proposed new CHP at UMass–Amherst. This analysis concluded that the Solar Mars 100 was best from an emission, reliability, and support perspective, and represented BACT.

Combustion Controls for CO / PM_{10} / VOC / SO_2 Control – CTG/HRSG & Boilers

CO, PM/PM_{10}/$PM_{2.5}$, and VOC are all products of incomplete combustion. These emissions can be minimized by the application of good combustion practices and the use of very low ash fuel. Both natural gas and ULSD oil are inherently very low in ash. Accordingly, UMass–Amherst proposes to use good combustion practices and the use of very low ash fuels on both the CTG/HRSG and boilers for the control of CO, PM/PM_{10}/$PM_{2.5}$ and VOC.

Emissions of SO_2 are controlled by utilizing fuels that are low in sulfur. Both natural gas and ULSD fuels are inherently extremely low in sulfur content, and are proposed as BACT.

Combustion Controls for NOx – CTG/HRSG

Water or Steam Injection

Water and steam are diluents that lower flame temperature to reduce thermal NO_x formation. Although water or steam injection reduces NO_x emissions to levels equivalent to that achieved with DLN combustors when firing natural gas, NO_x emissions are not significantly reduced when firing distillate oil. On the other hand, water or steam injection increases CO emissions appreciably due to the lower temperatures in the burnout zone. Since the CTG will burn oil for up to 90 days a year or more, water or steam injection was not given further consideration in the BACT analysis in deference to dry low-NOx control schemes.

Dry Low-NO_x Combustor

DLN combustors pre-mix the fuel and compressed air to prevent local zones of high temperatures that promote thermal NO_x formation. Solar offers a DLN combustor, called $SoLoNO_x$, capable of reducing NO_x emissions, for a dual-fuel firing configuration, to 38 ppmvd when firing natural gas and 96 ppmvd when firing distillate oil, both @15% O_2. Accordingly, UMass–Amherst proposes the use of SoLoNOx with the Solar Mars 100 CTG as BACT.

<u>Combustion Controls for NOx – Boilers</u>

To control NO_x emissions from the dual-fuel boilers, one can use LNB that use flame geometry control and fuel/air mixing to reduce the formation of thermal NO_x, either alone or in combination with flue gas recirculation ("FGR").

Burners have been recently developed with sophisticated control systems and FGR to result in very low NO_x emissions (~ 9 ppmvd). These configurations are effective while firing natural gas but not oil. Since the proposed boilers will burn mainly distillate oil, UMass–Amherst accordingly proposes to use LNB and FGR as combustion controls for NO_x on the boilers, with SCR add-on control technology for final NO_x reduction.

<u>Add-on Controls for NOx/CO – CTG/HRSG</u>

SCR

SCR is the most effective add-on control technology for reducing NO_x emissions from combustion turbines. The technology uses NH_3 to reduce NO_x to nitrogen gas and water in the presence of a catalyst. An SCR system typically reduces NO_x emissions by 90%. Accordingly, UMass–Amherst proposes to use SCR for control of NO_x emissions.

Oxidation catalysts

Oxidation catalysts are the only available add-on controls for the reduction of CO from CTGs. Accordingly, UMass–Amherst proposes to use an oxidation catalyst and good combustion practices for the control of CO from the CTG.

Add-on Controls for NOx/CO – Boilers

SCR

SCR represents the most stringent level of add-on NO_x control available for boilers. Accordingly, UMass–Amherst proposes to use LNB and FGR prior to SCR to control NO_x emissions from the boilers.

Oxidation catalysts

Oxidation catalysts are the only available add-on controls for the reduction of CO from boilers. Accordingly, UMass–Amherst will use an oxidation catalyst and good combustion practices for the control of CO from the boilers.

Natural Gas Availability

UMass–Amherst is located in a low population density area of Massachusetts that lacks large industrial complexes. Accordingly, natural gas supplies have not yet been extended to this area to support continuous availability.

To provide firm gas supplies to UMass–Amherst in the quantities necessary to operate the new CHP would require modifications/upgrades to both the local distribution company's (LDC) system and the major pipeline systems. The approximate $15 million cost of providing the upgrades by the pipeline operators and LDC would likely have to be borne, in part or in whole, by UMass–Amherst. The level of NO_x reduction associated with the upgrades would be approximately 31 tons, which would result in a cost of control in excess of $63,000 per ton of NO_x removed. Therefore, UMass–Amherst plans to negotiate its fuel contracts based on the present fuel availability and use distillate oil as the primary fuel. Natural gas will be burned to the extent allowable by the capability of the existing fuel distribution system.

Distillate Oil Sulfur Content

MassDEP issued on November 8, 2006 a Limited Plan Application Final Approval that determined that BACT for sulfur in fuel for the new CHP at UMass–Amherst was distillate oil with a sulfur content ≤ 0.05%.

On April 28, 2008, MassDEP received a copy of a letter from Patrick Daly, Director of the Physical Plant at UMass–Amherst addressed to David MacKenzie, Executive Director of the UMBA stating that UMass–Amherst will commit to burning oil containing less than 0.0015% sulfur by weight in the new CHP.

Conclusions

Gas Turbine/HRSG

UMass–Amherst proposes as BACT the use of the Mars Solar 100 CTG with SoLoNO$_x$ DLN technology, burning natural gas with up to 90 days of ULSD oil as backup.

SCR add-on controls will be designed to reduce NO$_x$ to 2.5 ppmvd firing natural gas and 6.0 ppmvd firing ULSD oil, both @15% O_2 (including the duct burner emissions), and to keep NH_3 slip to less than 2.0 ppmvd @ 15% O_2 with either fuel. An oxidation catalyst will control CO emissions to 5.0 ppmvd on natural gas and 5.0 ppmvd while burning ULSD oil, both @ 15% O_2.

Boilers

UMass–Amherst proposes as BACT the use of natural gas and ULSD oil in the boilers, which will employ LNB and FGR in combination with SCR to limit NO$_x$ emissions to 5.0 ppmvd during gas firing and 9.0 ppmvd during ULSD oil firing, both @ 3% O_2. NH_3 slip will be maintained below 2.0 ppmvd @ 3% O_2 with either fuel. An oxidation catalyst will control CO emissions to 20.0 ppmvd on natural gas and 25.0 ppmvd while burning ULSD oil, both @ 3% O_2.

CTG/HRSG and Boilers

UMass–Amherst proposes as BACT for PM and VOC the use of very low ash fuels (natural gas and ULSD) and to maintain good combustion practices.

UMass–Amherst proposes as BACT for SO_2 and H_2SO_4 the use of fuels inherently low in sulfur content (natural gas and ULSD), and by limiting the excess oxygen in the combustion process which minimizes the oxidation of SO_2 to H_2SO_4.

Ammonia Slip compliance issues

All 4 emission units utilize a "state of the art" selective catalytic reduction ("SCR") emission control system to minimize the emissions of nitrogen oxides into the ambient air. To achieve a low level of NOx emissions, ammonia is injected ahead of a catalyst on which a reaction with NOx takes place to lower stack NOx emissions. The amount of ammonia injected varies with the fuel firing rate which in turn varies to meet campus steam demand. Any unreacted ammonia continues to the stack where the concentration is determined by a differential NOx ammonia monitoring system before being emitted to the ambient air.

The combustion turbine and boilers are currently meeting the ammonia emission limits on a lb/hr basis, which is typically determined during compliance testing while the emission unit is operated at a constant 100% load.

