TETRA TECH

December 21, 2012

Mr. James Belsky, Permit Chief
MassDEP Northeast Region
205B Lowell Street
Wilmington, MA 01887

Re: ***Major Comprehensive Plan Approval Application – Salem Harbor Redevelopment Project (Transmittal Number X254064)***

Dear Mr. Belsky:

On behalf of Footprint Power Salem Harbor Development LP, enclosed please find two copies of a Major Comprehensive Plan Approval Application for the Salem Harbor Redevelopment Project at 24 Fort Avenue in Salem. A pre-application meeting for the project was held with you on June 7, 2012.

If you have any questions, please contact Mr. George Lipka (who has provided the P.E. stamp on the application) at (617) 443-7568, or me at (617) 803-7809.

Sincerely,

Keith H. Kennedy

Keith H. Kennedy
Senior Consultant – Energy Programs

Enclosures

Tetra Tech, Inc.
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www.tetratech.com

Comprehensive Plan Approval Application

Salem Harbor Redevelopment Project
Salem, Massachusetts

Submitted to:
Massachusetts Department of Environmental Protection
Northeast Region
205B Lowell Street
Wilmington, MA 01887

Prepared on Behalf of:
Footprint Power Salem Harbor Development LP
1140 Route 22 East, Suite 303
Bridgewater, NJ 08807

Prepared by:
Tetra Tech
160 Federal Street
Boston, MA 02110

December 2012

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APPENDICES

1.0 INTRODUCTION

Footprint Power Salem Harbor Development LP (Footprint Power or Footprint) proposes to construct and operate a nominal 630 megawatt (MW) natural gas-fired, quick-start combined-cycle generating facility at the Salem Harbor Power Station site in Salem, Massachusetts. With duct firing under summer conditions, the facility will be capable of generating an additional 62 MW, for a total of 692 MW. Construction of the proposed Salem Harbor Redevelopment Project (SHR Project or SHR Facility) is scheduled to begin in June 2014 and continue for a period of 23 months. The SHR Facility is expected to commence commercial operations in June 2016. The existing Salem Harbor power station, which comprised four separate units as recently as 2011, was most recently owned and operated by a subsidiary of Dominion Resources, Inc. since 2005 before being acquired by an affiliate of Footprint in August 2012. Units 1 and 2, both coal-fired, were removed from service by Dominion on December 31, 2011. The two remaining units – Unit 3, a 150 MW coal-fired unit, and Unit 4, a 433 MW oil-fired unit – are scheduled to be shut down on June 1, 2014.

The proposed SHR Project will include two (2) quick-start natural gas turbine generators (GTGs); two steam turbine generators (STGs); two heat recovery steam generators (HRSGs), including pollution control equipment configured as two (2) "1 on 1" power blocks along with balance of plant facilities including an ammonia storage tank; two to three water tanks; and air-cooled condensers (ACCs). A general location map is provided in Figure 1-1.

Footprint is applying for a Comprehensive Plan Approval (CPA) from the Massachusetts Department of Environmental Protection (MassDEP) for the SHR Facility. The CPA is required under 310 CMR 7.02 and this document along with accompanying MassDEP forms and other appended material is the application for the CPA which if granted will include approval under Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21) and Nonattainment New Source Review (NNSR) (310 CMR 7.00: Appendix A).

This application consists of the following eight sections in addition to this Introduction:

- Section 2 contains a project description, including information regarding the plant's location and equipment design information;
- Section 3 provides a description of emissions and the calculation basis;
- Section 4 contains a review of Federal and State air quality regulations applicable to the SHR Project;
- Section 5 provides a demonstration of Best Available Control Technology and Lowest Achievable Emission Rate for the Project;
- Sections 6 and 7 present the ambient air quality impact analyses for the Project including dispersion modeling demonstrating compliance with state and national ambient air quality standards and PSD increments (Section 6) and additional impacts such as air quality related values including visibility, growth and impacts to soils and vegetation (Section 7);
- Section 8 provides additional information related to requirements for NNSR including emissions offsets; and
- Section 9 contains the noise analysis.
- Appendices A through I provide the CPA Forms, emission calculations, detailed equipment and vendor data, project drawings, operation and maintenance plans, air dispersion modeling files, evaluation of worst-case ammonia release, noise monitoring and modeling data, and a discussion of environmental justice.

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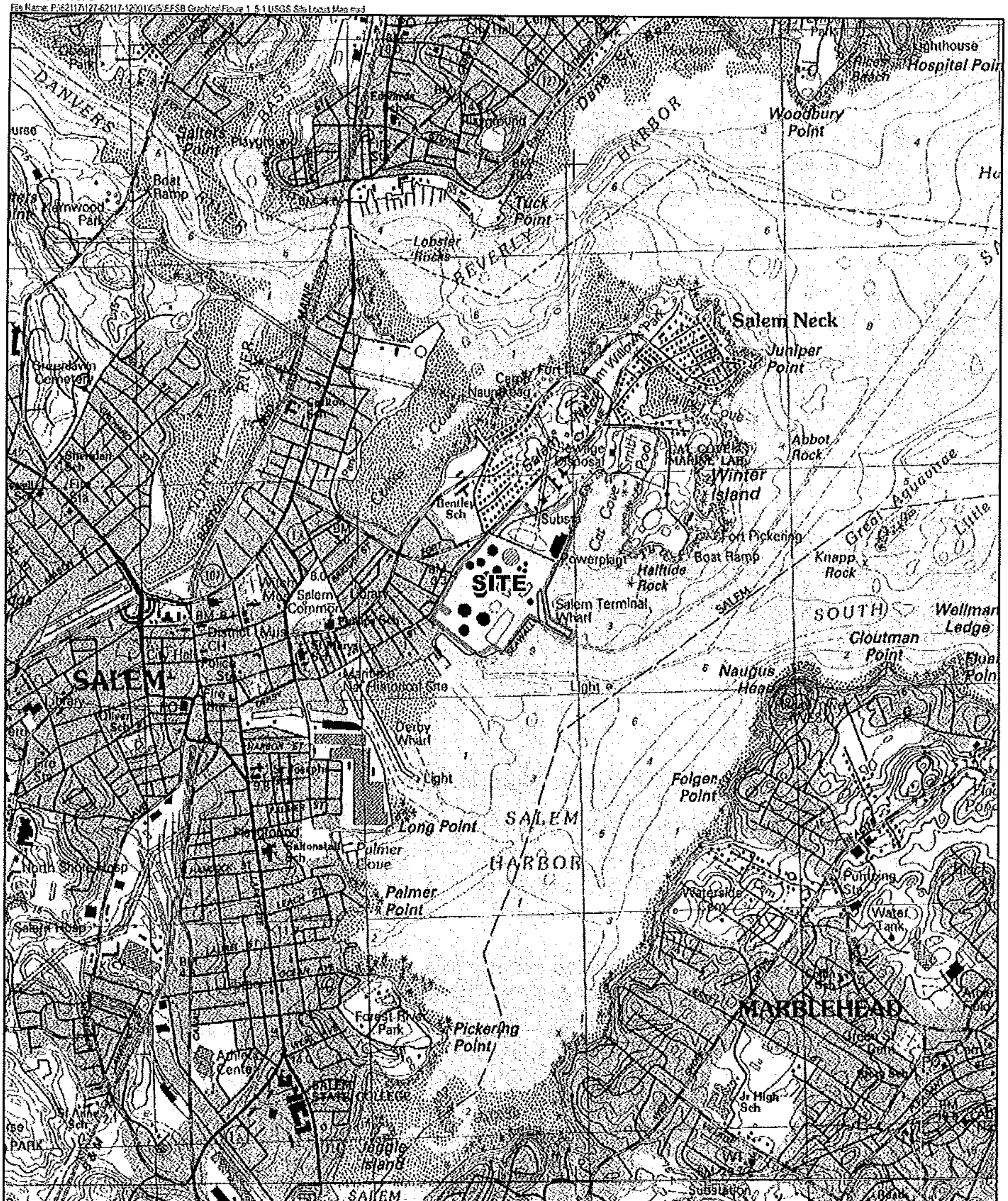

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Salem Harbor Station Redevelopment Project
Salem, Massachusetts

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0 1,000 2,000
Feet

Base Map:
USGS Topo

General Location Map Figure 1-1

2.0 PROJECT DESCRIPTION

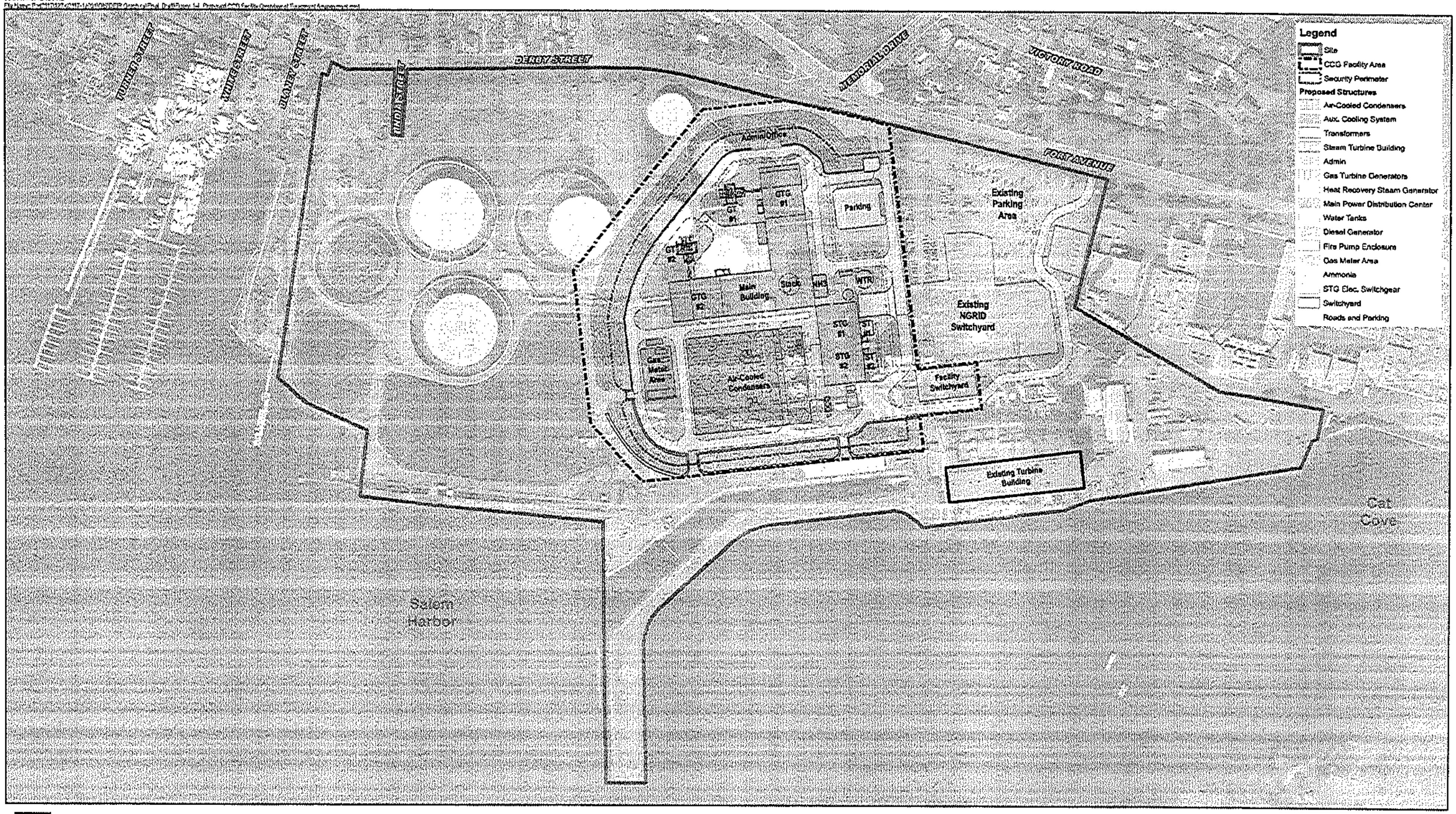
2.1 Location

The proposed SHR Facility will be constructed on +/- 20 acres in the northwestern portion of the +/- 65-acre Salem Harbor site. The 65-acre site is bordered by Fort Avenue and the South Essex Sewerage District (SESD) wastewater treatment plant to the north; Salem Harbor and Cat Cove to the east and northeast; the Blaney Street Ferry terminal and several mixed-use buildings to the southeast; and by Derby Street and Fort Avenue to the west. Residential neighborhoods and the Bentley Elementary School are located to the west across Fort Avenue and Derby Street. Terrain elevations rise gradually to the north, west, and southwest, with elevations rising 200 feet or more within approximately 10 kilometers. The site vicinity is depicted in Figure 1-1.

2.2 Facility Description

The proposed nominal 630 MW quick-start, combined-cycle natural gas-fired SHR The SHR Facility will be configured as two operating units. Each unit will be able to operate independently to respond to dispatch requirements. Most of the SHR Facility's equipment will be housed in a building structure that will be approximately 115,000 square feet (sf). The SHR Facility will include a variety of power plant equipment including: two gas turbine generators (GTGs); two steam turbine generators (STGs); two heat recovery steam generators (HRSGs) with selective catalytic reduction (SCR) and oxidation catalyst pollution control equipment; generator step-up transformers; an ammonia storage tank; water tanks; and air cooled condensers (ACCs). In addition, the SHR Facility will include areas within other buildings for administrative and operating staff; warehousing of parts and consumables; and maintenance shops and equipment servicing. All day-to-day operations of the SHR Facility will be contained within the buildings or conducted behind screening to minimize visual impacts. An overview of this equipment arrangement of the proposed SHR Facility is provided as Figure 2-1, and a detailed drawing showing equipment arrangement is provided as Figure 2-2. Heights of the buildings and ACC are presented in the dispersion modeling discussion contained in Section 6.

Each unit of the proposed SHR Facility will be a combined-cycle power plant. The first stage in the generation process will be the operation of a GTG set. Thermal energy will be produced in the GTGs through the combustion of natural gas, which will be converted into mechanical energy required to drive the turbine compressor section as well as the generator. Each gas turbine will have the capability to generate in excess of 200 MWe under all environmental conditions using natural gas. The exhaust temperature of the gas turbine is in excess of 1000 degrees Fahrenheit (1,000 °F), which represents significant heat energy. This heat energy will be recovered in a three pressure level HRSG to produce steam. This steam will be directed to a STG where this heat energy will be converted to electrical energy representing approximately 40% of the total energy generated by each unit. Efficiency is enhanced in the cycle by using reheat systems as well as using waste steam to heat feedwater in the HRSG, thereby further improving the overall efficiency. Once the steam leaves the steam turbine, it is condensed back to water using an ACC. This water is then returned to the HRSGs through a system of pumps and control mechanisms. Additional steam may be generated when required by the use of special burners within the HRSGs to increase the electricity produced by the STGs.



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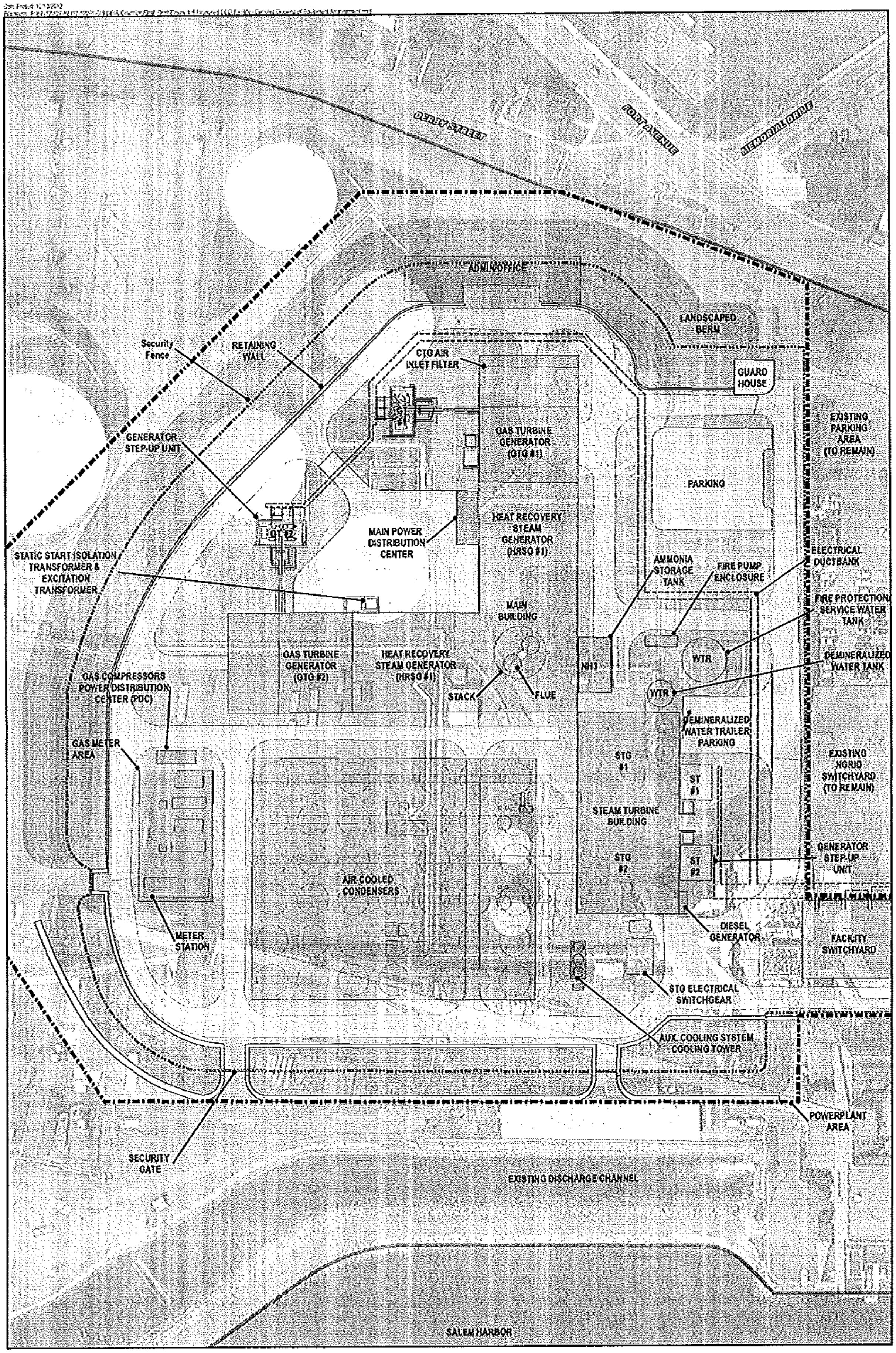
Salem Harbor Station Redevelopment Project
Salem, Massachusetts

Proposed SHR Facility
Overview of Equipment Arrangement

Figure 2-1



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Base Map:Bing 2010 Aerial

Salem Harbor Station Redevelopment Project
Salem, Massachusetts

Proposed SHR Facility
Detailed Drawing of
Equipment Arrangement

Figure 2-2

Footprint is presently considering either the Siemens FlexPlant30 SCC6-5000F(5) or the GE Energy 107FA.05 Rapid Response Combined Cycle Plant.[1] Either the Siemens or GE based power blocks can each produce approximately 150 MW (300 MW total for the plant) of output within 10 minutes of startup using both operating units together and, as such, can provide an economic, low emissions backup for intermittent wind generation.

Continuous emissions monitors (CEMS) will sample, analyze and record flue gas flow rates, nitrogen oxides (NO_x), carbon monoxide (CO) and ammonia (NH_3) concentrations levels, and the percentage of oxygen in the exhaust gas from each of the two HRSG exhaust flues. Samples also will be taken in the turbine exhaust upstream of the SCR system in order to provide data to the ammonia injection control systems. This process will generate reports of the emissions data consistent with anticipated permit requirements and will send alarm signals to plant supervisory and control systems when emissions approach or exceed limits.

Ancillary equipment at the proposed SHR Facility will include three additional fuel combustion emission units:

- An 80 million Btu per hour natural gas fired auxiliary boiler equipped with ultra low-NOx burners (Cleaver Brooks "Nebraska" D-type boiler CBND 80E-300D-65 or similar),
- A 750 KW (standby rating) emergency generator firing 15 ppm ultra low sulfur distillate (ULSD) oil (Cummins QST30-G5 NR2, Caterpillar C25-750, or similar), and
- A 371 brake horsepower (BHP) fire pump engine firing ULSD oil (Cummins CFP9E-F50 or similar)

To support the SCR system on the combined cycle units, a 34,000 gallon above-ground ammonia storage tank will be located north of the building structures. The tank itself will be constructed of steel and will contain 19% aqueous ammonia used for pollution control processes. The tank will have a diameter of 12 feet and a height of approximately 40 feet. It will have single wall construction, and along with the ammonia transfer pumps, valves and piping, will be located within a concrete containment structure (dike). In order to further mitigate the potential impacts of an accidental ammonia release, the entire tank and diked area will be located within another enclosure. The walls of the structure will be fully sealed, and the only ventilation for the structure will be by means of roof vents.

The proposed SHR Facility will interconnect with the National Grid transmission system at two locations within the existing National Grid switchyard located on the Salem Harbor site. One unit of the proposed SHR Facility units will interconnect at the same location where Salem Harbor Unit 4 facility presently is connected. The other unit will interconnect at a new circuit breaker bay to be constructed within the existing National Grid switchyard. ISO-NE has done a study that shows a need to reconductor National Grid's N158N and 158S lines and a possible need to change out breakers at the National Grid Wakefield Junction substation for increased short circuit duty capability. Footprint Power is not aware of any upgrades National Grid may be considering for its Salem Harbor Substation other than those related to the SHR Facility.

[1] Bids have been solicited, and are expected to be received, from other manufacturers as well. If selected, those manufacturers' offerings will provide the same level of benefits with the same characteristics as the representative offerings of GE and Siemens presented herein.

Natural gas will be delivered to the site via a new 16-inch pipeline owned and operated by Algonquin Gas Transmission, a subsidiary of Spectra Energy ("Spectra"),.[2] Spectra also will construct an on-site metering and regulator station. Spectra will obtain all federal, state and local approvals, as necessary. In order to interconnect with the new Spectra pipeline and on-site metering and compression station, Footprint will construct a piping system using welded steel piping designed to safely supply natural gas fuel to the gas turbines and to other auxiliary uses. The high pressure portion of the system will be installed underground, transitioning to above ground connections for each of the gas turbine generator fuel control valves and to pressure reducing stations for the auxiliary uses. These auxiliary uses will include the HRSG duct burners and the auxiliary steam boiler.

[2] The pressure, capacity and route of the new pipeline are still being developed by Spectra.

3.0 AIR EMISSIONS

This section presents short-term and long-term potential emissions from the proposed equipment for the SHR Project. Facility emissions will be controlled to BACT/LAER levels. Footprint proposes to use dry low-NO_x combustion and SCR to minimize NO_x emissions from the combustion turbines. Combustion controls and an oxidation catalyst will be used to minimize CO and volatile organic compounds (VOC) emissions from the turbines. Sulfur dioxide (SO_2) and particulate matter (PM) will be controlled through the use of the cleanest fuels available – the facility will use only natural gas as fuel for the turbines and auxiliary boiler, and ULSD oil for the emergency generator and fire pump engine. Section 5 of this application contains a detailed control technology analysis. Appendix B of this application contains detailed emission calculations and Appendix C contains equipment specifications and vendor performance data for the proposed emission sources.

3.1 Short-Term Emissions

The potential air emission sources for the project include:

- Two combined cycle power generation units, each consisting of one combustion turbine and duct burner, serving an associated HRSG and steam turbine generator, and equipped with evaporative cooling, SCR for control of NOx, and an oxidation catalyst for control of CO and VOC (Siemens SCC6-5000F(5) or GE Energy 107FA.05 or similar);
- One natural gas fired auxiliary boiler rated at approximately 80 MMBtu/hour heat input, equipped with ultra low-NOx burners (Cleaver Brooks "Nebraska" D-type boiler CBND 80E-300D-65 or similar);
- One emergency generator rated at approximately 750 kW (standby rating), firing ULSD oil (Cummins QST30-G5 NR2 or similar);
- One fire pump engine rated at approximately 371 BHP, firing ULSD oil (Cummins CFP9E-F50 or similar); and
- One three-cell auxiliary cooling tower rated at 13,000 gpm total water flow (Marley model NC8412VAN3 or similar).

The following equipment will not have any potential air emissions under normal operation:

- Two air cooled condensers (ACCs) each serving one of the combined cycle units; and
- One 34,000 gallon aboveground aqueous ammonia storage tank (see Appendix G of this application for analysis of an accidental ammonia release).

The facility will also include miscellaneous insignificant sources such as fuel oil and lubricant storage tanks, for which emissions have not been considered.

3.1.1 Combustion Turbine and HRSG Units

Short-term potential emission rates for each combined cycle unit, including the combustion turbine and associated duct burner, are presented in Table 3-1. The rates shown are based on 100% load operation at 90 °F, with duct burner firing and evaporative cooling, and represent the worst case between the two potential turbine vendors. Potential emission rates are presented in: parts per million by volume, dry basis (ppmvd), corrected to 15% O_2; pounds per million British thermal units (lb/MMBtu) on a high heating value (HHV) basis; and pounds per hour (lb/hr). The guaranteed ppmvd concentrations for NO_x, CO, VOC, and NH_3 are identical for both the Siemens and GE units. SO_2 emissions are based on a maximum natural gas sulfur content of 0.5 grains per 100 standard cubic feet (gr/100 scf). Emission rates in lb/hr differ slightly due to different heat rates for the combustion turbine and duct burner between the two vendors. Again, the worst-case emission rates are shown.

Table 3-1 Short-Term Emission Rates for Turbine and HRSG Units

Pollutant	ppmvd at 15% O_2	lb/MMBtu	lb/hr (per CTG+HRSG)
NO_X	2.0	0.0074	18.1
CO	2.0	0.0045	11.0
VOC, unfired	1.0	0.0013	3.2
VOC, duct-fired	2.0	0.0026	6.4
SO_2	0.3	0.0015	3.7
PM	N/A	<0.009	16.1
PM_{10}	N/A	<0.009	16.1
$PM_{2.5}$	N/A	<0.009	16.1
NH_3	2.0	0.0027	6.6

3.1.2 Ancillary Equipment

Short-term potential emission rates for the auxiliary boiler, the emergency generator, and the fire pump engine are presented in Table 3-2. Potential emission rates are presented in lb/MMBtu or g/kWh as appropriate, and in lb/hr.

Table 3-2 Short-Term Emission Rates for Ancillary Equipment

Pollutant	Auxiliary Boiler		Emergency Generator		Fire Pump		Aux. Cooling Tower
	lb/MMBtu	lb/hr	g/kWh	lb/hr	g/kWh	lb/hr	lb/hr
NO_X	0.011	0.88	6.4	11.6	4.0	2.4	0
CO	0.035	2.8	3.5	6.4	3.5	2.1	0
VOC	0.005	0.40	1.3	2.4	1.3	0.79	0
SO_2	0.0015	0.12	0.0015 lb/MMBtu	0.011	0.0015 lb/MMBtu	0.004	0
PM	0.005	0.40	0.232	0.42	0.232	0.14	0.10
PM_{10}	0.005	0.40	0.232	0.42	0.232	0.14	0.10
$PM_{2.5}$	0.005	0.40	0.232	0.42	0.232	0.14	0.04

3.1.3 Long-Term Emissions

The proposed annual potential emissions from the SHR Facility are summarized in Table 3-3. Annual potential emissions are based on the worst case of either the Siemens or GE turbines under consideration and are based on the following assumptions:

- For the combustion turbines, 8,040 hours at 100% load, operating at 50 °F, with no duct burner firing, and 720 hours at 100% load, operating at 90 °F, with duct burner firing and evaporative cooling (except for CO and VOC, as described below);
- For the auxiliary boiler, 6,570 hours at 100% load (full load equivalent);
- For the emergency generator and fire pump engine, 300 hours each at the maximum rated power output;
- The ACC will have no particulate emissions; and
- The auxiliary cooling tower will operate 8,760 hours at full capacity.

Table 3-3 Facility-Wide Annual Potential Emissions

Pollutant	CT Unit 1 (tpy)	CT Unit 2 (tpy)	Auxiliary Boiler (tpy)	Emergency Generator (tpy)	Fire Pump (tpy)	Auxiliary Cooling Tower (tpy)	Facility Total (tpy)
NO_x	76.8	76.8	2.9	1.7	0.4	0	158.6
CO	101.8	101.8	9.2	1.0	0.3	0	214.1
VOC	18.9	18.9	1.3	0.35	0.12	0	39.6
SO_2	15.6	15.6	0.4	0.0017	0.0006	0	31.5
PM	54.0	54.0	1.3	0.06	0.02	0.43	109.9
PM_{10}	54.0	54.0	1.3	0.06	0.02	0.43	109.9
$PM_{2.5}$	54.0	54.0	1.3	0.06	0.02	0.17	109.6
NH_3	28.0	28.0	0	0	0	0	56.0
H_2SO_4 mist	10.4	10.4	0.03	0.00013	0.00005	0	20.8
Lead	0	0	0.00013	0.000001	0.0000003	0	0.00013
Formaldehyde	3.6	3.6	0.019	0.00009	0.0005	0	7.3
Total HAP	6.9	6.9	0.5	0.0018	0.0016	0	14.3
CO_2	1,233,952	1,233,952	31,247	180	66	0	2,499,397
CO_2e	1,235,142	1,235,142	31,277	181	66	0	2,501,808

The combustion turbines have higher hourly mass emissions of CO and VOC during startup and shutdown than during full-load operation. Therefore, the annual potential emissions of CO and VOC in Table 3-3 are based on a simulated operating year that includes a conservative number of startup and shutdown cycles. Table 3-4 below presents the operating scenario used to calculate annual potential emissions for CO and VOC. The number of operating hours and startup/shutdown cycles shown are per combustion turbine.

The worst-case CO and VOC total mass emissions per complete cycle of one startup and one shutdown event are presented in Table 3-5 below. The emissions shown are per combustion turbine.

Table 3-4 Combustion Turbine Operating Scenario for Annual CO and VOC Emissions

Season	Conditions	Annual Hours at Full Load	Annual Cold Startup/ Shutdown Cycles	Annual Warm Startup/ Shutdown Cycles	Annual Hot Startup/ Shutdown Cycles
Spring/Fall	100% load at 50 °F, no evaporative cooling, no duct burner	1,200	20	80	0
Summer	100% load at 90 °F, no evaporative cooling, no duct burner	376	0	54	0
Summer	100% load at 90 °F with evaporative cooling and duct burner	720	0	0	0
Winter	100% load at 20 °F, no evaporative cooling, no duct burner	976	10	32	0
N/A	Planned outage	N/A	6	0	0
N/A	Unplanned outage	N/A	0	0	4
Annual Totals		3,272	36	166	4

Table 3-5 Total CO and VOC Mass Emissions Per Combustion Turbine Startup/Shutdown

Pollutant	Cold Startup + Shutdown (lbs)	Warm Startup + Shutdown (lbs)	Hot Startup + Shutdown (lbs)
CO	1,021	790	780
VOC	143	121	97

3.2 Hazardous Air Pollutant and Massachusetts Air Toxics Emissions

Short-term emission rates and potential annual emissions are presented in Table 3-6 for hazardous air pollutants (HAP), as promulgated by EPA under the Clean Air Act Amendments (CAAA) of 1990; and for Massachusetts "air toxics" compounds, as promulgated by the MassDEP. See Section 6 of this application for an analysis of potential ambient air impacts for Massachusetts air toxics emissions from the proposed SHR Facility.

Table 3-6 HAP and Massachusetts Air Toxics Potential Emissions

Pollutant	HAP?	AAL/TEL?	Emission Factor (lb/MMBtu)				Max. Total tpy
			CT1 CT2	Aux. Blr.	Em. Gen.	Fire Pump	
Organic Compounds							
Acetaldehyde	Y	Y	4.0E-05		2.52E-05	7.67E-04	0.8
Acrolein	Y	N	6.4E-06		7.88E-06	9.25E-05	0.1
Benzene	Y	Y	1.2E-05	2.1E-06	7.76E-04	9.33E-04	0.3
1,3-Butadiene	Y	Y	4.3E-07			3.91E-05	8.9E-03
Dichlorobenzene	Y	Y		1.2E-06			3.1E-04

Pollutant	HAP?	AAL/TEL?	Emission Factor (lb/MMBtu)				Max. Total tpy
			CT1 CT2	Aux. Blr.	Em. Gen.	Fire Pump	
Ethylbenzene	Y	Y	3.2E-05				0.7
Formaldehyde	Y	Y	3.5E-04	7.4E-05	7.89E-05	1.18E-03	7.3
Hexane	Y	N		1.8E-03			0.5
Propylene oxide	Y	Y	2.9E-05		3.85E-03	3.56E-03	0.6
Toluene	Y	Y	1.3E-04	3.3E-06	2.81E-04	4.09E-04	2.7
Xylene	Y	Y	6.4E-05		1.93E-04	2.85E-04	1.3
PAH							
Acenaphthene	Y	N		1.8E-09	4.68E-06	1.42E-06	6.2E-06
Acenaphthylene	Y	N		2.4E-09	9.23E-06	5.06E-05	3.1E-05
Anthracene	Y	N		1.8E-09	1.23E-06	1.87E-06	2.6E-06
Benzo(a)anthracene	Y	N		1.8E-09	6.22E-07	1.68E-06	1.8E-06
Benzo(a)pyrene	Y	N		1.2E-09	2.57E-07	1.88E-07	6.7E-07
Benzo(b)fluoranthene	Y	N		1.8E-09	1.11E-06	9.91E-08	1.7E-06
Benzo(g,h,i)perylene	Y	N		1.2E-09	5.56E-07	4.89E-07	1.1E-06
Benzo(k)fluoranthene	Y	N		1.8E-09	2.18E-07	1.55E-07	7.7E-07
Chrysene	Y	N		1.8E-09	1.53E-06	3.53E-07	2.3E-06
Dibenz(a,h)anthracene	Y	N		1.2E-09	3.46E-07	5.83E-07	9.3E-07
7,12-Dimethylbenz(a) anthracene	Y	N		1.6E-08			4.1E-06
Fluoranthene	Y	N		2.9E-09	4.03E-06	7.61E-06	8.3E-06
Fluorene	Y	N		2.7E-09	1.28E-05	2.92E-05	2.7E-05
Indeno(1,2,3-cd)pyrene	Y	N		1.8E-09	4.14E-07	3.75E-07	1.1E-06
3-Methylchloranthrene	Y	N		1.8E-09			4.6E-07
2-Methylnaphthalene	Y	Y		2.4E-08			6.2E-06
Naphthalene	Y	Y	1.3E-06	6.2E-07	1.30E-04	8.48E-05	2.7E-02
Phenanthrene	Y	N		1.7E-08	4.08E-05	2.94E-05	6.2E-05
Pyrene	Y	N		4.9E-09	3.71E-06	4.78E-06	7.3E-06
TOTAL PAH	Y	N	2.2E-06	6.8E-07	2.12E-04	1.68E-04	4.6E-02
Metals/Inorganics							
Ammonia	N	Y	0.0027				55.9
Arsenic	Y	Y		2.0E-07	4.62E-08	4.62E-08	5.2E-05
Beryllium	Y	Y		1.2E-08			3.1E-06
Cadmium	Y	Y		1.1E-06	5.13E-09	5.13E-09	2.8E-04
Chromium	Y	Y		1.4E-06	1.24E-05	1.24E-05	3.8E-04
Chromium VI	Y	Y		2.5E-07	2.24E-06	2.24E-06	1.4E-09

Pollutant	HAP?	AAL/TEL?	Emission Factor (lb/MMBtu)				Max. Total tpy
			CT1 CT2	Aux. Blr.	Em. Gen.	Fire Pump	
Cobalt	Y	N		8.2E-08			2.2E-05
Copper	N	Y		8.3E-07			2.2E-04
Lead	Y	Y		4.9E-07	7.69E-07	7.69E-07	1.3E-04
Manganese	Y	N		3.7E-07	2.82E-07	2.82E-07	9.8E-05
Mercury	Y	Y		2.5E-07	1.03E-08	1.03E-08	6.7E-05
Nickel	Y	Y		2.1E-06	1.48E-06	1.48E-06	5.4E-04
Selenium	Y	Y		2.4E-08	2.56E-07	2.56E-07	6.6E-06
Sulfuric Acid	N	Y	0.001	0.00012	0.00012	0.00012	20.8
Vanadium	N	Y		2.3E-06			5.9E-04
Maximum single HAP, facility-wide tpy							**7.3**
Total for all HAP, facility-wide tpy							**14.3**

Notes:

1. Blank entry (shaded) indicates no emission factor reported in the reference cited.
2. Emission factors for CT1 and CT2 are from Table 3.1-3 of AP-42 except for formaldehyde which is based on expected performance for new lean pre-mix combustion turbines. H_2SO_4 is based on 67% of SO_2 emissions (mass basis).
3. Emission factors for the auxiliary boiler are from AP-42 Tables 1.4-3 and 1.4-4.
4. Emission factors for organics the emergency diesel generator and fire pump are from AP-42 Tables 3.4-3 and 3.4-4 for the emergency generator and Table 3.3-2 for the fire pump.
5. Metal emissions for the emergency generator and fire pump are based on the paper "*Survey of Ultra-Trace Metals in Gas Turbine Fuels*", 11th Annual International Petroleum Conference, Oct 12-15, 2004. Where trace metals were detected in any of 13 samples, the average result is used. Where no metals were detected in any of 13 samples, the detection limit is used.
6. Hexavalent chrome for the aux boiler, emergency generator and fire pump are based on 18% of the total chrome emissions based on EPA 453/R-98-004a).
7. H_2SO_4 emissions for aux boiler, emergency generator and fire pump are based on 8% of SO_2 emissions (mass basis).