However, during "TRANSIENT OPERATION" (defined as a 1-hour block period – and the subsequent hour – during which the difference between the highest and lowest firing rate for the combustion turbine, duct burner, or a boiler is 30 MMBtu/hr or greater) and "NORMAL OPERATION" (defined as a 1-hour block period during which the difference between the highest and lowest firing rate for the combustion turbine, duct burner, or a boiler is less than 30 MMBtu/hr), the SCR control system cannot consistently control the ammonia injection rate well enough to limit excess ammonia to less than 2.0 ppmvd on a 1-hour block period basis.

UMBA, UMass–Amherst, and the project vendors have expended considerable time and money to fine tune the SCR control system in the effort to meet the 2.0 ppmvd 1-hour ammonia emission limits, and have stated that they have reached the technical limits of what is possible during NORMAL OPERATION and TRANSIENT OPERATION. The MassDEP agrees with their assessment.

UMBA is therefore proposing that the allowable volumetric ammonia emission rate for the combustion turbines and the boilers be set as follows:

Proposed Volumetric Ammonia Emission Limits (1)

Emission Unit	Operating Mode	Natural Gas (ppmvd) (2)		ULSD (ppmvd) (2)	
		Existing Old limit	Proposed new limit	Existing Old Limit	Proposed new limit
Combustion Turbine & Duct Burner	NORMAL OPERATION	2.0	2.5	2.0	4.0
	TRANSIENT OPERATION	2.0	7.5	2.0	10.0
	ALL OTHER TIMES	2.0	2.5 (24-hour block average)	2.0	4.0 (24-hour block average)

Boiler #200	NORMAL OPERATION	2.0	2.5	2.0	4.0
	TRANSIENT OPERATION	2.0	7.5	2.0	10.0
	ALL OTHER TIMES	2.0	2.5 (24-hour block average)	2.0	4.0 (24-hour block average)
Boiler #300 Boiler #400	NORMAL OPERATION	2.0	2.5	2.0	4.0
	TRANSIENT OPERATION	2.0	7.5	2.0	10.0
	ALL OTHER TIMES	2.0	2.5 (24-hour block average)	2.0	4.0 (24-hour block average)

(1) "ppmvd" emission limits are corrected to 15% O_2 for CTG/Duct burner and 3% O_2 for the boilers.

(2) Based on a 1-hour block average, except where noted.

Definitions:

NORMAL OPERATION: A 1-hour block period during which the difference between the highest and lowest firing rate for the combustion turbine, duct burner, or a boiler is less than 30 MMBtu/hr.

TRANSIENT OPERATION: A 1-hour block period – and the subsequent hour – during which the difference between the highest and lowest firing rate for the combustion turbine, duct burner, or a boiler is 30 MMBtu/hr or greater.

ALL OTHER TIMES: A 24-hour block period, which may include both normal and transient operation.

Boiler Opacity (non-combustion related) Compliance Issues

Since startup, the UMass–Amherst boilers have experienced occasional opacity excursions (primarily during oil firing) as indicated by their Performance Specification 1 Continuous Opacity Monitoring System ("COMS"). The situation has been extensively studied by outside consultants and appears not to be combustion related, since carbon monoxide levels and visible emissions (as determined by EPA Method 9) remain at low levels during these events.

The recommended solution to this opacity issue was to remove most of the oxidation catalyst from the exhaust ducts of these units, since the monitored opacity seemed related to condensed deposits of sulfur compounds on the catalyst and in the ductwork. This solution was tested and appeared to ameliorate the problem, although the underlying mechanism remained unclear.

However, this removal of oxidation catalyst would result in higher carbon monoxide and volatile organic compound emissions which, in the opinion of MassDEP, were more important to keep at reduced levels than to alleviate an opacity issue that was likely not related to incomplete combustion but only indicated by in-stack opacity monitor readings that did not correspond to a visible emission.

Accordingly, MassDEP and UMass–Amherst agreed to establish a protocol (Standard Operating Procedure; hereinafter "SOP") that would be followed by control room operators as opacity monitor readings on the boilers approached the 10% limit established in this Conditional Approval Amendment. If the opacity was determined to be not combustion related, the SOP specified steps to be taken to monitor CO readings, flame conditions, and stack visible emissions in lieu of COMS data. If the opacity was combustion related, the SOP specified steps to alleviate the problem or to shut down the boiler.

References to this SOP appear in the footnotes to Table 9c and in the Monitoring section table of this Conditional Approval Amendment.

VI. Ambient Air Quality Impact Analysis

The dispersion modeling analysis was conducted in accordance with procedures documented in the air quality modeling protocol letter submitted to MassDEP and U.S. EPA, Region I, on November 20, 2007. The modeling approach was revised based on a technical memo dated January 22, 2008 concerning the configuration of stacks and screens, EPA comments provided in a meeting with EPA Region I on February 7, 2008, a technical memo dated February 28, 2008 to address stack merging, and follow-up discussions with EPA Region I.

Technical Approach

The objective of the air quality modeling analysis is to demonstrate that the predicted impacts of the proposed project will comply with the applicable NAAQS and PSD allowable increments for PM_{10}, $PM_{2.5}$, NO_2, CO and SO_2. Currently, the Towns of Hadley and Amherst are located in a region classified as attainment or unclassified for all of these pollutants.

Screening Modeling

To identify those new sources with the potential to violate or contribute to a violation of ambient air quality standards, the EPA has adopted significant impact levels (SILs) for pollutants subject to PSD requirements. If the impacts of a new source are found to be below the SILs, no further analysis is required to assess compliance with ambient air quality criteria. If the impacts are found to exceed the SILs, an interactive analysis is conducted which considers the impacts associated not only with the new source, but also with existing sources in the region.

The peak predictions for NO_2 and CO are below the SILs. However, the maximum predicted 24-hour average concentrations of PM_{10} and $PM_{2.5,}$ and the maximum 3-hour and 24-hour concentrations of SO_2, are greater than the corresponding SILS.

While the peak predicted SO_2 impacts from the CHP exceed the SIL of 5 micrograms per cubic meter ("$\mu g/m^3$") the concentrations plus background are less than 20 percent of the NAAQS, and the background have shown a steady downward trend. Single-source modeling results and background values indicate a high probability of compliance with the NAAQS for SO_2. Therefore, interactive modeling for SO_2 has not been performed.

Interactive Modeling

Interactive modeling analysis for PM_{10} and $PM_{2.5}$ was required to assess the impact of the CHP in combination with other major sources in the surrounding area. The major sources of PM_{10} located within 25 kilometers ("km") of the proposed site were identified. These sources include the following combustion installations: Smith College, Mount Tom, Solutia, MMWEC, Stony Brook Phase II and MASSPOWER. These sources were included in the assessment of compliance with the NAAQS for both PM_{10} and $PM_{2.5}$. Emission rates were adjusted upward to account for condensable particulates, since the allowable emission rates were set based only on the filterable fraction.

Of these sources, MMWEC, Stony Brook Phase II, and MASSPOWER are subject to the PSD regulations for PM_{10} and were included in the assessment of PSD allowable increment consumption.

To estimate the contribution of other sources in the region, ambient background concentrations of PM_{10} (24-hour average), $PM_{2.5}$ (24-hour average), and SO_2 (24-hour average) were conservatively estimated based on peak concentrations measured at representative MassDEP monitoring stations over the last three years.

Results of this "interactive" modeling analysis demonstrate compliance with the 24-hour average NAAQS and PSD allowable increment for PM_{10}, and with the 24-hour NAAQS for $PM_{2.5}$.