4.0 REGULATORY REVIEW AND APPLICABILITY

The United States Environmental Protection Agency (EPA) and MassDEP have promulgated regulations that establish ambient air quality standards and emission limits for sources of air pollution. This section of the application identifies the regulations that may apply to the proposed SHR Facility and discusses how Footprint will meet any applicable requirements.

The federal regulations reviewed here include: (1) National Ambient Air Quality Standards (NAAQS); (2) Prevention of Significant Deterioration (PSD) and New Source Review (NSR) requirements; (3) New Source Performance Standard (NSPS); (4) National Emission Standards for Hazardous Air Pollutants (NESHAP); (5) the Acid Rain Program; (6) the Title V Operating Permit Program; and (7) the Clean Air Interstate Rule (CAIR) / Cross State Air Pollution Rule (CSAPR).

In Massachusetts, compliance with these regulatory requirements is implemented through the MassDEP Air Plan Approval process, promulgated at 310 CMR 7.02. The air pollution regulations contained in 310 CMR 7.00 and its associated appendices include a number of state-only requirements applicable to the proposed SHR Facility, which are also identified and discussed below.

4.1 National Ambient Air Quality Standards

The EPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are sulfur dioxide (SO_2), particulate matter, nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), and lead (Pb). The MassDEP also has adopted these limits as Massachusetts Ambient Air Quality Standards (MAAQS).

The NAAQS have been developed for various averaging times. "Short-term" NAAQS, those that apply to averaging times of 24 hours or less, refer to pollutant levels that cannot be exceeded except for a limited number of cases per year. "Long-term" NAAQS are annual averages. The NAAQS include both "primary" and "secondary" standards. The Clean Air Act requires that the primary standards be set to protect human health allowing an adequate margin of safety and the secondary standards be set to protect the public welfare from any known or anticipated adverse effects associated with the presence of air pollutants in the ambient air.

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

In areas designated as nonattainment for a particular pollutant, the air quality with respect to the pollutant is worse than the NAAQS. These areas must take actions to improve air quality and attain the NAAQS within a certain period of time.

If a new major source of air pollution is proposed, it must undergo New Source Review (NSR). There are two NSR programs, one for sources being built in attainment/unclassifiable areas, and one for sources in nonattainment areas. The NSR program for sources in attainment/unclassifiable areas is known as the

PSD Program. The NSR program for sources being built in non-attainment areas is known as Nonattainment NSR or NNSR.

The site is presently classified as "attainment" for SO_2, NO_2, and "attainment/ unclassifiable" (combined definition) for ozone, CO, lead and all particulates. Thus, emissions of these pollutants are evaluated under the PSD program.

To identify new pollution sources with the potential to significantly alter ambient air quality, the EPA and MassDEP have adopted significant impact levels ("SILs") for the criteria pollutants. Proponents of new major sources (or major modifications of existing major sources) are required to perform a dispersion modeling analysis to predict air quality impacts of the new source in comparison to the SILs. If the predicted impacts of the new or modified source are less than the SIL for a particular pollutant and averaging period, then the impacts are considered "insignificant" for that pollutant and averaging period. However, if the predicted impacts of the new or modified source are greater than the SIL for a particular pollutant and averaging period, then further impact evaluation is required. This further evaluation must include measured background levels of pollutants, and emissions from both the proposed new source and existing interactive sources.

As is demonstrated in Table 4-1 and Section 6 of this application, with the exception of $PM_{2.5}$ (24-hour and annual concentrations), PM_{10} (24-hour average concentrations), and NO_2 (1-hour average and annual concentrations), the predicted concentrations of criteria pollutants from the SHR Facility are expected to be less than the SILs. Therefore, the background air quality and interactive source evaluation is required only for particulates and NO_2.

Table 4-1 National and Massachusetts Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS/MAAQS (μg/m³)		Significant Impact Level (μg/m³)	Maximum Predicted SHR Project Impact
		Primary	Secondary		
NO_2	Annual[1]	100	Same	1	0.7
	1-hour[2]	188	None	7.5	54.3
SO_2	Annual[1, 3]	80	None	1	0.06
	24-hour[3, 4]	365	None	5	1.1
	3-hour[4]	None	1,300	25	1.6
	1-hour[5, 6]	196	None	7.8	1.4
$PM_{2.5}$	Annual[7]	12	Same	0.3	0.5
	24-hour[8]	35	Same	1.2	4.9
PM_{10}	24-hour[9]	150	Same	5	5.8
CO	8-hour[4]	10,000	None	500	279
	1-hour[4]	40,000	None	2,000	393
O_3	8-hr[10]	147	Same	NA	NA
Pb	3-month[1]	0.15	Same	NA	<0.00016

1 Not to be exceeded.
2 Compliance based on 3-year average of the 98th percentile of the daily maximum 1-hour average at each monitor within an area.
3 The 24-hour and annual average primary standards for SO_2 will be revoked.
4 Not to be exceeded more than once per year.
5 Compliance based on 3-hear average of 99th percentile of the daily maximum 1-hour average at each monitor within an area.
6 The 1-hour SO_2 standard was effective as of August 23, 2010.
7 Compliance based on 3-year average of weighted annual mean $PM_{2.5}$ concentrations at community-oriented monitors.
8 Compliance based on 3-year average of 98th percentile of 24-hour concentrations at each population-oriented monitor within an area.
9 Not to be exceeded more than once per year on average over 3 years.
10 Compliance based on 3-year average of fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area.

4.2 Prevention of Significant Deterioration Review

The PSD Air Quality Program is a federally-mandated program review of major new sources of criteria pollutants designed to maintain the NAAQS and prevent degradation of air quality in attainment/unclassifiable areas. The PSD program, which is now implemented by the MassDEP, applies to new major sources and major modifications of existing sources of air pollution.

For PSD purposes, a combustion turbine combined-cycle generation facility is considered a major source if emissions of any criteria pollutant are greater than 100 tons/year or if emissions of greenhouse gases ("GHG") expressed as carbon dioxide (CO_2) equivalent (or CO_2e) are greater than 100,000 tons per year. The SHR Facility will have potential emissions greater than 100 tons/year for one or more attainment criteria pollutants and potential emissions greater than 100,000 tons/year of CO_2e. Therefore, the proposed facility will be a major PSD source.

For a major PSD source, PSD regulations also apply to each criteria pollutant that is emitted in excess of a defined significant emission rate. Table 4-2 presents a PSD major source threshold analysis for the SHR Facility for those pollutants with applicable PSD emission criteria. As shown in Table 4-2, the facility is subject to PSD review for particulates (PM), NO_x, CO, sulfuric acid mist (H_2SO_4), and GHGs. (See Section 3.2 for the assumptions used in determining annual potential emissions.)

Table 4-2 Prevention of Significant Deterioration Regulatory Threshold Evaluation

Pollutant	Project Annual Emissions (tons)	PSD Major Source Threshold (tons)	PSD Significant Emission Rate (tons)	PSD Review Applies
CO	214.1	100	100	Yes
NO_x	158.6	100	40	Yes
SO_2	31.5	100	40	No
PM	109.9	100	25	Yes
PM_{10}	109.9	100	15	Yes
$PM_{2.5}$	109.5	100	10	Yes
VOC (ozone precursor)	39.6	100	40	No
Lead	0.00013	100	0.6	No
Fluorides	Negligible.	100	3	No
Sulfuric Acid Mist	20.8	100	7	Yes
Hydrogen Sulfide (H_2S)	none expected	100	10	No
Total Reduced Sulfur (including H_2S)	none expected	100	10	No
Reduced Sulfur Compounds (including H_2S)	none expected	100	10	No
GHGs (as CO_{2e})	2,501,808	100,000	75,000	Yes

The key requirements for obtaining a PSD permit are a demonstration of Best Available Control Technology (BACT), and a demonstration of compliance with the NAAQS and PSD increments. Section 5 of this application presents a detailed control technology analysis demonstrating how the SHR Facility will achieve BACT under EPA and MassDEP requirements. As set out in the air quality impact analysis in Section 6 of this application, the SHR Facility will comply with NAAQS and will have emissions well below the PSD increments.

4.3 Nonattainment New Source Review

If a major source of pollution is proposed in an area designated as nonattainment for a particular pollutant, the source is subject to NNSR for that pollutant. The federal Clean Air Act defines levels of nonattainment classifications for O_3. Until recently, the entire Commonwealth of Massachusetts was classified as moderate nonattainment for 8-hour O_3, but now most of the state is considered by the EPA to be unclassifiable/attainment. However, MassDEP has not taken any action to revise its Non-Attainment NSR provisions as a result of the recent reclassification of most of the state to "unclassifiable/attainment" for 8-hr O_3. Therefore, the provisions of MassDEP regulations at 310 CMR 7.00: Appendix A is still currently applicable to major sources of NO_x and VOC, as precursors to ozone.

For purposes of Non-Attainment NSR in Massachusetts, a source is considered a major source of NO_x and VOC if the emissions of these pollutants exceed 50 tons/year.

As shown in Table 4-2, above, the SHR Facility will be a major source of NO_x, but will not be a major source of VOC. Consequently, the facility is subject to NNSR requirements with respect to NO_x only. Under these requirements, the facility must achieve the Lowest Achievable Emission Rate for NO_x, and procure NO_x emissions offsets. LAER is the emission rate that reflects: (1) the most stringent emissions limitation included in the implementation plan of any state for a similar source unless the source proponent demonstrates such limitations are not achievable; or (2) the most stringent emissions limitation achieved in practice, whichever is more stringent. The facility will achieve LAER by combusting only natural gas and by using dry low-NO_x combustion and SCR. See Section 5 for a detailed control technology analysis.

Offsets for NO_x are required at a minimum ratio of 1.2:1 in all areas of Massachusetts as specified in 310 CMR 7.00 Appendix A. The MassDEP requires an additional 5% of offsets, bringing the effective minimum ratio to 1.26:1. Thus, 200 tpy of NO_x offsets are required for the SHR Facility (158.6 tpy times 1.26 = 199.8 tpy). Footprint Power will have the required NO_x offsets prior to commercial operation of the SHR Facility. See Section 8 for more details on emission offsets.

4.4 New Source Performance Standards

The EPA has established New Source Performance Standards at 40 CFR Part 60 that regulate air pollutant emissions from certain categories of stationary sources. For combustion sources, emission standards typically are expressed in terms of mass emissions per unit of fuel combusted, fuel quality, or exhaust gas concentration. Sources subject to a specific NSPS category are also subject to the general rules in 40 CFR 60, Subpart A. The following NSPS categories are applicable to emission units included in the SHR Facility:

- Stationary Combustion Turbines (40 CFR 60, Subpart KKKK);
- Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc); and
- Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII).

Subpart KKKK

Subpart KKKK applies to stationary combustion turbines with a heat input rating greater than or equal to 10 MMBtu/hr, which commenced construction, reconstruction, or modification after February 18, 2005.

Subpart KKKK also applies to emissions from any associated HRSGs or duct burners, and therefore includes both the combustion turbines and the supplementary gas-fired duct burners at the SHR Facility.

The NSPS applicable to the combined cycle units, which include both the, are set forth at 40 CFR 60 Subpart KKKK. The NSPS for NO_x allow the turbine owner or operator the choice of a concentration-based or output-based emission standard. The concentration-based limit is expressed in units of parts per million by volume, dry basis (ppmvd) at 15 percent oxygen. The output-based emission limit is expressed in units of emissions mass per unit of useful recovered energy, nanograms per Joule (ng/J), or pounds per megawatt-hour (lb/MWh).

The applicable NO_x standard for the SHR Facility is 15 ppmvd at 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh). At 2 ppmvd, emissions of NO_x from the combined cycle generating units will be well below the NSPS.

The NSPS for SO_2 are the same for all turbines regardless of size or fuel type. The standard for turbines located in a continental area prohibits the discharge into the atmosphere of any gases that contain SO_2 in excess of 110 ng/J (0.90 lb/MWh) gross energy output. The owner of a turbine can choose to comply either with the SO_2 limit itself or with a limit on the sulfur content of the fuel. For a turbine located in a continental area, the fuel sulfur content limit is 26 ng/J (0.060 lb SO_2/MMBtu) heat input.

The SHR Facility will meet the NSPS for SO_2 by using natural gas with a sulfur content not exceeding 0.5 grains sulfur/100 cubic feet of gas-fired (less than 0.01 percent sulfur by weight or 0.0015 lbs SO_2/MMBtu), well below the NSPS limit.

Subpart Dc

The SHR Facility will include a natural gas-fired auxiliary boiler to provide steam during plant startup. Based on the design rating for the auxiliary boiler of 80 MMBtu/hour, this unit will be subject to the NSPS under 40 CFR 60, Subpart Dc, which applies to steam generating units for which construction, reconstruction, or modification is commenced after June 9, 1989, and that have a heat input rating between 10 and 100 MMBtu/hr. For natural gas-fired boilers, Subpart Dc only requires initial notification and does not impose specific emission limits.

Subpart IIII

The emergency generator and fire pump engines will both be subject to the NSPS under 40 CFR 60, Subpart IIII. Subpart IIII requires emergency generators to meet the non-road engine emission standards identified in 40 CFR 89.112 and 89.113. The fire pump will be subject to the emission standards identified in 40 CFR 60, Subpart IIII, Table 4. Subpart IIII requires manufacturers to produce engines that comply with these standards. Footprint will purchase emergency generator and fire pump engines that comply with Subpart IIII.

4.5 National Emission Standards for Hazardous Air Pollutants

The NESHAPs, codified in 40 CFR Parts 61 and 63, regulate hazardous air pollutant (HAP) emissions. Part 61 was promulgated prior to the 1990 CAAA and regulates only eight types of hazardous substances (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride). The proposed SHR Facility is not in one of the source categories regulated by Part 61; therefore, the requirements of Part 61 are not applicable.

The 1990 CAAA established a list of 189 HAPs, resulting in the promulgation of Part 63. Part 63, also known as the Maximum Achievable Control Technology (MACT) standards, regulates HAP emissions from both major sources of HAP emissions and non-major (area) sources of HAP emissions within specific source categories. Part 63 defines a major source of HAP as any source that has the potential to emit 10 tpy of any single HAP or 25 tpy of all HAPs in aggregate. As shown in Table 3.2-1, the SHR Facility will be a non-major or area source of HAP.

Potentially applicable NESHAPs exist for owners and operators of the following stationary source types included in the SHR Facility:

- Stationary Combustion Turbines (40 CFR 63, Subpart YYYY)
- Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR 63, Subpart UUUUU)
- Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD)
- Industrial, Commercial, and Institutional Boilers Area Sources (40 CFR 63, Subpart JJJJJ)
- Stationary Reciprocating Internal Combustion Engines (40 CFR 63, Subpart ZZZZ)

Subpart YYYY, applicable to stationary combustion turbines, was promulgated on March 5, 2004. However, in April 2004, EPA proposed to "delist" natural gas-fired combustion turbines from the NESHAP program. In August 2004, EPA stayed (indefinitely) the combustion turbine NESHAP for natural gas-fired turbines (including any unit which fires oil less than 1,000 hours per year) pending a final decision on delisting. Therefore, there are no NESHAPs applicable to the SHR Project combustion turbines.

The supplementary-fired duct burners that will be located in the combustion turbine exhaust fall under a different NESHAP category from the turbines, and are considered to be electric utility steam generating units. Subpart UUUUU, applicable to coal- and oil-fired electric utility steam generating units, was promulgated on February 16, 2012. However, Subpart UUUUU does not regulate natural gas-fired units. Therefore, there are no NESHAP requirements applicable to the duct burners, which will be strictly gas-fired.