Air Toxics Analysis

To assess the potential health effects of air toxics emitted from the combustion installations, the projected ground-level concentrations of non-criteria pollutants were compared with the corresponding Threshold Effects Exposure Limits ("TELs") and Allowable Ambient Limits ("AALs") established by MassDEP in 1995. The projected 24-hour concentrations of non-criteria pollutants are well below the TELs and the predicted annual concentrations are below the AALs. Therefore, air toxic emissions from the new CHP will not pose a significant threat to public health.

Class I Area Analysis

The PSD regulations include the requirement to assess the plant's potential impacts on air quality and visibility in Class 1 Areas. The closest Class 1 Area is the Lye Brook Wilderness Area in Vermont, which is approximately 86 km north-northwest of the Amherst Campus. The major concern at Class I areas is the degradation of visibility resulting from long-range transport of pollution from distant major sources.

The project will result in a significant increase in PM_{10}, but the replacement of the existing plant with the CHP will result in a reduction in the actual emissions of all pollutants including PM_{10}, SO_2, and NO_x.

Particle scattering coefficient values for the components of atmospheric particulate indicate that reducing concentrations of sulfates and nitrates is more efficient in improving visibility than reducing concentrations of primary particulate. Therefore, the slight increase in particulate emissions from the project are likely to be more than offset by the reduction in SO_2 and NO_x emissions and the preferential scattering of light by sulfates and nitrates. The net result should be an improvement in visibility in the Lye Brook Wilderness Area.

Based upon these considerations, the UMBA requested assistance from the U.S. Forest Service ("USFS") in establishing the need to assess the impacts of the proposed project on air quality and visibility in the Lye Brook Wilderness Area. In the USFS's response of June 12, 2002, the agency determined that *"there will be no adverse impacts, and possibly a net benefit, to the Lye Brook Wilderness connected to the proposed modifications to the University of Massachusetts Central Heating Plant)".* Accordingly, the USFS stated that no air quality or visibility analysis would be required for the Lye Brook Wilderness Area.

Conclusion

The modeling analysis results are presented in Table 5 below:

Table 5

Modeling Results

Pollutant	Averaging Period	NAAQS (µg/m³)	PSD Increment (µg/m³)	PSD Significant Impact Levels (µg/m³)	Maximum Predicted Impact (µg/m³)
NO_2	Annual	100	25	1	0.214
SO_2	Annual 24-hour 3-hour	80 365 1,300	20 91 512	1 5 25	0.59 9.0 45.9
PM_{10}	24-hour	150	30	5	8.65
$PM_{2.5}$	Annual 24-hour	15 35	N/A N/A	1 5	0.57 8.65
CO	8-hour 1-hour	10,000 40,000	N/A N/A	500 2,000	11.3 50.9

For those pollutants modeled below the SILs, no further analysis was required. For those pollutants where the screening analysis showed impacts exceeding the SILs, interactive source modeling was conducted. This modeling, along with the Air Toxics Analysis and the Class 1 Area Analysis, indicates that the proposed CHP will not have an adverse impact on air quality and or public health or welfare in the area. Furthermore, the plant's impact will not exceed any PSD allowable increment, and thus will not cause or contribute to a significant deterioration of existing air quality.

After this modeling analysis was performed, UMass–Amherst committed to using ULSD oil containing 0.0015% sulfur by weight instead of the 0.05% sulfur by weight oil used in the modeling demonstration. Since the burning of ULSD oil produces fewer pollutants due to its lower sulfur and ash content than the 0.05% sulfur oil used in the analysis, the conclusions reached above regarding the absence of adverse impacts from the new CHP remain applicable.

VII. Noise Impact Analysis

The CHP is located in the western quadrant of the University of Massachusetts Amherst Campus. The Southwest Dormitories, located approximately 2,500 feet southeast of the site, are the nearest University dwellings to the proposed plant. The nearest off-site residences are located approximately 1,600 feet to the west along Stockbridge Road. Additional residences are found to the north along North Pleasant Street. The nearest off-site location that has the potential for commercial or residential development is located approximately 900 feet away at the east end of Stockbridge Street.

A noise impact assessment was conducted to demonstrate that the proposed CHP will comply with requirements under 310 CMR 7.10, MassDEP Policy 90-001, and BACT. The noise impact assessment was conducted in accordance with an approved protocol submitted to MassDEP on April 18, 2002 and comments received from MassDEP on the impact assessment in the original application.

The noise surveys were intended to acoustically characterize the environment near the site and within the community. Because the CHP will operate 24-hours per day, and because ambient levels are typically lowest during late evening to early morning hours, sound level measurements were collected throughout the early morning hours of both surveys.

Six noise monitoring locations were selected to provide adequate spatial representation of noise-sensitive receptors during the original survey, conducted from May 15 through May 16, 2002. Weather conditions during daytime measurements consisted of cloudy skies, calm winds and ambient temperatures of about 50 degrees Fahrenheit ("ºF"). Weather conditions during early morning measurements consisted of clear skies, calm winds and ambient temperatures of about 42ºF.

Based upon a review of the initial noise survey in the original application, MassDEP requested a second noise survey to be conducted during the winter season. MassDEP also requested that a seventh monitoring location be included in the winter survey to account for potential residential or commercial development at the easternmost end of Stockbridge Street. This second noise survey was conducted from January 29 through January 30, 2003. Weather conditions during daytime measurements consisted of cloudy skies, calm winds and ambient temperatures of about 30ºF. During early morning measurements, skies were clear, winds were calm and ambient temperatures were about 13ºF. Table 6 below summarizes the noise monitoring locations.

Table 6

Noise Monitoring Locations

Position	Description
Location 1	Northern Residences along North Pleasant Street
Location 2	Site Property Boundary
Location 3	University Baseball Field/Mullins Center
Location 4	University Southwest Dormitories (Southeast of Site)
Location 5	Nearest Western Residences along Stockbridge Street
Location 6	Additional Western Residences along Roosevelt Street
Location 7	Easternmost End of Stockbridge Street

Instrumentation

All sound level measurements during both noise surveys were collected with

a sound meter that complies with Type 1 tolerance requirements of the American National Standards Institute and was field calibrated before and after each measurement set. A calibration laboratory certified the equipment within the preceding 12-month period using references traceable to the National Institute of Standards and Technology.

Ambient Survey Results

It was observed during both noise surveys that community ambient sound levels were generally controlled by noise from local traffic on Route 116 and University campus roadways. In addition, natural sounds such as birdcalls and wind-induced vegetation rustle were also audible during the spring survey. Table 7 below summarizes the short-term background sound levels (L_{90}) measured during daytime and early morning periods in both May 2002 and January 2003.

Table 7

Summary of Short-Term Background Measurement Results (L_{90})

Position	Daytime (5/15/02)	Daytime (1/29/03)	Early Morning (5/16/02)	Early Morning (1/30/03)
Location 1	48	41	38	41

Location 2	52	51	43	46
Location 3	51	46	44	44
Location 4	58	51	47	45
Location 5	46	44	41	39
Location 6	50	51	34	37
Location 7	N/A	51	N/A	39
Spatial Average	51	48	41	42

Acoustical Modeling

A three-dimensional acoustical model of the CHP was developed using SoundPLAN Version 5.6 to predict noise levels at the property boundary of the site, off-site nearby residences, and on-campus noise sensitive receptors.