Subpart DDDDD, for industrial, commercial and institutional boilers, applies only to major sources of HAP. The SHR Facility will not be a major source of HAP, and the auxiliary boiler is therefore not subject to Subpart DDDDD.

Subpart JJJJJ is applicable to industrial, commercial and institutional boilers at area (or minor) HAP sources, but does not include gas-fired units. Therefore, there are no NESHAP requirements applicable to the auxiliary boiler.

Subpart ZZZZ applies to stationary reciprocating internal combustion engines (RICE) at both major and non-major sources of HAP. Both the emergency generator and the fire pump engine will be subject to Subpart ZZZZ. However, for new emergency units, the NESHAP requirements are satisfied if the units comply with the NSPS under 40 CFR 60, Subpart IIII. As stated above, Footprint will purchase emergency generator and fire pump engines that comply with NSPS Subpart IIII.

4.6 Federal Acid Rain Program

New utility units are subject to the federal Acid Rain Program under 40 CFR 72. A new utility unit, as defined under 40 CFR Part 72.6, is a fossil-fuel fired combustion device that commences operation after

November 15, 1990 and that serves a generator producing electricity for sale. The two combined cycle units at the SHR Facility will be subject to the Acid Rain Program, and must have an Acid Rain permit application submitted to the permitting authority at least 24 months prior to commencement of operation. Pursuant to 40 CFR Part 72.21, 40 CFR Part 72.73, and 310 CMR 7.00: Appendix C(3)(n), MassDEP is the permitting authority for Phase II Acid Rain Permits.

Prior to submitting an Acid Rain permit application, the SHR Facility will select an authorized representative and submit a completed certificate of representation form to EPA as required under 40 CFR Part 72.20.

Affected sources must create a compliance plan stating they will hold sufficient SO_2 allowances by the allowance transfer deadline to account for SO_2 emissions for each calendar year.

4.7 Continuous Emission Monitoring

Affected units subject to federal Acid Rain Program emission limits for SO_2 or NO_x are also subject to the continuous emission monitoring requirements set forth at 40 CFR Part 75. The requirements of 40 CFR 75 will apply to the combined cycle combustion turbines and duct burners, and include detailed requirements for monitoring, recordkeeping, and reporting of emissions. Affected units must install and operate a continuous emission monitoring system (CEMS) for NO_x, SO_2, CO_2, and opacity, and must prepare maintain a monitoring plan, as provided at 40 CFR Part 75.53, describing the methodologies used to monitor and report emissions. 40 CFR 75 also includes detailed specifications and test procedures, and quality assurance and quality control procedures, for ensuring proper collection of valid CEMS data.

Footprint will comply with the monitoring, recordkeeping, and reporting requirements of 40 CFR 75.

4.8 Title V Operating Permit

Massachusetts has been delegated authority by EPA to administer the federal Title V operating permit program (40 CFR 70) under its regulations at 310 CMR 7.00: Appendix C. Facilities are subject to the requirements of 310 CMR 7.00: Appendix C if they meet any of the following conditions:

- Have potential emissions of VOC or NOx exceeding 50 tpy;
- Are subject to a NESHAP standard;
- Are subject to NSPS; or,
- Include an affected source under the federal Acid Rain Program.

The SHR Facility is subject to both NSPS and the federal Acid Rain Program, and has potential NO_x emissions exceeding 50 tpy, and is therefore subject to the Title V operating permit program under 310 CMR 7.00: Appendix C. Subject facilities are required to submit an operating permit application to MassDEP no later than one year after commencement of operation. Footprint will submit an operating permit application within the required timeframe.

4.9 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) requirements under 40 CFR Part 64 apply to any emission unit located at a major source required to obtain a Title V operating permit, if that unit:

- Is subject to an emission limit or standard for a regulated pollutant;

- Uses a control device to achieve compliance with that limit or standard; and
- Has uncontrolled potential emissions of that regulated pollutant in excess of the major source threshold.

The combined cycle turbines and duct burners meet these criteria for emissions of NO_x and CO. However, CAM does not apply to NSPS or MACT standards proposed by EPA since November 15, 1990, and also does not apply if the Title V Operating Permit specifies a continuous compliance determination method. Since the facility will be equipped with a continuous emission monitoring system (CEMS) for NO_x and CO and this will be specified in the Title V Operating Permit, it is exempt from CAM requirements.

4.10 Clean Air Interstate Rule

CAIR is a market-based regulatory program (similar to the Acid Rain Program and NO_x Budget Program) implemented by the EPA to control emissions of precursors of ozone and fine particulates. The MassDEP implements CAIR pursuant to its regulations at 310 CMR 7.32, in which allowances are allocated to all existing sources at an equal rate and prorated to historic power generation output. Although EPA replaced the CAIR program with the Cross State Air Pollution Rule (CSAPR) in August 2011, Massachusetts did not change its regulation because it was not one of the states subject to CSAPR (in addition, CSAPR was vacated by the D.C. Circuit Court of Appeals on August 12, 2012).

Under CAIR, Massachusetts emission sources such as fossil-fueled power plants need to hold or procure sufficient "allowances" to cover actual NO_x emissions. An "allowance" is the authorization to emit one (1) ton of NO_x during the ozone season (May – September) each year.

There is a set-aside program for new sources such as the SHR Facility. This allocation method is similar to earlier NO_x Budget Program rules. It is expected that new clean units such as the SHR Facility will receive allowances sufficient to enable base load operation. Footprint will monitor facility NO_x emissions and comply with all CAIR monitoring and reporting requirements.

4.11 Federal Greenhouse Gas Reporting

EPA regulations at 40 CFR Part 98 require activities in certain source categories to report emissions of the greenhouse gases CO_2, NH_4, and N_2O. 40 CFR 98, Subpart D applies to electric generating units that are subject to the federal Acid Rain Program or that are required to report CO_2 emissions year-round under 40 CFR 75. The combined cycle combustion turbines and associated duct burners will be regulated under Subpart D, which specifies that CO_2 emissions will be monitored as required under 40 CFR 75, and converted to metric tons for reporting under 40 CFR 98.

Subpart C of 40 CFR 98 applies to fuel combustion sources with a combined heat input capacity of 30 MMBtu/hr or greater at facilities emitting at least 25,000 metric tons of CO_2e per year, except that electric generating units under Subpart D, and emergency equipment as defined under 40 CFR Part 98.6, are not subject to Subpart C.

Emissions of CH_4 and N_2O from the combined cycle units will be calculated using the appropriate equations for combustion sources in Subpart C of 40 CFR 98. The auxiliary boiler is not an electric generating unit, and will be regulated under Subpart C, as it is expected that actual facility-wide emissions of CO_2e will exceed 25,000 metric tons per year. Emissions of CO_2, CH_4, and N_2O from the auxiliary boiler will be calculated using the appropriate equations in Subpart C of 40 CFR 98. The emergency generator and fire pump engine are exempt from the requirements of 40 CFR 98.

4.12 Chemical Accident Prevention Provisions

Section 112(r) of the Clean Air Act and associated EPA regulations at 40 CFR 68 applies to owners or operators of stationary sources producing, processing, handling or storing toxic or flammable substances. The substances regulated under section 112(r) and their threshold quantities are listed at section 68.130 of 40 CFR 68.

Although the SHR Facility will not store regulated substances above the threshold quantities, the general duty clause in 112(r)(1) still applies:

> "The owners and operators of stationary sources producing, processing, handling or storing [hazardous] substances have a general duty in the same manner and to the same extent as section 654, title 29 of the United States Code, to identify hazards which may result from [accidental] releases using appropriate hazard assessment techniques, to design and maintain a safe facility taking such steps as are necessary to prevent releases, and to minimize the consequences of accidental releases which do occur."

The SHR Facility will take steps necessary to meet the general duty provisions above. See Appendix G of this application for an analysis of a worst-case accidental ammonia release.

4.13 Massachusetts Requirements

General Regulations to Prevent Air Pollution

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

Comprehensive Plan Approval

Regulation 310 CMR 7.02 establishes the requirement for a plan approval to be issued prior to the construction, reconstruction, alteration, or operation of a facility that may emit contaminants to the ambient air. The proposed SHR Facility exceeds several of the thresholds requiring submittal of a Comprehensive Plan Approval (CPA) application, set forth at 310 CMR 7.02(5)(a). Among these thresholds, the proposed SHR Facility will increase potential emissions of an air contaminant by 10 tpy or more, will include multiple fuel combustion units rated at 40 MMBtu/hr or greater, and will be subject to both PSD regulations under 40 CFR 52.21 and Emissions Offsets and Nonattainment Review under 310 CMR 7.00: Appendix A.

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

- Completed MassDEP CPA application forms;
- A description of the proposed SHR Facility, including site plans, drawings, and detailed emission calculations (operating and maintenance procedures will be provided after final equipment vendors have been selected);

- A demonstration of compliance, as required under 310 CMR 7.02(8)(a), with the most stringent applicable emission limits of LAER, BACT, NSPS, NESHAP, and MACT; and
- Air dispersion modeling demonstrating compliance with NAAQS and MAAQS.

Particulate Standards

Regulation 310 CMR 7.02(8)(h) limits particulate emissions from fuel burning sources to 0.10 lb/MMBtu for new fossil fuel combustion facilities with heat input capacities of 3 to 250 MMBtu/hr, and to 0.05 lb/MMBtu for new fossil fuel combustion facilities with heat input capacities greater than 250 MMBtu/hr. All subject combustion sources at the SHR Facility are expected to comply with these limits. The combined cycle units, including the combustion turbines and associated duct burners, will achieve particulate emissions of 0.009 lb/MMBtu or less, while the auxiliary boiler will achieve particulate emissions of 0.005 lb/MMBtu. The emergency generator and emergency fire pump engine will meet applicable particulate emission limits under 310 CMR 7.26(42).

Sulfur in Fuel Standard

Regulation 310 CMR 7.05 establishes fuel sulfur content and ash content limits for fossil fuel combustion facilities located in Massachusetts. This regulation generally applies to liquid fossil fuels. 310 CMR 7.05(1)(a), which was amended on July 20, 2012, establishes several stepped limits for sulfur content in distillate oil, which is limited to 0.3% by weight prior to July 1, 2014; to 0.05% by weight from July 1, 2014 through June 30, 2018; and to 0.0015% by weight on and after July 1, 2018. Natural gas has only trace quantities of sulfur and ash, well below any established fuel content limits for liquid fuels. The emergency generator and fire pump engines will be the only oil-fired emission sources at the SHR Facility, and will comply with the fuel sulfur requirements of 310 CMR 7.05 by burning only distillate oil containing no more than 0.0015% sulfur by weight.

Visible Emissions

Regulation 310 CMR 7.06(1)(b) states that no emissions of non-water vapor visible emissions (opacity) from fuel burning equipment shall exceed 20 percent opacity for a period in excess of two minutes during any one hour, provided that at no time during that two-minute period shall the opacity exceed 40 percent. All fuel-burning equipment at the SHR Facility will comply with this standard.

Dust, Odor, Construction and Demolition

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

Footprint will comply with the notification and work practice requirements of 310 CMR 7.09. Specific measures expected to be taken during demolition of the existing structures at the proposed SHR Facility site include:

- Pre-cleaning of large surfaces and structural members to remove large concentrations of dusting materials prior to demolition;
- Water suppression sprays and misting of potential dust-creating situations to prevent spreading of airborne particulates; and
- Enclosure of areas with tarps and screening when necessary to prevent the migration of dust.

Specific measures expected to be taken during construction of the new structures include:

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

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

Noise

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

The proposed SHR Facility will comply with the requirements of 310 CMR 7.10. Footprint will employ a number of sound mitigation measures to minimize operational noise. See Section 9 for a detailed analysis of existing baseline noise levels and projected impacts from operation of the facility.

Source Registration

The owner or operator of any facility exceeding the applicability thresholds at 310 CMR 7.12 must submit a source registration to MassDEP. Facilities must submit a source registration annually if they are required to obtain an operating permit under 310 CMR 7.00: Appendix A, or if their actual emissions of NO_x or VOC are equal to or greater than 25 tpy. Since the SHR Facility will exceed these thresholds, the SHR Facility will be required to submit annually, and the source registration must include, among other things, a description of the facility's process and combustion equipment, operating schedule, actual fuel and raw material consumption, and estimates of actual emissions for all regulated air pollutants at the facility. Footprint will comply with the requirement to submit annual source registrations.

Stack Testing

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

Footprint will comply with the requirements of 310 CMR 7.13. The combined cycle combustion turbines and associated duct burners are required to conduct performance testing under the federal NSPS requirements of 40 CFR 60. Provisions for stack testing of the other air emission sources will be made as deemed necessary by MassDEP.

Monitoring Devices and Reports

Regulation 310 CMR 7.14 requires air emission sources, upon request by MassDEP, to install, maintain and operate emission monitoring devices of a design and installation approved by MassDEP, and to submit periodic emission reports to MassDEP. The combined cycle combustion turbines and associated duct burners are required to install and operate a CEMS under the provisions of 40 CFR Parts 60 and 75. Footprint will provide CEMS design and installation information to MassDEP once a final equipment vendor has been selected. Monitoring devices for other emission sources at the proposed SHR Facility will be installed and operated if requested by MassDEP.

NO_x RACT

Regulation 310 CMR 7.19 establishes Reasonably Available Control Technology (RACT) for sources with uncontrolled potential emissions of NO_x greater than or equal to 50 tpy. RACT is the application of control technology that is reasonably available and results in the lowest emission limit that is both technologically and economically feasible for a particular source. The requirements of 310 CMR 7.19 do not apply to sources that obtain a plan approval under 310 CMR 7.02 that establishes BACT or LAER to be no less stringent than RACT as defined in 310 CMR 7.19 at the time of plan approval.

The requirements of 310 CMR 7.19 do not apply to emergency engines that operate no more than 300 hours per year.

Massachusetts Clean Air Interstate Rule

Regulation 310 CMR 7.32 implements the Clean Air Interstate Rule (CAIR) in Massachusetts, which regulates emissions of NO_x during the annual ozone season (May through September of each year) and requires affected sources to hold sufficient NO_x allowances to cover actual emissions. See Section 4.10 for further discussion of the CAIR program requirements.

Massachusetts CO_2 Budget Trading Program

Regulation 310 CMR 7.70 establishes the Massachusetts CO_2 Budget Trading Program, which requires electric generating units equal to or greater than 25 MW to hold sufficient CO_2 allowances to cover actual emissions. Affected sources must submit an emission control plan and a monitoring plan for CO_2 emissions. In general, emission units required to monitor CO_2 emissions in accordance with 40 CFR 75 or 310 CMR 7.32 will meet the monitoring requirements of 310 CMR 7.70. 310 CMR 7.70 also establishes a system for allocating CO_2 allowances to affected sources, and for tracking CO_2 allowances held. Affected sources must designate an authorized account representative, and emission control plans must be submitted to MassDEP at least 12 months before the date an affected source commences operation.

Footprint will comply with the requirements of 310 CMR 7.70.

Massachusetts Greenhouse Gas Reporting

Massachusetts has established a GHG reporting and verification program under 310 CMR 7.71. This regulation applies to facilities that are required to report air emissions to MassDEP under the operating permit program at 310 CMR 7.00: Appendix C and had stationary emission sources that emitted GHGs during the previous calendar year; or that have actual emissions in excess of 5,000 short tons per year (tpy) of CO_2e; or that were subject to the requirements of 310 CMR 7.71 in any previous year. The SHR Facility is expected to become subject to 310 CMR 7.71 after its first year of operation, and will report GHG emissions as required.

Emission Offsets and Nonattainment Review

Regulation 310 CMR 7.00: Appendix A sets forth preconstruction review requirements for new sources located in an area designated as nonattainment for any NAAQS pollutant, which would be a major emission source for that pollutant. Although the proposed SHR Facility is located in an attainment area for ozone, the MassDEP has not revised its regulations to reflect that. As such, the SHR Facility will be required to obtain emission offsets for NO_x, of which it will be a major source. See Section 4.3 of this application for further discussion of the nonattainment new source review program. See Section 8 of this application for further discussion of the required NO_x emission offsets.

5.0 CONTROL TECHNOLOGY ANALYSIS

This section presents the LAER and BACT analyses for the proposed SHR Facility. In accordance with 310 CMR 7.02, the Project is subject to BACT for all pollutants. The Project will also exceed PSD significant emission thresholds for NO_x, CO, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG, and thus is subject to BACT under this program. Since potential NO_x emissions will also exceed the major source threshold of 50 tons per year under nonattainment new source review (310 CMR 7.00 Appendix A), the Project is also subject to the more stringent LAER requirements for NO_x and compliance with LAER requirements will satisfy BACT requirements for NO_x.

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

The MassDEP requires a "top-down" approach to 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 an alternative, starting with the most stringent, is eliminated based on these criteria, the next most stringent technology is evaluated until BACT is selected.

The following control technology analysis encompasses both combustion turbine models currently under consideration for the Project. Section 5.1 addresses the control technology assessments for the combustion turbines. Section 5.2 addresses the control technology assessments for the auxiliary boiler and Section 5.3 addresses the assessments for the emergency generator and fire pump engines. The control technology analyses for each pollutant have been conducted in accordance with EPA "top down" BACT guidance and MassDEP guidance (June 2011) and precedent.

5.1 Combined Cycle Combustion Turbines

5.1.1 Lowest Achievable Emission Rate Analysis for NO_x

As stated previously, the SHR Project is a major new source of NO_x emissions under Appendix A of 310 CMR 7.00 and the Project is therefore subject to LAER controls for NO_x.

In accordance with MassDEP regulations, LAER is defined as "the more stringent rate of emissions based on the following:

- The most stringent emissions limitation which is contained in any state SIP for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or

- The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within a stationary source."

Sources Reviewed & Selection of LAER

When determining LAER for a particular project, the initial steps are much the same as a "top down" BACT analysis. In a "top-down" BACT analysis, all possible control technologies are identified and ranked from the top level of control to the bottom and evaluated based upon several criteria. However, in a LAER analysis only the top level of control is considered.

In order to identify the "most stringent emissions limitation which is achieved in practice" by an "F" Class combined cycle combustion turbine facility, numerous sources of information were evaluated. These sources included both state and federal resources of publicly available air permitting information. States that contain significant areas that are non-attainment for ozone, including California, New York, New Jersey, Connecticut, and Massachusetts were the focus for state specific determinations and guidance. The following sources of information were evaluated to determine LAER:

- EPA's RACT, BACT, LAER Clearinghouse (RBLC);
- MassDEP's BACT Guidance of June 2011 including Top Case BACT Guidelines for Combustion Sources;
- EPA Region IV's National Combustion Turbine List;
- The California Air Resources Board (CARB) BACT Clearinghouse;
- The California South Coast Air Quality Management District's (SCAQMD) BACT guidelines;
- State environmental program websites;
- New Jersey's State Of The Art (SOTA) Manual for Stationary Combustion Turbines; and
- The California Energy Commission Energy Facilities Siting Board.

In addition to these sources of information, additional publicly available information obtained through Tetra Tech's experience, such as permits for individual projects not listed in the RBLC or other sources, was also included in the analysis.

Reduction in NO_x emissions can be achieved using combustion controls and/or flue gas treatment. Available combustion controls include dry low-NO_x (DLN) combustors that can be employed during either water or steam injection. The most common post combustion flue gas treatment for combustion turbines is selective catalytic reduction (SCR). Recent combustion turbine projects with a generating capacity of greater than 100 MW have been permitted to utilize SCR to achieve the permitted NO_x emission levels. Accordingly, the Project is proposing to use state of the art DLN combustors in combination with SCR to control NO_x emissions. This combination of controls provides the top level of NO_x emission control for large combustion turbine projects and represents LAER.

DLN combustors are designed to minimize NO_x emissions from the combustion turbine. SCR is placed in the exhaust of the combustion turbine to further lower emissions. SCR reduces NO_x to nitrogen (N_2) and water (H_2O) in the presence of a catalyst and ammonia.

An SCR system is composed of an ammonia storage tank, ammonia forwarding pumps and controls, an injection grid (a system of nozzles that spray ammonia into the exhaust gas ductwork), a catalyst reactor, and instrumentation and controls. The injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water in the catalyst reactor.

Several different types of catalysts can be used to accommodate a wide range of flue gas temperatures. Base metal catalysts, typically containing vanadium and/or titanium oxides, are typically used between 450°F and 800 °F. Combined cycle combustion turbine projects employ a heat recovery steam generator (HRSG) to produce steam from the hot exhaust gases in order to generate additional electricity in a steam turbine. As a result, combined cycle projects can design the HRSG such that a base metal SCR catalyst can be placed within the HRSG under its optimum temperature window to maximize NO_x reduction.

Based on review of all available data, SCR has been determined to control NO_x emissions down to the lowest possible emission rates. SCR is a reliable control technology with a long track record on "F" Class combustion turbines. No other control technology has successfully been used to achieve low NO_x emissions on large combustion turbines. The LAER emission limit is proposed to be 2.0 ppm corrected to 15% O_2 based on MassDEP's Top Case BACT values for large combustion turbines.

5.1.2 Best Available Control Technology Assessment for Volatile Organic Compounds

Volatile Organic Compounds VOC are emitted from combustion turbines as a result of incomplete oxidation of the fuel. VOC emissions from combustion turbines can be minimized by the use of proper combustor design and good combustion practices. Depending upon the species of VOCs in the turbine exhaust, an oxidation catalyst may further reduce emissions. An oxidation catalyst is a passive reactor that consists of a honeycomb grid of metal panels coated with a platinum catalyst that is placed in the HRSG in the exhaust gas path.

The SHR Project is proposing to incorporate an oxidation catalyst in order to implement the top level of control to achieve BACT for CO emissions (see Section 5.1.3 below). This system will also reduce VOC emissions but the amount of reduction is expected to be modestl. Nevertheless, the installation of a state of the art combustion turbine equipped with advanced combustion controls and an oxidation catalyst represents the top level of control for VOC emissions from the Project and therefore satisfies the top case for BACT. The proposed BACT emission limit for VOC is 1.0 ppmvdc (volume, dry basis, corrected to 15% O_2) without duct firing and 2.0 ppmvdc with duct firing. Duct firing is expected to occur up to a maximum of 720 hours per year The Top Case VOC BACT value in the June 2011 MassDEP Top Case BACT Guidelines is 1.7 ppmvdc. This is based on the Mystic Station Combined Cycle Project, which was approved at 1.0 ppmvdc VOC without duct firing and 1.7 ppmvdc with duct firing. While the VOC numbers for Footprint and Mystic match without duct firing, the vendor guarantee available now with duct firing is 2.0 ppmvdc. The most recent combined cycle project permitted in Massachusetts with duct firing is the Brockton Project, which was approved (in July 2011) at 1.0 ppmvdc without duct firing and 2.5 ppmvdc with duct firing. Therefore, the VOC limits proposed limit for the SHR Facility (1.0 ppmvdc without duct firing and 2.0 ppmvdc with duct firing) are considered to represent BACT.

5.1.3 Best Available Control Technology Assessment for Carbon Monoxide

CO is emitted from combustion turbines as a result of incomplete oxidation of the fuel. CO emissions can be minimized by the use of proper combustor design and good combustion practices. The most stringent CO control technology is a catalytic oxidation system. A catalytic oxidation system can provide 90% nominal reduction in CO emissions. The oxidation catalyst is a passive reactor that consists of a honeycomb grid of metal panels coated with a platinum catalyst. The catalyst grid is placed in the HRSG in the turbine exhaust gas. The Project is proposing to include an oxidation catalyst in order to achieve the top level of control for CO emissions as specified in the June 2011 MassDEP Top Case BACT Guidelines. This BACT level for CO is 2.0 ppmvdc.

5.1.4 Best Available Control Technology Assessment for PM, PM_{10}, and $PM_{2.5}$

Emissions of particulate matter result from trace quantities of ash (non-combustibles) in the fuel as well as products of incomplete combustion. Conservatively, all particulate matter (PM) emissions are presumed to be less than 2.5 microns in size ($PM_{2.5}$). Particulate emissions are minimized by utilizing state of the art combustion turbines firing natural gas since natural gas is the lowest ash-content fuel available. BACT for particulates in a combustion turbine is good combustion practices and the use of natural gas.

5.1.5 Best Available Control Technology Assessment for Sulfur Dioxide (SO_2)

Sulfur dioxide is emitted from the combustion turbines as a result of the oxidation of the sulfur in the fuel. The only practical means for controlling SO_2 emissions from a combustion turbine project is to limit the sulfur content of the fuel. The Project proposes to use natural gas as the only fuel with no oil backup. Natural gas is the lowest sulfur content fuel commercially available and therefore the top level of BACT for the Project. The sulfur content of the natural gas will be limited to 0.5 grains per 100 cubic feet of gas, or approximately 0.0015 lbs SO_2/MMBtu.

5.1.6 Best Available Control Technology Assessment for Sulfuric Acid Mist

H_2SO_4 emissions are generated by the oxidation of sulfur in the fuel. By reducing fuel sulfur content, H_2SO_4 emissions decrease. BACT for H_2SO_4 is the use of natural gas, which has inherently low sulfur content.

5.1.7 Best Available Control Technology Assessment for Ammonia (NH_3)

Ammonia emissions are due to the use of SCR for NO_x control. Ammonia is injected into the SCR in excess of stoichiometric amounts to achieve maximum conversion of NO_x. This means that slightly more ammonia is injected than is physically required to remove the NO_x in the exhaust gas if operating at 100% efficiency. Additional ammonia is required mostly to offset inefficiencies in the mixing of ammonia in the air stream and insufficient residence time for reaction of the NH_3/NO_x mixture across the catalyst. As a result, some of the injected ammonia does not react, passes through the SCR reactor, and is exhausted to the atmosphere. These ammonia emissions are called the "ammonia slip." BACT for ammonia emissions is proper operation of the SCR to minimize ammonia slip to 2.0 ppmvdc. This represents the top case for combined cycle turbines above 10 MW listed in MassDEP's BACT Guidance of June 2011.

5.1.8 Summary of Proposed Criteria Pollutant BACT/LAER Determinations

In accordance with MassDEP's BACT Guidance document dated June 2011, MassDEP has compiled emission limits that may be proposed in lieu of performing a Top-Down analysis. These are limits that MassDEP has approved recently and these limits represent BACT. With regard to natural gas-fired combined cycle combustion turbines >10 MW, the MassDEP Top Case BACT Guidelines for Combustion Sources provides the BACT emission limits listed in Table 5-1.

Table 5-1 Top Case BACT Emission Limits

Pollutant	Emission Limitation	BACT Determination	Control Technology
NO_X	2.0 ppmvd @ 15% O_2	MassDEP Top Case BACT Guidelines for Combined Cycle Turbine > 10 MW (June 2011)	• Dry Low NOx Combustor • SCR • Oxidation Catalyst
NH_3	2.0 ppmvd @ 15% O_2		
CO	2.0 ppmvd @ 15% O_2		
VOC[1]	1.0 ppmvd @ 15% O_2 without duct firing 2.0 ppmvd @ 15% O_2 with duct firing		

[1]The Top Case VOC BACT value in the MassDEP Top Case BACT Guidelines is 1.7 ppmvdc. The vendor guaranteed VOC emission rate with duct firing is 2.0 ppmvdc. MassDEP has more recently approved a similar project (Brockton) for 2.5 ppmvdc. Therefore, Footprint Power is proposing a VOC BACT emission limit of 2.0 ppmvd @ 15% O_2 with duct firing.

With the Mystic Station Redevelopment Project cited as the basis for the Top Case BACT emission limits, Footprint Power proposes lower limits than approved for Mystic Station emission limits for PM/PM_{10} and SO_2 to represent BACT for the SHR Project. The proposed emission limits compared to the Mystic limits are shown in Table 5-2 below.

Table 5-2 Mystic Station BACT Emission Limits

Pollutant	SHR Proposed Emission Limitation	Mystic Station BACT Determination Transmittal Number W004632	Control Technology
PM	≤ 0.009 lbs/MMBtu	0.011 lbs/MMBtu	• Good combustion practices • Natural gas
PM_{10}	≤ 0.009 lbs/MMBtu	0.011 lbs/MMBtu	
$PM_{2.5}$	≤ 0.009 lbs/MMBtu	0.011 lbs/MMBtu	
SO_2	0.0015 lbs/MMBtu	0.0029 lb/MMBtu [1]	
H_2SO_4	0.0010 lbs/MMBtu	0.0016 lb/MMBtu [2]	

1 Mystic Station SO_2 emission limit is 0.0029 lbs/MMBtu. However, based on the approved gas sulfur content of 0.8 grains per 100 ft^3, the equivalent SO_2 emission limit is 0.0023 lbs/MMBtu.

2 This value is not in the current Mystic Station Operating Permit, but is referenced in the original PSD Approval (January 2000).

5.1.9 Startup/Shutdown (SUSD) Emissions

Combustion turbines experience increased VOC, CO and NO_x emissions during startup and shutdown due to the non-steady state operations. In addition, low operating temperatures preclude the use of the SCR. BACT for startup and shutdown is good operating practices by following the manufacturer's recommendations during startup, and limiting the startup time. The combustion turbines proposed for the SHR Project are "quick-start" turbines, each capable of approximately 150 MW (300 MW total) within 10 minutes of startup. These quick-start turbines significantly reduce startup emissions compared to older generations which take several hours to reach maximum capacity. The selected combustion turbine will be operated in accordance with manufacturer specifications during SUSD periods in order to ensure that emissions are minimized during these short periods. Additionally, ammonia injection will be initiated as a soon as the SCR catalyst reaches the vendor specified minimum operating temperature and all system permissives are met to minimize NO_x emissions during these periods. The estimated startup/shutdown emissions are provided in Table 5-3.

Table 5-3 Startup and Shutdown Emission Limits (lbs per event)

Pollutant	Startup (duration 45 minutes)	Shutdown (duration 30 minutes)
NO_x	88	60
CO	491	530
VOC	104	46

5.1.10 Best Available Control Technology Assessment for Greenhouse Gases

Unlike guidance for the other key pollutants addressed above, MassDEP has not issued formal Top Case BACT Guidance for GHG. Therefore, EPA BACT guidance has been used for this determination. The BACT process is discussed in detail in the EPA document "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting" , which is not a rule but acts as a non-binding guidance document for EPA, state permitting authorities and permit applicants. In addition to the 1990 EPA guidance document, the BACT analysis pertaining to GHG has been conducted in accordance with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases". Although the 2011 guidance document refers to the same top-down methodology described in the 1990 document, it provides additional clarification and detail with regard to some aspects of the analysis.

Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, the applicant must identify all "available" control options which have the potential for practical application to the emission unit and regulated pollutant under evaluation, including lower-emitting process and practices. In assessing available GHG control measures, we reviewed EPA's RACT/BACT/LAER Clearinghouse, the South Coast Air Quality Management District's BACT determinations, and the Pioneer Valley Energy Center permit information found on the EPA Region 1 website (Pioneer Valley is a recently permitted 431 MW combined cycle turbine project in Westfield, Massachusetts). The only document found with pertinent GHG BACT information was the Pioneer Valley permit data. EPA stated generally that BACT for The Pioneer Valley project is energy efficient combustion technology and additional energy savings measures at the facility, if possible. Specifically, BACT was cited as installation of a combined cycle turbine and GHG emission limits were developed.

For the proposed SHR Project, potential GHG controls are:

1. low carbon-emitting fuels;
2. carbon capture and storage (CCS); and
3. energy efficiency and heat rate.

Step 2: Technical Feasibility of Potential GHG Control Options

Low Carbon-Emitting Fuels

Natural gas combustion generates significantly lower carbon dioxide emission rates per unit heat than distillate oil (approximately 27% less) or coal (approximately 50% less). Use of biofuels would reduce fossil-based carbon dioxide emissions, since biofuels are produced from recently harvested plant material rather than ancient plant material that has transformed into fossil fuel. However, biofuels are in liquid form, and the SHR Facility is not being designed for liquid fuel. In addition, combined cycle turbines have technical issues with biofuels that have yet to be resolved. It is likely that distillate fuel would need to have a limited percentage of biofuel added to be feasible. In this case, natural gas would still have lower fossil-based carbon emissions compared a distillate oil/biofuel mixture. For these reasons, biofuels have been eliminated from consideration. Therefore, natural gas represents the lowest carbon fuel available for the SHR Facility.

Energy Efficiency and Heat Rate

EPA's GHG permitting guidance states,

> "Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. EPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions...."

EPA also recommends that permit applicants "propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks...which represent a high level of performance within an industry." With regard to electric generation from combustion sources, the combined cycle combustion turbine is considered to be the most efficient technology available. Below is a discussion of energy efficiency and a comparison to other common combustion-based electric generation technologies.

GHG emissions from electricity production are primarily a function of the amount of fuel burned; therefore, a key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Another way to refer to maximizing efficiency is minimizing the heat rate. The heat rate of an electric generating unit is the amount of heat needed in BTU (British Thermal Units) to generate a kilowatt of electricity (kW), usually reported in Btu/kW-hr. The more efficient generating units have lower heat rates than less efficient units. Older, more inefficient boilers and turbines consume more fuel to generate the same amount of electricity than newer, more efficient boilers and turbines. This is due to equipment wear and tear, improved design in newer models as well as the use of higher quality metallurgy. In general, boilers have a higher heat rate than combustion turbines due to the loss of energy in the transfer of heat from combustion to the water tubes. The combustion energy in a turbine is more directly imparted on the turbine blade than a boiler. Combined cycle turbines also use the waste heat from the combustion turbines to generate additional power (utilizing the HRSG).

In addition to the efficiency of the electricity generation cycle itself, there are a number of key plant internal energy sinks (parasitic losses) that can improve a plant's net heat rate (efficiency) if reduced. Measures to increase energy efficiency are clearly technically feasible and are addressed in more detail in Step 4 of the BACT process.

Carbon Capture and Storage

With regard to CCS, as identified by US EPA, CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options). While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases.

As identified by the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and the US Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have been implemented either in non-combustion applications (i.e., separating CO_2 from field natural gas) or on relatively small-scale combustion applications (e.g., slip streams from power plants, with volumes on the order of what would correspond to one megawatt). Scaling up these existing processes represents a significant technical challenge and potential barrier to widespread commercial deployment in the near term. It is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that will need to be addressed to facility widespread, cost-effective deployment of CO_2 capture. Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant applications.

Regarding pipeline transport for CCS, there is no nearby existing CO_2 pipeline infrastructure (see Figure 5-1); the nearest CO_2 pipelines to Massachusetts are in northern Michigan and southern Mississippi. With regard to storage for CCS, the Interagency Task Force concluded that while there is currently estimated to be a large volume of potential storage sites, "to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes" and that "scale-up from a limited number of demonstration projects to widescale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)".

Based on the abovementioned EPA guidance regarding technical feasibility and the conclusions of the Interagency Task Force for the CO_2 capture component alone (let alone a detailed evaluation of the technical feasibility of right-of-ways to build a pipeline or of storage sites), CCS has been determined to not be technically feasible.

Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

Based on the results of Step 2, the only option being carried further into the analysis is the evaluation of energy efficiency and heat rate. The SHR Project is already using the lowest carbon fuel and carbon capture and storage is not currently feasible.