The results of the broadband (A-weighted) compliance assessment are summarized in Table 8 below. Future ambient levels at the nearest receivers are predicted to be no more than 3.0 dBA higher than the lowest ambient levels (L_{90}) obtained during either the May 2002 or January 2003 surveys. The results of the octave band (tonal) compliance assessment showed that no octave band level exceeds adjacent octave band levels by 3 decibels at either nearby receptors or at the property line. Therefore, noise emissions produced during operation of the CHP are expected to fully comply with the broadband and tonal limits of Policy 90-001 and BACT.

Table 8

Expected Future Sound Levels at Various Receivers

A-Weighted Sound Level (dBA)	Position						
	Location 1	Location 2	Location 3	Location 4	Location 5	Location 6	Location 7
Lowest Measured Ambient Noise Level (L_{90})	38.1	43.2	43.6	45.0	38.9	34.2	39.4
Predicted Noise Level from New Equipment (L_{EQ})	28.0	51.1	43.2	28.9	35.4	29.5	39.4
Future Projected Ambient Noise Level	38.5	51.8	46.4	45.1	40.5	35.5	42.4
Broadband (A-Weighted) Ambient Increase	+0.4	+8.6	+2.8	+0.1	+1.6	+1.3	+3.0

Conceptual Noise Controls

In order to comply with MassDEP noise policy and BACT, acoustical controls are incorporated into the design of the proposed CHP. Although the specific type and amount of mitigation will be selected during the detailed design phase of the project, a successful noise control program will include, at a minimum, the following components:

- Dual-stage silencers providing approximately 70 decibels (A-weighted) of attenuation for combustion turbine air intake noise.

- HRSG and catalytic converters providing approximately 43 decibels (A-weighted) of attenuation for combustion turbine exhaust noise.

- A thermal generation building enclosing major pieces of equipment and providing a Sound Transmission Class rating of 35 dB.

- Low-noise generation building ventilation fans and acoustically treated air intake and discharge ventilation louvers.

- Gas compressor located within an acoustically designed enclosure with minimal ventilation openings.

- High performance boiler steam vent silencers providing approximately 68 decibels of attenuation (A-weighted).

PROVISIONS OF APPROVAL

It is the opinion of MassDEP that the CHP proposed by UMBA is consistent with modern air pollution control technology and Best Available Control Technology. MassDEP hereby proposes to grant a Conditional Approval for the installations described herein and in the submittal pursuant to Regulation 310 CMR 7.02(5)(a) of the "Regulations for the Control of Air Pollution in the Pioneer Valley Air Pollution Control District", subject to the following provisions:

Emission Limits & Restrictions

1. UMass–Amherst shall keep emission rates at the lowest practical level at all times, but shall not exceed the emission limits specified in Tables 9a, 9b, and 9c as follows:

Table 9a

EU #	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards (1)(2)(3) natural gas		ULSD oil		Restrictions ULSD oil
CTG/HRSG & duct burner (except where noted)	natural gas or ULSD oil	Particulate Matter (4)	6.89 lb/hr	0.030 lb/MMBtu	6.64 lb/hr	0.030 lb/MMBtu	≤ 2,229,611 gallons (6) (combustion turbine only; rolling 12 month total)
		PM_{10} (5)	6.89 lb/hr	0.030 lb/MMBtu	7.97 lb/hr	0.036 lb/MMBtu	
		Particulate matter <10 µm diameter	4.14 lb/hr w/o duct burner	0.030 lb/MMBtu w/o duct burner	4.71 lb/hr w/o duct burner	0.036 lb/MMBtu w/o duct burner	
		VOC	0.44 lb/hr	0.0041 lb/MMBtu	0.71 lb/hr	0.0074 lb/MMBtu	
		Sulfur Dioxide	0.50 lb/hr	0.0022 lb/MMBtu	0.40 lb/hr	0.0018 lb/MMBtu	
		Carbon Monoxide	3.07 lb/hr	5.0 ppmvd (7)	2.96 lb/hr	5.0 ppmvd (7)	
		Nitrogen Oxides (10)	2.52 lb/hr	2.5 ppmvd (7)	5.84 lb/hr	6.0 ppmvd (7)	
		Ammonia (11)	0.75 lb/hr	2.5 ppmvd (7,8) 7.5 ppmvd (7,9)	0.72 lb/hr	4.0 ppmvd (7,8) 10.0 ppmvd (7,9)	

(1) The emission rates for the CTG/Duct burner are based on worst case emission rate (100% load, duct burner on except where noted, and 0°F ambient temp.),

(2) The lb/hr and lb/MMBtu emission rates are based on a 1-hour block average, and do not apply during startup or shutdown, except as noted otherwise.

(3) The PM_{10} emission limit is applicable during startup and shutdown, as specified in the EPA-New England PSD permit. All other criteria pollutant mass emission rates during start-up and shutdown will be quantified during initial compliance testing and used in the determination of annual mass emissions.

(4) Particulate matter measured as filterable particulate (front-half catch) using applicable procedures specified in 40 CFR Part 60 Appendix A, Method 5.

(5) Particulate matter as measured by 40 CFR 51, Appendix M, Test Method 201 or 201A and Test Method 202.

(6) Additional ULSD oil may be burned if a fuel BACT analysis is submitted to MassDEP and an approval is issued by MassDEP in writing.

(7) "ppmvd" emission limits are corrected to 15% O_2 for CTG/Duct burner and corrected to 3% O_2 for the boilers.

(8) Ammonia ppmvd limit is based on a 1-hour block average during NORMAL OPERATION, and a 24-hour block average for ALL OTHER TIMES.

(9) Ammonia ppmvd limit is based on a 1-hour block average during TRANSIENT OPERATION.

(10) NOx emissions are limited to 18.7 ppmvd (corrected to 15% O_2) and 19 lb/hr during < 0°F ambient temperature conditions, which cannot exceed 300 hours per calendar year.

(11) Ammonia emissions are limited to 20 ppmvd (corrected to 15% O_2) and 7.2 lb/hr during < 0°F ambient temperature conditions, which cannot exceed 300 hours per calendar year.

Table 9b

EU #	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards (1)(2)(3)				Restrictions ULSD oil
			natural gas		ULSD oil		
Boiler #200 High	natural gas or ULSD oil	Particulate Matter (4)	3.59 lb/hr	0.020 lb/MMBtu	3.47 lb/hr	0.020 lb/MMBtu	Oct. 1st – April 30th ≤ 15,508,252 gallons (6) and
		PM_{10} (5) – particulate matter <10 µm dia.	3.59 lb/hr	0.020 lb/MMBtu	5.21 lb/hr	0.03 lb/MMBtu	
		VOC	0.95 lb/hr	0.0054 lb/MMBtu	0.44 lb/hr	0.0025 lb/MMBtu	