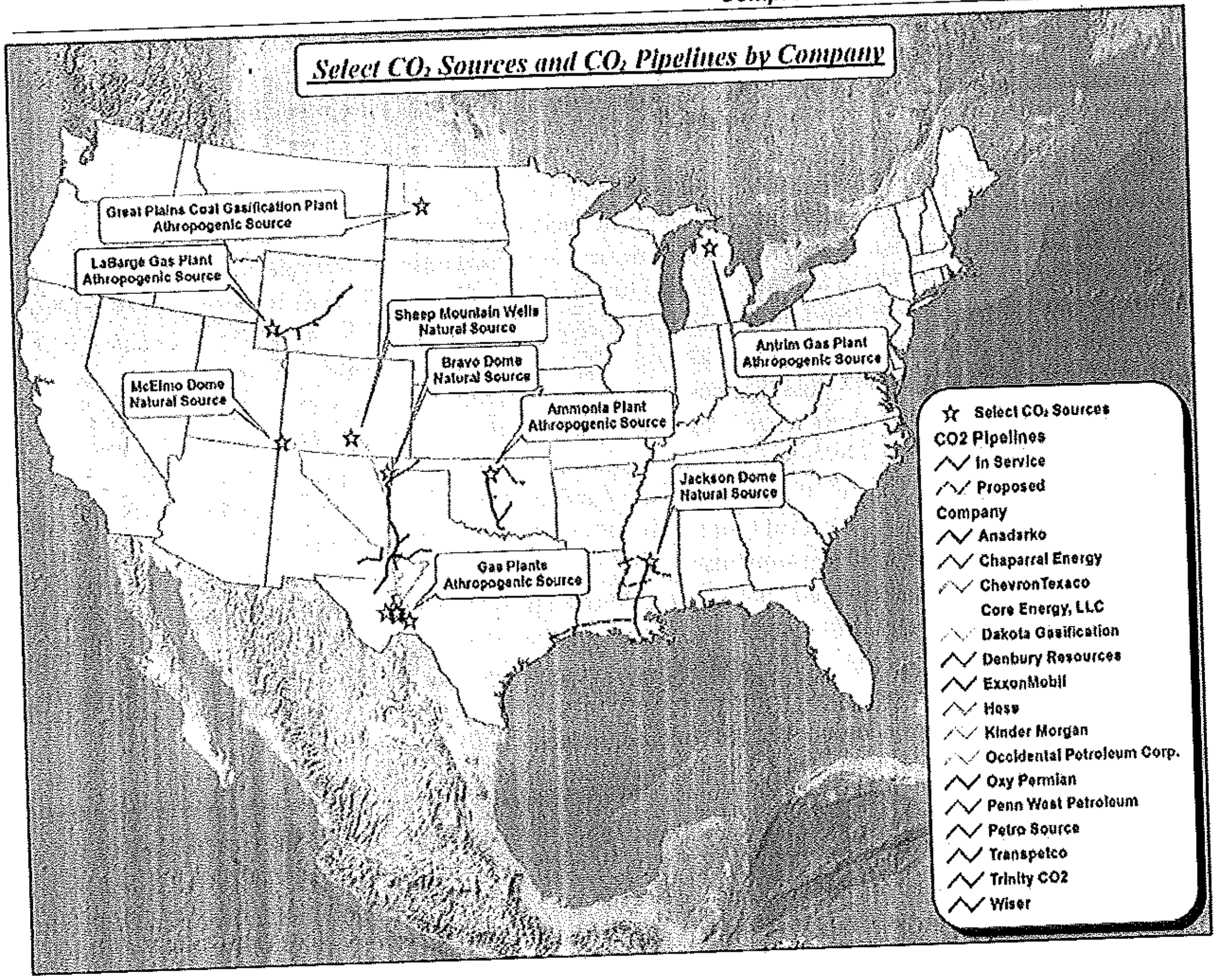


Figure 5-1 CO_2 Pipelines in the United States
From: "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, Appendix B.)

Step 4: Evaluation of Energy Efficiency and Heat Rate

Improvements to energy efficiency and "heat rate" are important GHG control measures that can be employed to mitigate GHG emissions. Heat rate indicates how efficiently power is generated by combustion of a given amount of fuel. Heat rate is normally expressed in units of British thermal units (Btu) need per net kilowatt-hour (kw-hr) of energy produced. A higher value of "heat rate" indicates more fuel (i.e., Btu) is needed to produce a given amount of energy (lower or less favorable efficiency), while a lower value of heat rate indicates less fuel (i.e., Btu) is needed to produce a given amount of energy (higher or more favorable efficiency).

The Proposed Project is using advanced combustion turbine combined cycle technology, which is recognized as the most efficient commercially available technology for producing electric power from fossil fuels. Improvements to the heat rate typically will not change the amount of fuel combusted for a given combustion turbine installation, but it will allow more power to be produced from a given amount of fuel (i.e., improve the heat rate) so that more GHG emissions will be displaced from existing sources.

Key factors addressed in the evaluation of energy efficiency and heat rate are the core efficiency of the selected turbines and the significant factors affecting overall net heat rate in combined cycle operating mode.

The design basis of the proposed project is to install approximately 630 MW of electric, generation which is equivalent to two "F" Class turbines in combined cycle configuration. "G" class turbines are slightly more efficient and thus have a lower heat rate; however, "G" class turbines generate approximately 380 to 400 MW per turbine (or 760 to 800 MW for two turbines). In addition, "G" class turbines generally have a higher low operating limit (the lowest MW output at which the facility can operate in compliance with its permits) than the proposed "F" class turbines. Although "G" class turbines are slightly more energy efficient that the proposed "F" Class turbines, "G" Class turbines would alter the scope of the project due to their size. The "F" Class design size provides the compatible size match to the existing high voltage switchyard and electrical interconnection infrastructure associated with the exiting Salem Harbor Generating Station site. The "F" class design also provides greater operational flexibility and therefore lower overall emissions. The expected heat rate or efficiency differential between "F" and "G" combined cycles, comparably configured and equipped is less than 1 percent at ISO conditions, in unfired mode, when both plants are comparably equipped for quick start-up. When site specific conditions are accounted for, this apparent efficiency difference between "F" and "G" class machines is further reduced by the higher parasitic power consumption of the fuel gas compressors for the "G" machines, which require higher natural gas supply pressures compared to "F" class. For these reasons, "G" class machines have been eliminated from consideration for the Proposed Project.

The advanced generation of "F" class machines have upgraded performance with increased MW output and improved heat rate compared to prior designs. These machines also represent the current state-of-the-art for the evolving "F" class technology that is now been in operation for greater than 20 years with thousands of machines in operation. This provides a conservative and predictable basis to formulate financial plans and to project future reliability and costs. The steam cycle portion of the plant (HRSG, piping, & steam turbine generator) as designed with two smaller units in the "1 on 1" configuration will exhibit superior operational flexibility, ability to deal with rapid thermal transients and exhibit acceptable and foreseeable long term O&M cost impacts.

With regard to energy efficiency considerations in combined cycle combustion turbine facilities, the activity with the greatest effect on overall efficiency is the method of condenser cooling. As with all steam-based electric generation, combined cycle plants can use either dry cooling or wet cooling for condenser cooling. Dry cooling uses large fans to condense steam directly inside a series of piping, similar in concept to the radiator of a car. Wet cooling can either be closed cycle evaporative cooling (using cooling towers), or "once-through" cooling using sea water.

Total fuel heat input to the combined cycle combustion turbine (fuel burned in the combustion turbines and in the HRSG duct burners) and thus total steam flow available to the steam turbine, is fixed. The efficiency of conversion of the fixed steam flow to electrical output of the steam turbine generator is then primarily a function of the backpressure at which the low pressure turbine exhausts. A wet cooling system consisting either of a mechanical draft cooling tower with circulating water pumps and a shell and tube condenser, or a once-through system directly circulating sea water to the condenser, are capable of providing significantly lower condensing pressures compared to an all dry ACC system. Wet cooling performance is superior for efficiency purposes because of the basic thermodynamics of cooling, which allows either the cooling tower or once through system to produce colder water compared to dry cooling. As a result, operation of a dry cooling system requires approximately 1-5% more energy than a wet cooling system depending on ambient conditions (difference between wet and ACC systems gets smaller with lower ambient temperatures).

However, there are significant drawbacks to either a once-through system or wet mechanical draft cooling tower system. Once-through cooling involves use of large quantities of sea water that is returned to the ocean at a higher temperature. The impingement and entrainment associated with intake of the necessary large quantities of sea water, and the thermal impacts of discharges of once-through cooling, have been recognized to have negative environmental impacts and once-through cooling has therefore been eliminated from consideration.

Wet mechanical draft cooling towers also require a significant quantity of water, most of which is lost to evaporation to the atmosphere. The most likely candidate source for the volumes required would be the SESD sewage treatment plant. User of seawater for makeup to a wet evaporative system is a very challenging application, but has been done in limited cases. It is technically feasible to use effluent from a public sewerage treatment facility as make-up to a wet, evaporative cooling system. However the presence of the typical chemical constituents of the effluent and the likely highly variable concentrations of certain of these constituents would place a burden on the CCG Facility. The effluent transferred from SESD would require further treatment to make it suitable and safe to use in the cooling system. Even after further treatment the concentrations of certain dissolved minerals in the circulating water would impact the design; most likely require a high degree of cooling tower blowdown to maintain acceptable chemistry and requiring the upgrade of the metallurgy of the piping, condenser tube, pumps and other components that would be exposed to the more corrosive action of the treated and concentrate effluent.

An additional burden imposed of wet, evaporative cooling is dealing with the creation of visible fog plume, which discharges from the cooling tower fans. With the typical New England, coastal site weather conditions, a standard mechanical draft cooling tower would produce a very visible and persistent plume for many hours of the year. It is possible to use a so-called "plume abated" mechanical draft tower. But this feature can double the cost of the cooling tower and increase the total fan power consumption and pumping head on the system. Basically the "plume abatement" feature works by using heat from the hot condenser discharge water to preheat additional ambient air admitted above the normal cooling tower wet, evaporative heat exchange zone. This hotter air has a lower relative humidity; such that as it mixes with the wet, almost saturated air discharged from the evaporative cooling surface, the combined air mixture reaches a moisture content below the saturation point. As this hotter, dryer air mixture is discharged by the tower fans it can then mix with the cool, damp ambient air without crossing the saturation line and producing small water droplets which form the visible plume.

The bottom line is that a wet, evaporative mechanical draft cooling tower with plume abatement features has a doubled capital cost, higher fan power consumption and higher pumping head than a standard cooling tower. These latter two factors greatly reduce any potential benefit from reduced parasitic load from the wet cooling system.

Therefore, Footprint has determined that the marginal heat rate improvement that could be achieved with a plume abated mechanical draft tower does not outweigh the drawback of the technical issue associated with use of the SESD sewage effluent, as well as the fact that a visible plume will still be present at times with a plume abated tower. The use of dry cooling has therefore been selected over either wet cooling option.

Step 5: GHG BACT

The very low heat rates (high efficiency) associated with the combined cycle combustion turbine technology selected for the SHR Project and the use of the lowest carbon fossil fuel, natural gas, as the exclusive fuel represent BACT for GHG for this project. Two F series turbines in combined cycle configuration have been determined integral to the project design size of 630 MW. Quick-start capability has been included to increase overall project efficiency.

Footprint Power is proposing an emission limit in lbs of CO_2/MW-hr delivered to the electrical grid (net), to be met during an initial stack test. Since weather conditions, which affect efficiency during a stack test, are unknown at this time, the proposed emission limit is based on International Organization for Standardization (ISO) conditions. ISO 3977-2 sets the standard conditions at 59°F, 14.7 psia, and 60% humidity. Weather conditions during the stack test will be corrected to these ISO values.

Using a maximum design net "new and clean" heat rate at ISO conditions of approximately 7080 Btu/kw-hr_{grid} (based on fuel higher heating value) and a CO_2 emission factor of 118.9 lbs/million Btu provides a "new and clean" GHG emission rate of 842 lbs CO_2/MW-hr_{grid}. Footprint Power believes that CO_2 is a valid surrogate for GHG since greater than 99.9% of all GHG emissions on a CO_2e basis are CO_2. Footprint Power proposes a "new and clean" emission limit of 842 lbs CO_2/MW-hr_{grid}. Since a turbine's efficiency will degrade with time and fluctuate due to ambient conditions, the emission limit of 842 lbs CO_2/MW-hr_{grid} should apply only during the initial stack test. This test would be done at base load conditions.

5.2 Auxiliary Boiler

The SHR Project will include the installation of an 80 MMBtu/hr heat input, natural gas-fired auxiliary boiler. Annual operation of the auxiliary boiler will be limited to the full load equivalent of 6,570 hrs/yr. The unit will be equipped with ultra-low NO_x burners for NO_x control. Emissions will be controlled through the exclusive use of natural gas as fuel, good combustion practices and a limit on the annual operations. In addition, the auxiliary boiler will meet the emission limits determined by MassDEP to be the Top Case BACT for natural gas fired boiler between 40 MMBtu and 100 MMBtu/hr in size (June 2011) with the exception of PM/PM_{10}/$PM_{2.5}$. The top BACT case listed in the June 2011 MassDEP guidance for natural gas boilers of this size is 0.002 lb/MMBtu which Footprint Power does not believe is feasible as BACT for this application. For PM/PM_{10}/$PM_{2.5}$ Footprint Power is proposing a BACT limit of 0.005 lb/MMBtu.. This BACT limit is more stringent than other recent BACT limits for natural gas fired boilers in Massachusetts. PM BACT limits established relatively recently for auxiliary boilers at Mystic Station and Veolia MATEP are 0.007 lb/MMBtu and for Brockton Power is 0.01 lb/MMBtu. The PM BACT limit for the auxiliary boiler at Pioneer Valley Energy Center is comparable at 0.0048 lb/MMBtu.

The Top Case BACT emission limits for the Auxiliary Boiler are shown in Table 5-8.

Table 5-8 Top Case BACT Emission Limits for the Auxiliary Boiler

Pollutant	Emission Limitation	BACT Determination	Control Technology
NOx	0.011 lbs/MMBtu	MassDEP Top Case BACT Guidelines for Natural Gas Boilers (40-100 MMBtu/hr heat input) (June 2011)	• Ultra Low NOx Burners (9 ppm) • Good combustion practices • Natural gas
$PM/PM_{10}/PM_{2.5}$ [1]	0.005 lbs/MMBtu		
CO	0.035 lbs/MMBtu		
VOC	0.005 lbs/MMBtu		
SO_2 [2]	0.0015 lbs/MMBtu	Plan Approval, Transmittal Number W004632	Natural Gas
H_2SO_4 [3]	0.0010 lbs/MMBtu	2	Natural Gas

1 Top Case BACT for natural gas-fired boilers between 40 and 100 MMBtu/hr in the MassDEP guidance (June 2011) is 0.002 lbs PM/MMBtu.. Footprint Power is proposing a PM/PM10/PM2.5 emission limit of 0.005 lbs PM/MMBtu which is comparable or less than MassDEP values recently approved for new gas-fired boilers.

2 Mystic Station auxiliary boiler SO_2 emission limit is 0.0023 lbs/MMBtu. Based on the gas sulfur content of 0.5 grains per 100 ft^3, the proposed SO_2 emission limit is 0.0015 lbs/MMBtu.

3 Assumed to be equivalent to 2/3 of SO_2 emissions based on vendor data. No H_2SO_4 emission limit cited in Mystic Station air permit.

5.3 Emergency Generator and Fire Pump Engines

The Project will include an emergency diesel generator (EDG) engine and a diesel fire pump (FP). Both engines will operate on Ultra Low Sulfur Diesel (ULSD) fuel. The proposed EDG will be a Cummins 750DQFAA ULSD-fired engine (or equivalent) with a standby generating capacity of 750 kW. The FP engine will be a 371 BHP, 2.7 MMBtu/hr ULSD-fired engine. Both engines will be used in emergency situations only (with the exception periodic maintenance/testing events) and will be limited to a maximum of 300 hours per rolling 12 month period of operation. There are no post-combustion controls that have been demonstrated in practice for small, emergency internal combustion engines. In order to satisfy LAER/BACT requirements, Footprint Power proposes that the EDG will meet the Tier 2 standards and the FP will meet Tier 3 standards for off-road diesel engines. These both meet requirements specified under 40 CFR 89 as is specified in in MassDEP's Air Pollution Control Regulation at 310 CMR 7.26(42)(b) and represent the Top Case under MassDEP's June 2011 BACT Guidelines. Emissions will be controlled through the use of ULSD, good combustion practices and limited annual operation. With the exception of emergency situations, the units will typically operate no more than one hour per week, for testing and maintenance purposes. The specific EDG and FP BACT/LAER emission limits are shown in Tables 5-9 and 5-10.

Table 5-9 EDG Emission Standards

Pollutant	Tier II Standard	Emissions (lbs/hr)	Emissions (tpy)
NO_x [1]	6.4 g/kWh	11.60	1.74
CO	3.5 g/kWh	6.35	0.95
VOC[1]	1.3 g/kWh	2.36	0.35
$PM/PM_{10}/PM_{2.5}$	0.2 g/kWh	0.42[2]	0.06[2]
SO_2 [3]	NA	0.011	0.002

1 Tier 2 standard for NO_x and VOC is 6.4 g/kWh, combined. For worst case potential emissions, assumed NO_x emissions equal to this level and VOC emissions equal to the older Tier 1 limit of 1.3 g/kWh.

2 This reflects the addition of approximately 0.032 g/kWh for condensable particulate to the Tier 3 standard based on AP-42 ratios.

3 There is no Tier 2 limit for SO_2 emissions, SO_2 emissions are limited based upon fuel sulfur content of 15 ppm (0.0015 lb/MMBtu).