Table 9b

EU #	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards (1)(2)(3) natural gas		ULSD oil		Restrictions ULSD oil
Pressure Boiler		Sulfur Dioxide	0.40 lb/hr	0.0022 lb/MMBtu	0.28 lb/hr	0.0016 lb/MMBtu	May 1st – Sept. 30th ≤ 6,357,830 gallons (6)
		Carbon Monoxide	3.90 lb/hr	0.022 lb/MMBtu 20.0 ppmvd (7)	4.54 lb/hr	0.026 lb/MMBtu 25.0 ppmvd (7)	
		Nitrogen Oxides	1.60 lb/hr	0.009 lb/MMBtu 5.0 ppmvd (7)	2.68 lb/hr	0.016 lb/MMBtu 9.0 ppmvd (7)	
		Ammonia	0.16 lb/hr	2.5 ppmvd (7,8) 7.5 ppmvd (7,9)	0.17 lb/hr	4.0 ppmvd (7,8) 10.0 ppmvd (7,9)	
Boilers #300 #400 Low Pressure Boilers	natural gas or ULSD oil	Particulate Matter (4)	3.24 lb/hr	0.020 lb/MMBtu	3.13 lb/hr	0.020 lb/MMBtu	
		PM_{10} (5) – particulate matter <10 µm dia.	3.24 lb/hr	0.020 lb/MMBtu	4.68 lb/hr	0.03 lb/MMBtu	
		VOC	0.87 lb/hr	0.0054 lb/MMBtu	0.39 lb/hr	0.0025 lb/MMBtu	
		Sulfur Dioxide	0.36 lb/hr	0.0022lb/MMBtu	0.25 lb/hr	0.0016 lb/MMBtu	
		Carbon Monoxide	3.52 lb/hr	0.022 lb/MMBtu 20.0 ppmvd (7)	4.08 lb/hr	0.026 lb/MMBtu 25.0 ppmvd (7)	
		Nitrogen Oxides	1.45 lb/hr	0.009 lb/MMBtu 5.0 ppmvd (7)	2.42 lb/hr	0.0155 lb/MMBtu 9.0 ppmvd (7)	

Table 9b

EU #	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards (1)(2)(3)				Restrictions ULSD oil
			natural gas		ULSD oil		
		Ammonia	0.14 lb/hr	2.5 ppmvd (7,8) 7.5 ppmvd (7,9)	0.15 lb/hr	4.0 ppmvd (7,8) 10.0 ppmvd (7,9)	
CHP Facility-Wide	ULSD oil	Sulfur in fuel	≤ 0.8 grains / 100ft^3		≤ 0.0015 % by wt.		≤ 24,116,129 gallons (6) (rolling 12-month total)

(1) The boilers emission limits are for single boiler units operating at 100% load.

(2) The lb/hr and lb/MMBtu emission rates are based on a 1-hour block average, and do not apply during startup or shutdown, except as noted otherwise.

(3) The PM_{10} emission limit is applicable during startup and shutdown as specified in the EPA-New England PSD permit. All other criteria pollutant mass emission rates during start-up and shutdown will be quantified during initial compliance testing and used in the determination of annual mass emissions.

(4) Particulate matter measured as filterable particulate (front-half catch) using applicable procedures specified in 40 CFR Part 60 Appendix A, Method 5.

(5) Particulate matter as measured by 40 CFR 51, Appendix M, Test Method 201 or 201A and Test Method 202.

(6) Additional ULSD oil may be burned if a fuel BACT analysis is submitted to MassDEP and an approval is issued by MassDEP in writing.

(7) "ppmvd" emission limits are corrected to 15% O_2 for CTG/Duct burner and corrected to 3% O_2 for the boilers.

(8) Ammonia ppmvd limit is based on a 1-hour block average during NORMAL OPERATION, and a 24-hour block average for ALL OTHER TIMES.

(9) Ammonia ppmvd limit is based on a 1-hour block average during TRANSIENT OPERATION.

Table 9c

EU #	Fuel or Raw Material	Pollutant	Stack Emission Limit / Standards		Restrictions
			natural gas	ULSD oil	ULSD oil
CTG/HRSG & duct burner	natural gas or ULSD oil	Smoke (during 1st hour of startup or shutdown)	≤ 10% (6-minute average)	No. 1 of the Chart no more than 6 minutes during any one hour, no time to exceed No. 2 of the Chart (1)	Listed in Tables 9a and 9b
		Opacity (during 1st hour of startup or shutdown)	≤ 10% (6-minute average)	≤ 20%, except 20 to ≤ 40% for ≤ 2 minutes during any one hour.	
		Smoke/Opacity (at all times except 1st hour of startup or shutdown)	≤ 10% (6-minute average)		
Boilers #200 #300 #400	natural gas or ULSD oil	Smoke/Opacity	≤ 10% (6-minute average, including startup/shutdown/fuel transfer) (2)		

(1) Chart means the Ringelmann Scale for grading the density of smoke, as published by the United States Bureau of Mines and as referred to in the Bureau of Mines Information Circular No. 8333.

(2) Procedures for responding to Smoke/Opacity from the boilers, as indicated by in-stack COMS, are found in the Boiler Opacity SOP approved by MassDEP August 24, 2012 and as amended.

Definitions:

NORMAL OPERATION: A 1-hour block period during which the difference between the highest and lowest firing rate for the combustion turbine, duct burner, or a boiler is less than 30 MMBtu/hr.

TRANSIENT A 1-hour block period – and the subsequent hour – during which the difference between OPERATION: the highest and lowest firing rate for the combustion turbine, duct burner, or a boiler is 30 MMBtu/hr or greater.

ALL OTHER TIMES: A 24-hour block period, which may include both normal and transient operation.

STARTUP: Startup is defined as the time when a flame in the emission unit is initiated and the emission unit operation achieves minimum sustained operating load. The duration of startups shall be no greater than 4.0 hours.

SHUTDOWN: Shutdown is defined as the time when the emission unit operation is between minimum sustained operating load and flame-out in the emission unit occurs. The duration of shutdowns shall be no greater than 2.0 hours

FUEL SWITCHING: Fuel Switching is defined as the time when the emission unit operation is changed from oil to natural gas, or from natural gas to oil. The duration of fuel switching shall be no greater than 2.0 hours.

2. UMass–Amherst is subject to the monitoring, testing, record-keeping, reporting, and "special conditions" as contained in Tables 10a-e, 11, 12, and 13 and the applicable requirements as contained in Tables 9a, 9b, and 9c.

Table 10	
EU	**Testing Requirements**
CTG & Duct Burner & Boilers	STACK EMISSIONS TESTING UMass–Amherst shall 1. The owner/operator shall perform emission testing upon request of MassDEP. The owner/operator shall submit emissions test protocol(s) to MassDEP for review and written approval at least 30 days prior to the date of actual testing. The owner/operator shall submit the final emissions test report(s) to the MassDEP within 60 days after the completion of each of the tests. NOISE TESTING UMass–Amherst shall 2 Ensure that the facility is designed, constructed, operated and maintained such that at all times: a. No condition of air pollution will be caused by emissions of sound as provided in 310 CMR 7.01; b. No sound emissions resulting in noise will occur as provided in 310 CMR 7.10 and MassDEP's Policy 90-001 other than approved herein; and c. Sound emissions from the facility will not exceed the levels set forth in Table 8 at the locations identified in Table 6 and in the Application.
CHP Plant-Wide	UMass–Amherst shall 3. MassDEP reserves the right to require additional noise testing if in the opinion of MassDEP such additional measurements are necessary to determine compliance with the Air Pollution Control Regulations and MassDEP noise policies.