Table 5-10 FP Emission Standards

Pollutant	Tier III Standard	Emissions (lbs/hr)	Emissions (tpy)
NO_x[1]	4.0 g/kWh	2.44	0.37
CO	3.5 g/kWh	2.14	0.32
VOC[1]	1.3 g/kWh	0.79	0.12
$PM/PM_{10}/PM_{2.5}$	0.2 g/kWh	0.14[2]	0.02[2]
SO_2[3]	NA	0.004	0.0006

1 Tier 3 standard for NO_x and VOC is 4.0 g/KWh, combined. For worst case potential emissions, assumed NO_x emissions equal to this level and VOC emissions equal to the older Tier 1 limit of 1.3 g/kWh.

2 This reflects the addition of approximately 0.032 g/kWh for condensable particulate to the Tier 3 standard based on AP-42 ratios.

3 There is no Tier 2 limit for SO_2 emissions, SO_2 emissions limited based upon fuel sulfur content of 15 ppm (0.0015 lb/MMBtu).

6.0 AIR QUALITY IMPACT ANALYSIS

6.1 Introduction

The dispersion modeling analyses for this project were conducted in accordance with the USEPA's *Guideline on Air Quality Models* (USEPA, November, 2005) and MassDEP's *Modeling Guidance of Significant Stationary Sources of Air Pollution* (MassDEP, June 2011), and as described in the Air Quality Modeling Protocol for the Footprint Power Salem Harbor Redevelopment Project (submitted to the MassDEP on August 29, 2012). MassDEP concurrence with Protocol methodologies was provided on September 20, 2012.

Dispersion modeling has been conducted for CO, NO_2, PM_{10} and $PM_{2.5}$ to demonstrate compliance with the National Ambient Air Quality Standards (NAAQS) and PSD Increments. Modeling has also been conducted for SO_2 and air toxic pollutants for comparison with MassDEP's Allowable Ambient Levels (AALs) and Threshold Effects Exposure Limits (TELs).

The dispersion modeling for this project has been conducted in a manner that evaluates worst case operating conditions in an effort to predict the highest impact for each pollutant and averaging period. Maximum predicted impacts from the worst case scenarios are compared to the Significant Impact Levels (SILs) listed in Table 6-1. If maximum predicted impacts are below the corresponding SILs, then compliance is demonstrated and no additional analysis is necessary. However, for pollutants with predicted impacts that are greater than the SILs, a cumulative impact analysis has been conducted with other major emission sources in the area, as identified by MassDEP. Cumulative modeling concentrations are compared to the NAAQS whereas SHR Facility impacts are compared to the PSD Increments.

Table 6-1 Significant Impact Levels (SILs) for Applicable Criteria Pollutants

Pollutant	1-hour	3-hour	8-hour	24-hour	Annual
CO	2,000 μg/m³	--	500 μg/m³	--	--
NO_2	7.5 μg/m³	--	--	--	1 μg/m³
SO_2	7.8 μg/m³.	25 μg/m³		5 μg/m³	1 μg/m³
PM_{10}	--	--	--	5 μg/m³	1 μg/m³
$PM_{2.5}$	--	--	--	1.2 μg/m³	0.3 μg/m³

Consistent with EPA guidance, comparison with SILs is based on the five-year average of maximum predicted impact concentrations for $PM_{2.5}$ (both 24-hour and annual), 1-hour SO_2, and 1-hour NO_2. All other pollutants and averaging periods have been evaluated based on maximum predicted impacts across the five years of modeled concentrations.

6.2 Source Data and Operating Scenarios

The modeling analysis includes the combustion turbine units, the auxiliary boiler, the emergency generator, and the fire pump engine. The air dispersion modeling has been conducted for a range of operating scenarios to capture worst case potential impact concentrations from the combustion turbine units. Table 6-2 summarizes stack characteristics for the combustion turbine stacks. Table 6-3 provides emission rates and stack parameters which bracket the full range of operating loads inclusive of the Siemens and GE turbine options. A worst case startup condition is also included. Tables 6-4 through 6-7 provide the stack parameters for the ancillary units.

Table 6-2 Stack Characteristics

Parameter	Turbine Stacks	Auxiliary Boiler Stack	Emergency Generator Stack	Fire Pump Engine Stack	Auxiliary Cooling Tower
Base Elevation, msl (feet/meters)	16 / 4.9	16 / 4.9	16 / 4.9	16 / 4.9	16 / 4.9
Stack Height (feet/meters)	230 / 70.1	125 / 38.1	86 / 26.2	25 / 7.6	23.3 / 7.1
Inside Stack Diameter (feet/meters)	28.3 / 8.6 (Corresponds to the effective area of both adjacent flues)	3 / 0.9	1 / 0.3	1 / 0.3	12 / 3.6
Number of Stacks	1 (with 2 adjacent flues modeled as a single stack)	1	1	1	3
Predominant Land Use Type	Rural	Rural	Rural	Rural	Rural
Stack Location (in NAD83): UTM-E (m) UTM-N(m)	345,736.0 4,709,830.7	345,789.6 4,709,824.1	345,739.0 4,709,854.0	345,808.0 4,709,848.0	345,837.0 4,709,808.2

Table 6-3 Turbine Load Scenarios and Emission Rates

Turbine Manufacturer	Siemens	GE	GE	GE	GE
Operating Load	100%	100%	75%	46%	Startup
Ambient Temperature (deg F)	90	90	20	20	50
Evap Cooler and Duct Firing Status	ON	ON	OFF	OFF	OFF
Combined Turbine and Duct Firing Rate (MMBtu/hr) (both turbines)	4904.6	4834	3580	2720	2530
Comment	Max Firing Case - Siemens	Max Firing Case – GE	Intermediate Firing Case - GE	Low Firing Case - GE	Startup Worst Case Hour
Stack Exhaust Velocity (m/s)	21.06	18.68	15.82	11.95	12.89
Stack Exhaust Temperature (°K)	373.71	365.82	357.26	352.59	344.59
CO (g/s) (both turbines)	2.78	2.75	2.03	1.95	134.82
NO_X (g/s) (both turbines)	4.57	4.51	3.34	2.54	23.17
SO_2 (g/s) (both turbines)	0.927	0.914	0.677	0.514	0.479
$PM_{2.5}$ (g/s) (both turbines)	3.53	4.06	2.92	2.80	2.60
PM_{10} (g/s) (both turbines)	3.53	4.06	2.92	2.80	2.60

Table 6-4 Auxiliary Boiler Exhaust Parameters

Operating Load Cases Heat Input (Natural gas)	Full 80 MMBtu/hr
Stack Exhaust Velocity (m/s)	21.4
Stack Exhaust Temperature (°K)	549.82
CO (g/s)	0.35
NOx (g/s)	0.11
$PM_{2.5}$ (g/s)	0.050
PM_{10} (g/s)	0.050
SO_2 (g/s)	0.015

Table 6-5 Emergency Generator Exhaust Parameters

Operating Load Case Heat Input (ULSD)	Full (1102 BHP) 7.4 MMBtu/hr
Stack Exhaust Velocity (m/s)	34.5
Stack Exhaust Temperature (°K)	599.82
CO (g/s)	0.80
NO_x (g/s) *	0.050
$PM_{2.5}$ (g/s)	0.053
PM_{10} (g/s)	0.053
SO_2 (g/s)	1.4e-3

* Consistent with EPA guidance for intermittent sources, NOx emission rates based on maximum firing rates and scaled for annual capacity factors limited to 300 hours per year.

Table 6-6 Fire Pump Exhaust Parameters

Operating Load Case Heat Input (ULSD)	Full (371 BHP) 2.7 MMBtu/hr
Stack Exhaust Velocity (m/s)	10.9
Stack Exhaust Temperature (°K)	710.93
CO (g/s)	0.27
NOx (g/s) *	0.011
$PM_{2.5}$ (g/s)	0.018
PM_{10} (g/s)	0.018
SO_2 (g/s)	5.0e-4

* Consistent with EPA guidance for intermittent sources NO_x emission rates based on maximum firing rates and scaled for annual capacity factors limited to 300 hours per year.

Table 6-7 Auxiliary Cooling Tower Exhaust Parameters

Operating Load Case	100% Load 3 Cells
Stack Exhaust Velocity (m/s)	11.9
Stack Exhaust Temperature (°K)	1.2K above ambient temperature
$PM_{2.5}$ (g/s)	0.00164
PM_{10} (g/s)	0.0041

6.3 Model Selection

The EPA recommended AERMOD modeling system was used to conduct the dispersion modeling. The current versions of the model were used (AERMOD version 12060, AERMAP version 11103) to model both criteria pollutants and air toxics.

6.4 Meteorological Data for AERMOD

The modeling was conducted using five years (2006-10) of National Weather Service (NWS) meteorological data. The surface data is from the Logan Airport station in Boston, Massachusetts and the corresponding upper air data is from Gray, Maine. These stations are the closest NWS stations and most representative of the Salem area. AERMET (version 11059) and AERMINUTE (version 11059) and

AERSURFACE were employed to prepare the meteorological files. The files were provided by the MassDEP (Steve Dennis, via email on October 13, 2011).

6.5 Land-Use

A land-use determination has been made following the classification technique suggested by Auer in accordance with EPA/MassDEP modeling guidance. The classification determination was conducted by assessing land-use categories within a 3-km radius of the proposed site. Figure 6-1 provides a section of USGS map noting Salem Power Station and the 3-km radius around the site. Inspection of this section of USGS map and aerial photos indicates the majority of land use is characterized as rural and water-covered (approximately 64%). Therefore, rural dispersion coefficients will be used for the air quality modeling.

6.6 GEP/BPIP Analysis

A Good Engineering Practice (GEP) stack height analysis has been performed based on the proposed plant structures to determine the potential for building-induced aerodynamic downwash for the proposed stacks. The analysis procedures described in EPA's Guidelines for Determination of Good Engineering Practice Stack Height (EPA, 1985) and MassDEP guidance have been used.

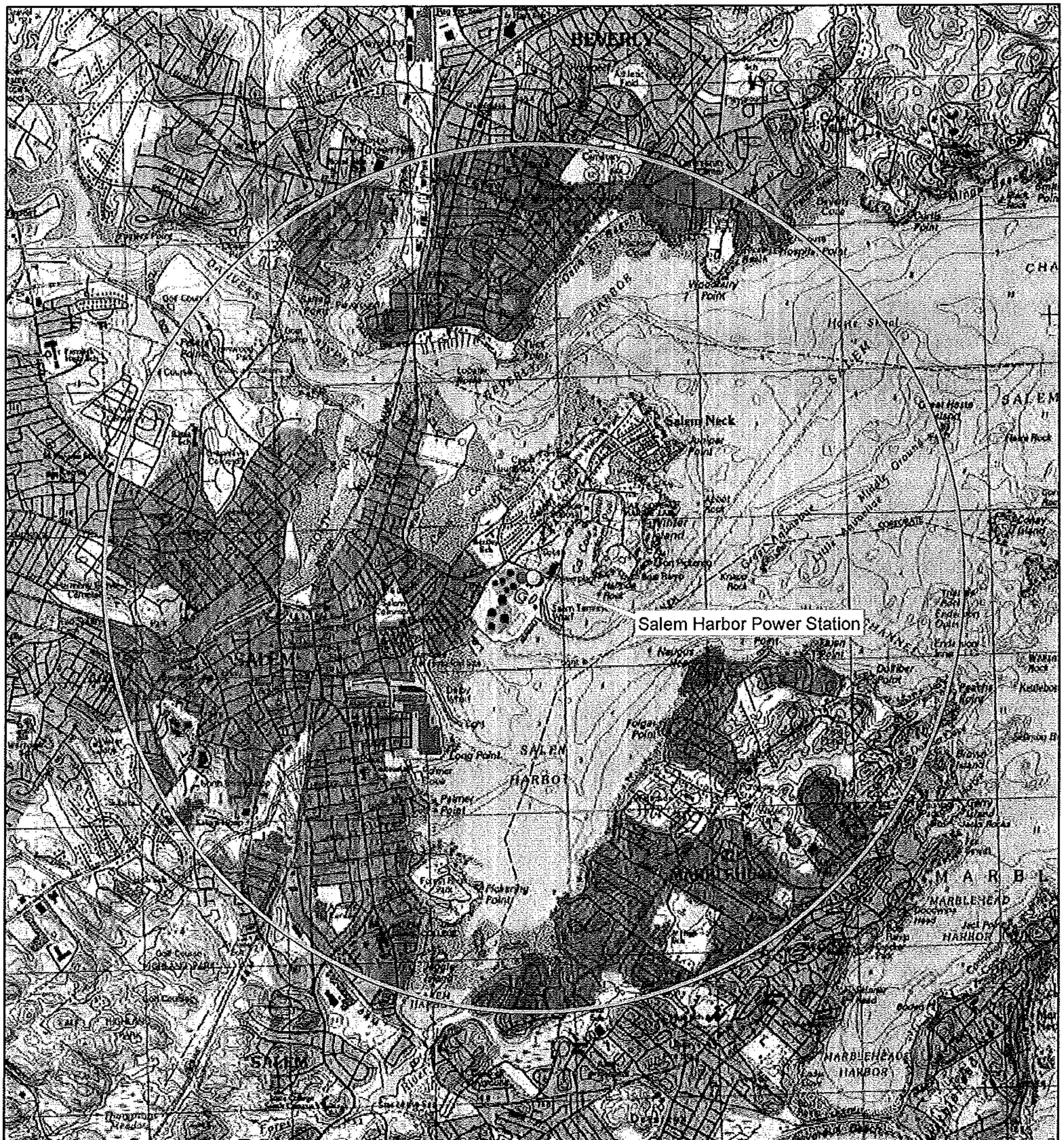
The GEP formula height is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground level concentrations at a closer proximity to the building than what would otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided. The GEP formula stack height, as defined in the 1985 final regulation, is calculated as follows:

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

Where:

- H_{GEP} is calculated GEP formula height,
- H_{BLDG} is the height of the nearby structure, and
- L is the lesser dimension (height or projected width) of the nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto the plane perpendicular to the direction of the wind. The GEP stack height is based on the plane project of any structure which results in the greatest calculated height. For the purpose of the GEP analysis, nearby refers to the "sphere of influence" defined as 5 times L (the lesser dimension [height or projected width] of the nearby structure), downwind from the trailing edge of the structure. The GEP stack height is 312.5 feet. The EPA's Building Profile Input Program (BPIP, Dated: 04274) version that is appropriate for use with the PRIME algorithms in AERMOD has been used to evaluate downwash effects in the model. The building dimensions and coordinates for each potentially influencing structure were input in BPIPPRM program to determine direction specific building data. The PRIME algorithms calculate the entire structure of the structure's wake, from the cavity immediately downwind of the building, to the far wake. Figure 6-2 presents the site layout for the new equipment with structure heights. The BPIPPRM input and output results are provided in Appendix F.



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W E
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Figure 6-1
Urban / Rural Land Use Determination Map
Salem Harbor Power Station
Salem, MA

Legend
- Power Station Location
- 3km Buffer of Power Station
- Urban Area

Basemap: 1991 USGS Topographic Map

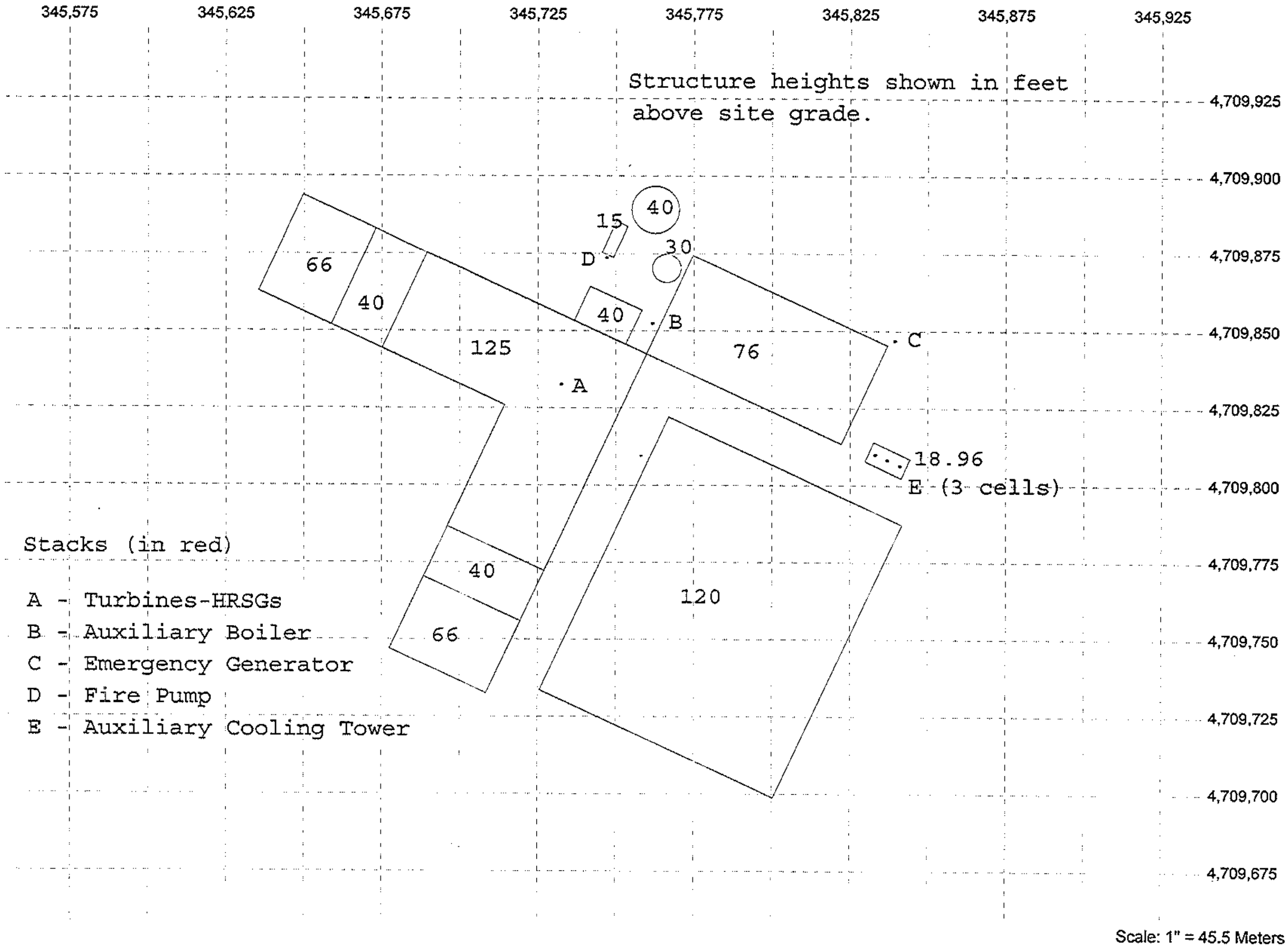
TETRA TECH EC, INC.