Table 10

EU	**Monitoring Requirements**
CTG & Duct Burner & Boilers	<u>OPACITY MONITOR</u> UMass–Amherst shall 4. Calibrate, operate, and maintain a Data Acquisition and Handling System(s) (DAHS) and opacity monitor to continuously monitor and record opacity from the subject emission unit stack(s). 5. Equip the opacity monitor with audible and visible alarms which activate when opacity exceeds the limits established herein. 6. Operate the opacity monitor at all times the subject emission unit is operating, except for periods of calibration checks, zero and span adjustments, and preventive maintenance. 7. Obtain and record emission data from each opacity monitor (except for periods of calibration checks, zero and span adjustments, and preventive maintenance) as follows: a. For at least 75% of the operating days in any calendar month, capture opacity data for at least 75% of the operating hours on those operating day(s), (an operating day is any calendar day an emission unit operates for any length of time and at any load), (For instance if a boiler operated at any load and for any amount of time for 12 days in September, at least 9 of those days must have data capture for at least 75% of the hours operated that day) b. Capture opacity data for at least 95% of the operating hours that the CTG or package boiler operates in each calendar quarter, (an operating hour is any hour or part of an hour an emission unit operates at any load) 8. Maintain on-site for the opacity monitor an adequate supply of spare parts to maintain the on-line

	availability and data capture requirements contained herein. 9. Use and maintain the opacity monitor as a “direct-compliance” monitor to measure compliance with the opacity limit contained herein. A “Direct-compliance” monitor generates data that legally documents the compliance status of a source. MassDEP may also use the opacity monitor or any credible evidence in its determination of compliance with the limits and conditions specified in this approval. Use of the boiler opacity monitors as "direct compliance" monitors applies only when the Boiler Opacity SOP procedures, approved by MassDEP August 24, 2012 (and as amended) are not adhered to during an opacity event and the opacity is determined to be caused by inefficient combustion. 10. Ensure that the opacity monitor equipment complies with MassDEP approved performance and location specifications, and conforms with the EPA monitoring specifications in 40 CFR Part 60.

Table 10	
EU	**Monitoring Requirements**
CTG & Duct Burner & Boilers	<u>CEMs for NOx, CO, NH_3, & diluent gas</u> UMass–Amherst shall 11. Calibrate, operate, and maintain a data acquisition and handling system(s) (DAHS) and stack CEMs to continuously monitor and record flue gas emissions of NO_x, CO, NH_3, and diluent gas from the subject emission unit stack. 12. Equip each CEMs with audible and visible alarms which activate when emissions exceed the limits established herein. 13. Operate all CEMs at all times the subject emission unit is operating, except for periods of CEMs calibration checks, zero and span adjustments, and preventive maintenance. 14. Obtain and record emission data from each CEMs (except for periods of calibration checks, zero and span adjustments, and preventive maintenance) as follows: a. For at least 75% of the operating days in any calendar month, capture CEM data for at least 75% of the operating hours on those operating day(s), (an operating day is any calendar day an emission unit operates for any length of time and at any load), (For instance if a boiler operated at any load and for any amount of time for 12 days in September, at least 9 of those days must have data capture for at least 75% of the hours operated that day) b. Capture CEM data for at least 95% of the operating hours that the CTG or package boiler operates in each calendar quarter,

	(an operating hour is any hour or part of an hour an emission unit operates at any load) 15. Maintain on-site for the CEMs equipment an adequate supply of spare parts to maintain the on-line availability and data capture requirements contained herein. 16. Use and maintain all its CEMs systems as “direct-compliance” monitors to measure compliance with the emission limits contained herein. “Direct-compliance” monitors generate data that legally documents the compliance status of a source. MassDEP may also use the CEMs or any credible evidence in its determination of compliance with the limits and conditions specified in this approval. 17. Ensure that the CEMS equipment complies with MassDEP approved performance and location specifications, and conforms with the EPA monitoring specifications specified in 40 CFR Part 60.

EU	Monitoring Requirements
CTG & Duct Burner & Boilers	TEMPERATURE MONITORING SYSTEM UMass–Amherst shall 18. Calibrate, operate, and maintain a temperature monitoring system to continuously monitor and record the inlet temperatures to the SCR and the CO catalysts for the CTG/HRSG and the boilers. 19. Equip each temperature monitoring system with audible and visible alarms which activate when these temperatures deviate from normal operating temperatures established during the initial compliance testing. 20. Operate all temperature monitoring equipment at all times the CTG or a boiler is operating, except for periods of calibration checks, zero and span adjustments, and preventive maintenance. 21. Obtain and record temperature data from each temperature monitor specified herein (except for periods of calibration checks, zero and span adjustments, and preventive maintenance) as follows: a. For at least 75% of the operating days in any calendar month, capture temperature monitor data for at least 75% of the operating hours on those operating day(s), (an operating day is any calendar day an emission unit operates for any length of time and at any load), (For instance if a boiler operated at any load and for any amount of time for 12 days in September, at least 9 of those days must have data capture for at least 75% of the hours operated that day) b. Capture temperature monitor data for at least 95% of the operating hours that the CTG or package boiler operates in each calendar quarter, (an operating hour is any hour or part of an hour an emission unit operates at any load) 22. Maintain on-site for the temperature monitoring equipment an adequate supply of spare parts to maintain the on-line availability and data capture requirements contained herein. 23. Ensure that all temperature monitors and recording equipment comply with MassDEP approved performance and location specifications.

Table 11	
EU	**Recordkeeping Requirements**
CHP Plant-Wide	UMass–Amherst shall 1. Maintain a log to record problems, upsets or failures associated with the emission control system, CEMs, temperature monitors, or ammonia handling system. 2. Maintain records of all periods of excess emissions, even if attributable to an emergency/malfunction or startup/shutdown, and shall quantify these emissions and include them in the determination of annual emissions. 3. Maintain records of all measurements, performance evaluations, calibration checks, maintenance, and adjustments for each CEMS and temperature monitoring system device. 4. Maintain on-site permanent records of output from CEMS and temperature monitoring systems, and make these records available to MassDEP on request. 5. Record for each unit on a daily basis the type(s) of fuel burned, heat content of each fuel, total heating value of the fuel consumed, and the actual emission rate for each pollutant for emission units demonstrating compliance with CEMS. 6. Demonstrate compliance for each new shipment of ULSD oil received with the % sulfur-in-fuel requirement specified herein by <u>testing certification</u> or <u>shipping receipt certification</u>, either of which must certify that the shipment complies with the ASTM specifications for distillate oil and the specified % sulfur-in-fuel requirement. 7. Maintain for the life of the facility all operating and monitoring records and logs. UMass–Amherst shall make available to MassDEP for inspection upon request the five most recent years' data.
Emergency Generator	UMass–Amherst shall 8. Establish a recordkeeping system of sufficient detail that documents that the emergency generator does

	not exceed 300 hours operation each per rolling 12-month period.

Table 12	
EU	**Reporting Requirements**

CHP Plant-Wide	UMass–Amherst shall 1. Submit to MassDEP, in a format acceptable to MassDEP, a semi-annual report postmarked by January 30th and July 30th of each year, which minimally contains for the prior calendar 6-month period the following information: a. Reports from the facility CEMS and temperature monitors, containing summary data, and b. For each period of excess emissions or excursions from allowable operating conditions, UMass–Amherst shall list the duration, cause (including whether it is attributable to a malfunction or emergency), the response taken, and the amount of excess emissions. Periods of excess emissions shall include malfunctions, emergency, and upsets or failures associated with the emission control system, CEMS or temperature monitors. c. A tabulation of periods of oil use. <u>EMERGENCY / MALFUNCTION</u> UMass–Amherst shall 2. Notify MassDEP in writing within three (3) business days of any emergency or malfunction, when the emergency or malfunction may cause emissions to the ambient air that exceed any emission limits by 10% or more over the standard, including noise limits contained herein; or cause a condition of air pollution, or otherwise violate a term or condition of this approval. The written notice must contain a description of the emergency or malfunction, any steps taken to mitigate emissions, an estimate of the quantity of emissions released as a result of the emergency or malfunction and any corrective actions taken. 3. Notify MassDEP immediately by telephone and in writing within three (3) business days, following the release or the threat of a release of ammonia, and/or upsets or malfunctions to the ammonia handling or delivery systems, and comply with all notification procedures required under M.G.L. c. 21 E - Spill Notification Regulations, and the Massachusetts Contingency Plan, 310 CMR 40.000. 4. If the initial notice was not provided within three (3) business days, then UMass–Amherst shall have the burden of establishing that the initial notice was provided as soon as reasonably practical in any subsequent enforcement action. 5. The reporting requirements of this Conditional Approval for an emergency or malfunction do not

	supersede, limit, or make inapplicable any reporting obligation under federal law, including but not limited to 42 U.S.C. sections 9603 or 11004. 6. An emergency and/or malfunction may constitute an affirmative defense to an action brought for noncompliance with emission limitations if UMass–Amherst demonstrates the affirmative defense of emergency or malfunction through properly signed, contemporaneous operating logs and other relevant evidence that shows that: a. an emergency or malfunction occurred and that the cause(s) of the emergency or malfunction can be identified; b. UMass–Amherst was, at that time, operating the facility in a correct manner; c. during the period of the emergency or malfunction, UMass–Amherst took all reasonable steps as expeditiously as possible to minimize levels of emissions that exceeded the emission standards, or other requirements in this approval; and d. UMass–Amherst submitted notice of the emergency or malfunction to MassDEP in writing within three (3) business days of the emergency or malfunction. The written notice must contain a description of the emergency or malfunction, any steps taken to mitigate emissions, an estimate of the quantity of emissions released as a result of the emergency or malfunction and any corrective actions taken.

Table 13	
EU	**Special Terms & Conditions**
CTG & Duct Burner	UMass–Amherst 1. Shall only burn natural gas or ULSD oil in the CTG , and only natural gas in the duct burner. 2. Shall burn natural gas in the CTG to the full extent of its availability, except as provided in provision 3 below. 3. May burn ULSD oil in the CTG (and may burn ULSD oil in excess of the allotment specified in Table 9a and 9b) if supported by the results of a fuel BACT analysis that is approved by MassDEP in writing.
Boilers	UMass–Amherst 4. Shall only burn natural gas or ULSD oil in the boilers. 5. Shall tune each boiler annually in accordance with procedures contained in EPA 340/1-83-023 "Combustion Efficiency Optimization Manual for Operators of Oil and Gas Fired Boilers" (or equivalent) with the goal of reducing air pollutant emissions, including NO_x and CO, to optimum levels.
Emergency Engine	UMass–Amherst 6. Shall ensure that the sulfur content at the time of purchase of oil to be used as fuel in the emergency generator conforms with the then current sulfur limit applied to on-road specification oil as defined in the Code of Federal Regulations (at the time of issuance of this permit, defined in 40 CFR § 80.29(a)(i)). 7. Shall ensure that the emergency generator be equipped with an exhaust silencer so that sound emissions will not cause or contribute to a condition of air pollution 8. Shall ensure that the emergency generator utilizes an exhaust stack with a minimum height of 10 feet above the facility rooftop or the emergency engine enclosure, whichever is lower, and that discharges so as to not cause or contribute to a condition of air pollution.

	9. Shall ensure that the emergency generator conforms with any other applicable requirements detailed in Regulation 310 CMR 7.26(42).
Plant Wide	UMass–Amherst 10. Shall comply with all applicable NSPS requirements for CTG and duct burner found in 40 CFR Part 60, Subpart KKKK. 11. Shall comply with all applicable NSPS requirements found in 40 CFR Part 60, Subpart Db for each of the three boilers. 12. Shall properly train all personnel to operate the facility monitoring and control equipment in accordance with vendor specifications and all applicable regulations. This training shall be updated at least once annually. MassDEP personnel shall be informed of scheduled training sessions at least 30 days in advance and MassDEP personnel shall be allowed access to attend these training sessions.

General Requirements

1. Suspension – This Conditional Approval may be suspended, modified, or revoked by MassDEP if, at any time, MassDEP determines that UMass–Amherst is violating any condition or part of the approval.

2. Other Regulations – This Conditional Approval does not negate the responsibility of UMass–Amherst to comply with this or any other applicable federal, state, or local regulations now or in the future. This Conditional Approval does not imply compliance with any other applicable federal, state or local regulation now or in the future.

3. Fuel Utilization Facility Testing – In accordance with 310 CMR 7.04(4)(a), UMass–Amherst shall have the fuel utilization facility (all combustion units) inspected and maintained in accordance with the manufacturer's recommendations and tested for efficient operation at least once in each calendar year. The results of said inspection, maintenance and testing and the date upon which it was performed shall be recorded and posted conspicuously on or near the permitted equipment.

4. Compliance Determination – Compliance with the emission limits contained herein shall be determined by data collected by CEMS and temperature monitoring system, as specified within this Conditional Approval and/or by stack emission test methods as approved by MassDEP. MassDEP may also use any credible evidence in its determination of compliance with the limits and conditions specified in these approvals.

This Conditional Approval consists of the application materials and this Approval letter. If conflicting information is found between these two documents, then the requirements of the Approval letter shall take precedence over the documentation in the application materials.

This Conditional Approval pertains only to the air quality control aspect of the proposal and does not negate the responsibility of the owners or operators to comply with other applicable state, local, or federal laws and regulations.

This Conditional Approval is an action of MassDEP. If you are aggrieved by this action, you may request an adjudicatory hearing. A request for a hearing must be made in writing and postmarked within twenty-one (21) days of the date you received this document.

Under 310 CMR 1.01(6)(b), the request must state clearly and concisely the facts which are the grounds for the request and the relief sought. Additionally, the request must state why the Conditional Approval is not consistent with applicable laws and regulations.

The hearing request along with a valid check payable to the Commonwealth of Massachusetts in the amount of one hundred dollars ($100) must be mailed to:

Commonwealth of Massachusetts

Department of Environmental Protection

P. O. Box 4062

Boston, MA 02211

The request will be dismissed if the filing fee is not paid, unless the appellant is exempt or granted a waiver as described below.

The filing fee is not required if the appellant is a city or town (or municipal agency), county, or district of the Commonwealth of Massachusetts, or a municipal housing authority.

MassDEP may waive the adjudicatory hearing filing fee for a person who shows that paying the fee will create an undue financial hardship. A person seeking a waiver must file, together with the hearing

request as provided above, an affidavit setting forth the facts believed to support the claim of undue financial hardship.

If you have any questions regarding this Conditional Approval, please do not hesitate to contact John Kirzec of the Western Regional Office at 755-2225.

Sincerely,

This final document copy is being provided to you electronically by the Department of Environmental Protection. A signed copy of this document is on file at the DEP office listed on the letterhead.

_____

Marc Simpson

Permit Chief

Western Region

UMass CHP-2009-12-31 amended 2012-09-14.doc

cc: Tom Stoughton – Senior Vice President

Woodard & Curran

41 Hutchins Drive

Portland, ME 04102

ecc: Ida E. McDonnell, Manager

Air Permits, Toxics and Indoor Air Unit

EPA-New England, Region 1

5 Post Office Sq. Suite 100

Mail Code OEP05-2

Boston, MA 02109-3912

Donald Dahl

Air Permits, Toxics and Indoor Air Unit

EPA-New England, Region 1

5 Post Office Square; Suite 100

Boston, MA 02109-3912

David Howland, WERO

Peter Czapienski, WERO

Roberta Baker, WERO

Yi Tian, MassDEP, Boston

Karen Regas, MassDEP, Boston

APPENDIX

Table A

Solar 100 Combustion Turbine Performance Data

Solar 100 Performance Data	100% Load											
	Natural Gas						ULSD Oil					
Ambient Temperature (°F)	0	0	60	60	100	100	0	0	60	60	100	100
Relative Humidity (%)	60	60	60	60	60	60	60	60	60	60	60	60
Duct Burner (Off/On)	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes
Output (kW)	11,835	11,835	10,250	10,250	8,574	8,574	11,712	11,712	9,582	9,582	7,715	7,715
Gas Consumption (lb/hr) (1)	6,038	10,058	5,355	8,773	4,720	7,672	0	3,957	0	3,344	0	2,816
ULSD Oil Consumption (lb/hr) (1)	0	0	0	0	0	0	6,724	6,724	5,684	5,684	4,925	4,925
Heat Input (MMBtu/hr)	137.91	229.71	122.30	200.30	107.8	175.2	130.91	221.31	110.66	187.06	95.89	157.19

(1) The fuel consumption is based upon higher heating values of 1,022 Btu/scf for natural gas and 134,343 Btu/gal for ULSD oil.

Table B

High Pressure ("HP") and Low Pressure ("LP")

Boiler Performance Data

Boiler Performance Data	HP Boiler 100% Load		LP Boiler 100% Load	
	Natural Gas	ULSD Oil	Natural Gas	ULSD Oil
Ambient Temperature (°F)	80	80	80	80
Steam Flow Rate (lb/hr)	125,000	125,000	125,000	125,000
Steam Temperature (°F)	740	740	466	466

Steam Pressure (psig)	625	625	200	200
Fuel Consumption (lb/hr) (1)	7,956	8,907	7,174	8,017
Heat Input (MMBtu/hr)	179.72	173.41	162.06	156.07

(1) The fuel consumption is based upon higher heating values of 1,022 Btu/scf for natural gas and 134,343 Btu/gal for ULSD oil.

Table C

Design Data for Petroleum and Chemical Storage Tanks

Description	Number	Type (1)	Capacity (gallons)(2)
Condensate Storage	1	Vertical	214,339
Raw Water Storage	1	Vertical	238,000
Oil Storage	2	Vertical	234,810
Ammonia Storage	2	Horizontal	5,000
Waste Neutralization	1	Vertical	20,000
Bulk H_2SO_4 Storage	1	Vertical	2,000
Bulk NaOH Storage	1	Vertical	2,000
Bulk Sodium Phosphate Storage	1	Vertical	275
Bulk Amine Storage	1	Vertical	275
Bulk O_2 Scavenger Storage	1	Vertical	275
Brine Storage	1	Vertical	305
Amine Storage	1	Vertical	500
Amine Storage	1	Vertical	80
Water Treatment Chemicals	4	Drums	50
Emergency Generator Storage Tank	1	n/a	1,500

(1) The storage tanks are either horizontal or vertical fixed-roof tanks.

(2) The capacity is for each storage tank.

Table D

Criteria Pollutant Emissions from Combustion Turbine / Duct Burner

Pollutant/Parameter	Fuel Type											
	Natural Gas (100% load)						ULSD Oil (100% load)					
Ambient Temperature (°F)	0	0	60	60	100	100	0	0	60	60	100	100
Relative Humidity (%)	60	60	60	60	60	60	60	60	60	60	60	60
Duct Burner (Off/On)	Off	On	Off	On	Off	On	Off	On	Off	On	Off	On
NO_x (ppmvd)	2.5	2.5	2.5	2.5	2.5	2.5	6.0	6.0	6.0	6.0	6.0	6.0
NO_x (lb/hr)	1.40	2.52	1.25	2.23	1.15	2.04	3.28	5.84	2.80	4.99	2.52	4.47
CO (ppmvd)	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
CO (lb/hr)	1.70	3.07	1.53	2.71	1.40	2.48	1.66	2.96	1.42	2.53	1.28	2.26
PM_{10} (lb/hr)	4.14	6.89	3.67	6.01	3.23	5.26	3.93	6.64	3.32	5.61	2.88	4.72
SO_2 (lb/hr)	0.30	0.50	0.27	0.44	0.23	0.38	0.20	0.40	0.17	0.34	0.15	0.29
VOC (lb/hr)	0.44	0.44	0.44	0.44	0.44	0.44	0.71	0.71	0.71	0.71	0.71	0.71
H_2SO_4 mist (lb/hr)	0.05	0.08	0.04	0.07	0.04	0.06	0.031	0.061	0.026	0.052	0.023	0.044
NH_3 (lb/hr)	0.41	0.75	0.37	0.66	0.34	0.60	0.40	0.72	0.35	0.61	0.31	0.55

Table E-1

Criteria Pollutant Emissions from the High Pressure Boiler

Pollutant	Fuel Type					
	Natural Gas (100% load)			ULSD Oil (100% load)		
	ppmvd	lb/hr	lb/MMBtu	ppmvd	lb/hr	lb/MMBtu

NO_x	5.00	1.60	0.0089	9.00	2.68	0.0155
CO	20.00	3.90	0.0217	25.00	4.54	0.0262
PM_{10}	–	3.59	0.0200	–	5.21	0.0300
SO_2	–	0.40	0.0022	–	0.28	0.0016
VOC	–	0.95	0.0054	–	0.44	0.0025
H_2SO_4 mist	–	0.06	–	–	0.04	–
NH_3	–	0.16	–	–	0.17	–

Table E-2

Criteria Pollutant Emissions from the Low Pressure Boilers (each unit)

	Fuel Type					
	Natural Gas (100% load)			ULSD Oil (100% load)		
Pollutant	ppmvd	lb/hr	lb/MMBtu	ppmvd	lb/hr	lb/MMBtu
NO_x	5.00	1.45	0.0089	9.00	2.42	0.0155
CO	20.00	3.52	0.0217	25.00	4.08	0.0261
PM_{10}	–	3.24	0.0200	–	4.68	0.0300
SO_2	–	0.36	0.0022	–	0.25	0.0016
VOC	–	0.87	0.0054	–	0.39	0.0025
H_2SO_4 mist	–	0.06	–	–	0.04	–
NH_3	–	0.14	–	–	0.15	–

Table F

Emergency Generator Performance Data (1)

Pollutant	Natural Gas lb/hr	Natural Gas tons/yr	ULSD Oil lb/hr	ULSD Oil tons/yr
NO_x	12.91	1.94	12.91	1.94
CO	6.95	1.04	6.95	1.04
PM_{10}	0.40	0.06	0.40	0.06
SO_2	0.02	0.003	0.47	0.07
VOC	1.83	0.27	0.82	0.12
Heat Input	9.13 MMBtu/hr		9.13 MMBtu/hr	

(1) Based on manufacturer's data or emission factors cited in EPA Document No. AP-42 Section 3.4.

Table G

Summary of natural gas/oil 'cut-point'

in the CHP BACT Analysis

Parameter	Value
Base Gas Usage (MMBtu/yr)	678,024
Future Gas Usage (MMBtu/yr)	1,482,564
Incremental Gas Usage (MMBtu/yr)	804,540
Incremental Gas Cost ($/MMBtu)	2.88
Base NOx Emissions (tpy)	209.73

Future NOx Emissions (tpy)	11.14
NOx Reduction (tpy)	198.59
SCR Fixed Capital Costs ($/yr)	214,806
SCR Annual Operating Costs ($/yr)	251,067
Annual Fuel Costs ($/yr)	2,314,420
Incremental Annual Costs ($/yr)	2,780,293
NOx Cost Effectiveness ($/ton)	14,000