Overview Map

VT NH NY MA CT RI

Path: P:\GIS\Guerth\Salem\GIS\Spatial\MXD\Fig6_1_Urban_Areas.mxd

Figure 6-2 Site Layout with Structure Heights



6.7 Receptor Grid and AERMAP Processing

Discrete receptors were placed at 20-meter intervals along the facility fence line. In addition, a nested Cartesian grid was extended out from the fence line at the following receptor intervals and distances:

- At 50 meter intervals from the fence line to 300 meters;
- At 100 meter intervals from the 300 meters to 1,000 meters;
- At 500 meter intervals from 1,000 to 5,000 meters;
- At 1,000 meter intervals from 5,000 to 10,000 meters; and
- At 2,000 meter intervals from 10,000 to 20,000 meters.

Terrain elevations at receptors were obtained using BEE-Line Software's BEEST program and USGS digital terrain data. BEEST implements the AERMAP model which includes processing routines that extract National Elevation Data (NED) at 10-meter spacing based on North American Datum of 1983 (NAD83). The four nearest data points surrounding each receptor were used to determine receptor terrain elevations (by interpolation) for air quality model input.

6.8 Modeling Methodology

The modeling analysis has been conducted using AERMOD along with the set of representative meteorological data as described in Section 6.4. The analysis was conducted to demonstrate compliance with the ambient air quality standards and PSD increments, as well as AALs and TELs for toxics emissions. If maximum impacts from the Project criteria pollutant emissions are predicted to exceed their associated SILs shown in Table 6-1, a refined cumulative modeling analysis with additional major sources was then conducted to determine compliance with the NAAQS. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the project, the modeled impacts from "nearby" background sources, and representative ambient background concentrations. Compliance with the PSD Increments will be based on the sum of the modeled impacts attributable to the project plus the modeled impacts from "nearby" increment-consuming sources, if any. Footprint Power requested an inventory from MassDEP of sources to include in the multi-source modeling analysis after the significant impact areas were determined from the project source-only modeling. The NAAQS compliance assessment for short term CO and PM_{10} is based on the highest 2^{nd} highest short-term impacts from the proposed project, as well as the potentially influencing background emission sources plus background concentrations. Consistent with recent EPA guidance, the NAAQS compliance assessment for 1-hour NO_2 is based on average 98% design values for both the predicted impact concentrations (maximum of the 5-year average highest eighth highest (H8H) values) and ambient background (3-year average of measured 98% design values).

Also consistent with EPA guidance, the NAAQS compliance assessment for 24-hour $PM_{2.5}$ is based on the 5-year average of the predicted first highest 24-hour concentrations and are combined with the 3-year average of the measured ambient background 98% design values. The NAAQS and PSD Increments are presented in the Table 6-8 below.

Table 6-8 Ambient Air Quality Standards for Applicable Pollutants

Pollutant	Averaging Period	NAAQS ($\mu g/m^3$)	Class II Increments ($\mu g/m^3$)
CO	1-hour	10,000	NA
	8-hour	40,000	NA
NO_2	1-hour	188	NA
	Annual	100	25
PM_{10}	24-hour	150	30
	Annual	NA	17
$PM_{2.5}$	24-hour	35	9
	Annual	12	4
SO_2	1-hour	196	NA
	3-hour	1300	512
	24-hour	365	91
	Annual	80	20

6.9 Significant Impact Area (SIA) Determination

The air quality dispersion modeling analysis was performed in accordance with the procedures described in this protocol. Table 6-9 presents the predicted maximum ambient air quality impacts resulting from operation of the Project. As Table 6-9 shows, the predicted maximum ambient air quality impact concentrations are below SILs for all pollutants and averaging periods except 24-hour PM_{10}, 24-hour and annual $PM_{2.5}$, and 1-hour NO_2.

Table 6-9 Project Maximum Predicted Impact Concentrations Compared to Significant Impact Levels (micrograms/cubic meter)

Pollutant	Averaging Period	Maximum Predicted Salem Harbor Redevelopment Project Impact	SIL
PM_{10}	24-Hour	5.4	5
$PM_{2.5}$	24-Hour	4.4	1.2
	Annual	0.5	0.3
NO_2	1-Hour	44.3	7.5
	Annual	0.6	1
SO_2	1-Hour	1.1	7.8
	3-Hour	1.2	25
	24-Hour	0.7	5
	Annual	0.04	1
CO	1-Hour	438.7	2000
	8-Hour	213.4	500

Consistent with modeling guidance for significant impact determination, impact concentrations are based on the maximum predicted impacts across 5-years of modeled meteorological data, except for $PM_{2.5}$ (both

24-hour and annual), and 1-hour SO_2 and NO_2, which are based on the 5-year average of the 1st highest annual values.

In accordance with accepted EPA and MassDEP procedures, compliance is considered demonstrated for pollutants and averaging periods with maximum predicted impacts less than corresponding SILs, and no additional analysis is required. Since maximum predicted impact concentrations for 24-hour and annual $PM_{2.5}$, 24-hour PM_{10}, and 1-hour NO_2 are above the corresponding SILs, additional cumulative modeling analysis with other major emission sources in the area is necessary to demonstrate compliance with regulatory standards, NAAQS and MAAQS, which are equivalent.

The maximum concentrations for these pollutants from the SHR Facility are generally predicted just outside of the project fence line. Figures 6-3, 6-4, 6-5, and 6-6 present the concentration isopleth plots for 24-hour $PM_{2.5}$, annual $PM_{2.5}$, 24-hour PM_{10}, and 1-hour NO_2 predicted project concentrations, respectively. The extent of the significant impact area (where maximum predicted concentrations exceed the corresponding SIL) is approximately 1.2 kilometers, 0.5 kilometers, and 12.3 kilometers, for $PM_{2.5}$, PM_{10}, and NO_2, respectively. Based on this Significant Impact Area (SIA) determination, the SHR Project requested that the MassDEP provide the background source inventory of other major sources that should be considered in the cumulative modeling analysis. These sources are presented in Section 6.11 below.

6.10 Ambient Background Data

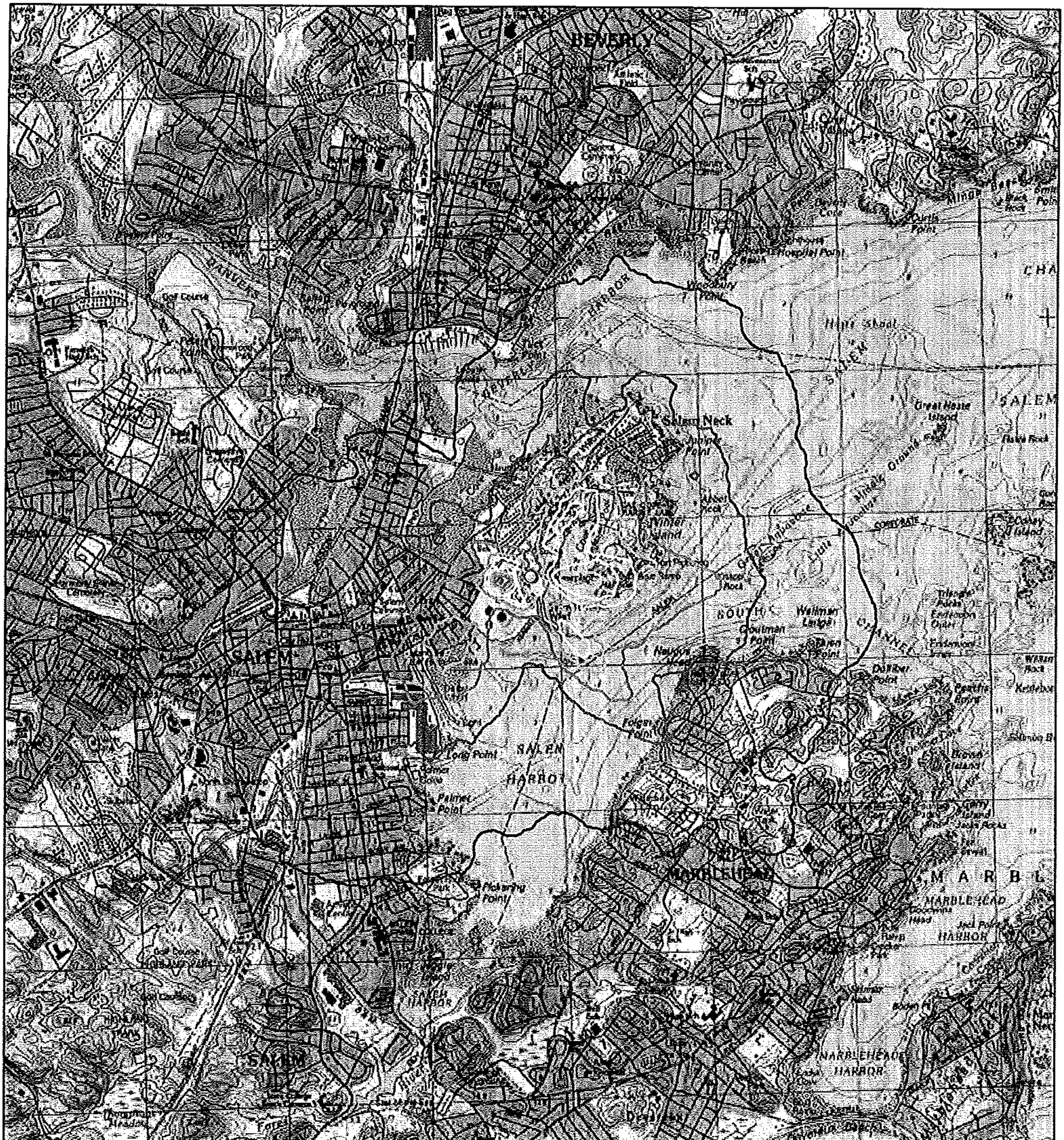
As stated above, since AERMOD predicted maximum impact concentrations are significant (above SILs) for 1-hour NO_2, 24-hour PM_{10} and 24-hour and annual $PM_{2.5}$, cumulative modeling of these pollutants with other major background emission sources was conducted. In the compliance assessment, representative ambient air quality background concentrations are also added to modeled concentrations from the cumulative modeling to compare against the NAAQS. Representative ambient air quality data and the selected background concentrations that have been used for the compliance assessment are provided below in Table 6-10.

Table 6-10 Salem Harbor Station Redevelopment Project Background Air Quality Concentrations (All Concentrations in Micrograms per Cubic Meter)

Pollutant	Representative DEP Monitoring Location	Averaging Time[3]	Background Concentration[3]	National and Massachusetts Ambient Air Quality Standards
Nitrogen Dioxide	Lynn[1]	1-hour	82.3	188
Particulate Matter 2.5	Lynn[1]	24-hr Annual	19.2 7.3	35 12
Particulate Matter 10	Harrison Ave Boston[2]	24-hr	35	150

Notes:

1. The Lynn monitoring location is approximately 5.9 miles southwest of the Salem Harbor site.
2. The Harrison Avenue monitoring location is approximately 17 miles southwest of the Salem Harbor site.
3. Background concentrations are based on the measured values from 2009-2011. Short-term concentrations (24-hours or less) are generally the maximum second highest value over the 3 years (2009-2011), or in the case of 24-hour $PM_{2.5}$, and 1-hour NO_2 the average of the 98^{th} percentile values. The long-term value for PM_{10} is also based on the 3 year average. These assumptions are consistent with the form of the ambient air quality standards for the pollutant.



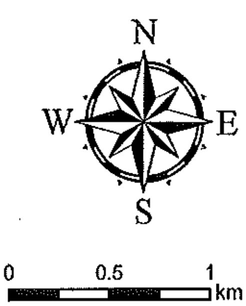


Figure 6-3
AERMOD Predicted Concentrations
Isopleths for Maximum 24-Hour PM 2.5 (5 year average)
Salem Harbor Power Station
Salem, MA

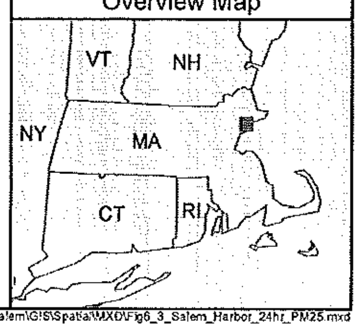
Legend

Power Station Location

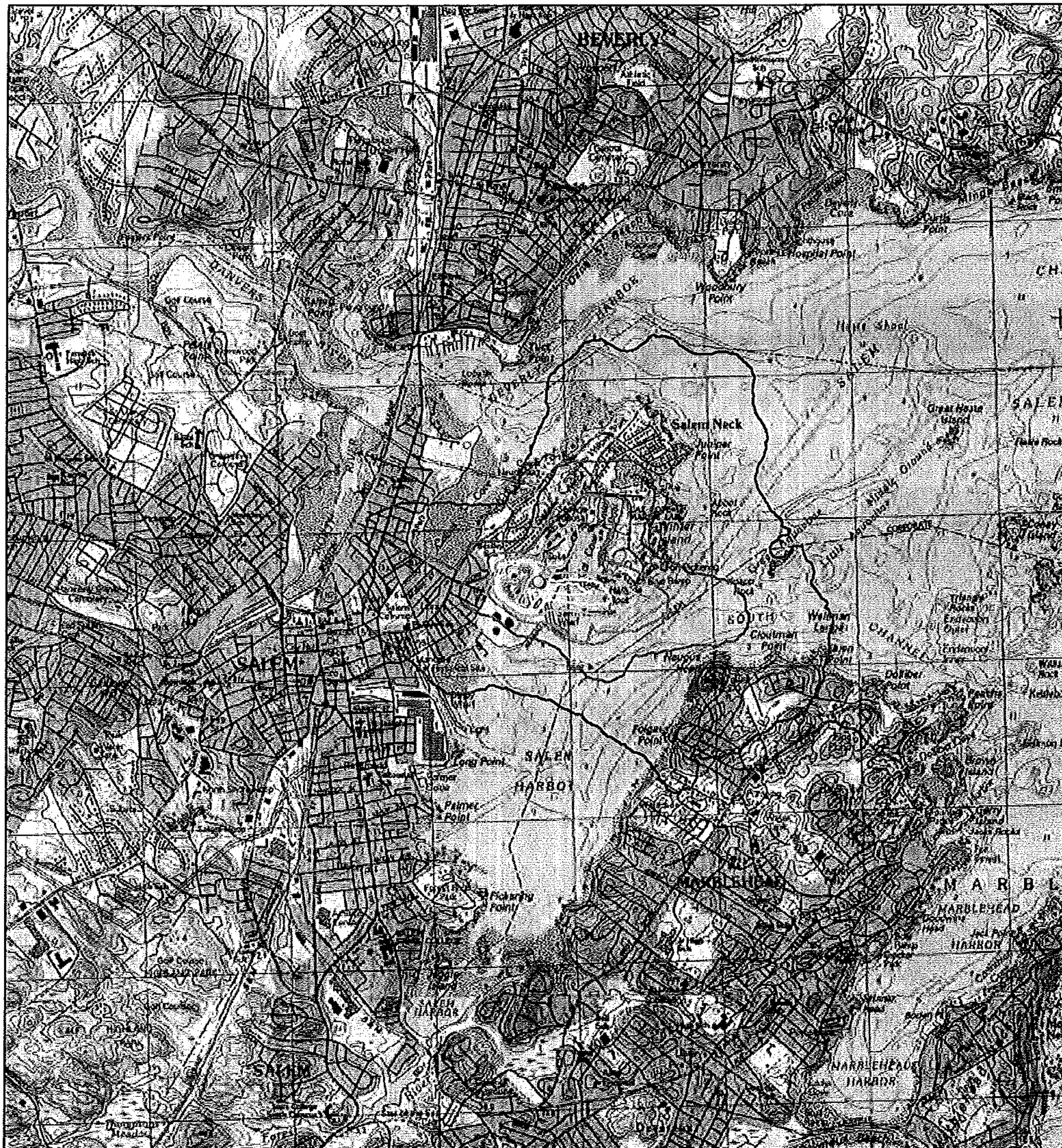
24-Hour PM2.5 Concentration Contour (µg/m3)

0.4 0.8 1.2 1.6 2.0 2.4 2.8 3.2 3.6 4.0

Overview Map



Path: P:\GIS\Guertin\Salem\GIS\Spatial\MXD\Fig6_3_Salem_Harbor_24hr_PM25.mxd



0 0.5 1 km

Figure 6-4
AERMOD Predicted Concentrations
Isopleths for Annual PM 2.5 (5 year average)
Salem Harbor Power Station
Salem, MA

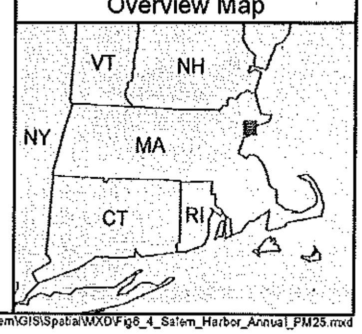
Legend

Power Station Location

Annual PM2.5 Concentration Contour (µg/m3)

0.05 0.10 0.15 0.20 0.25 0.30 0.35 0.40 0.45 0.50

Overview Map



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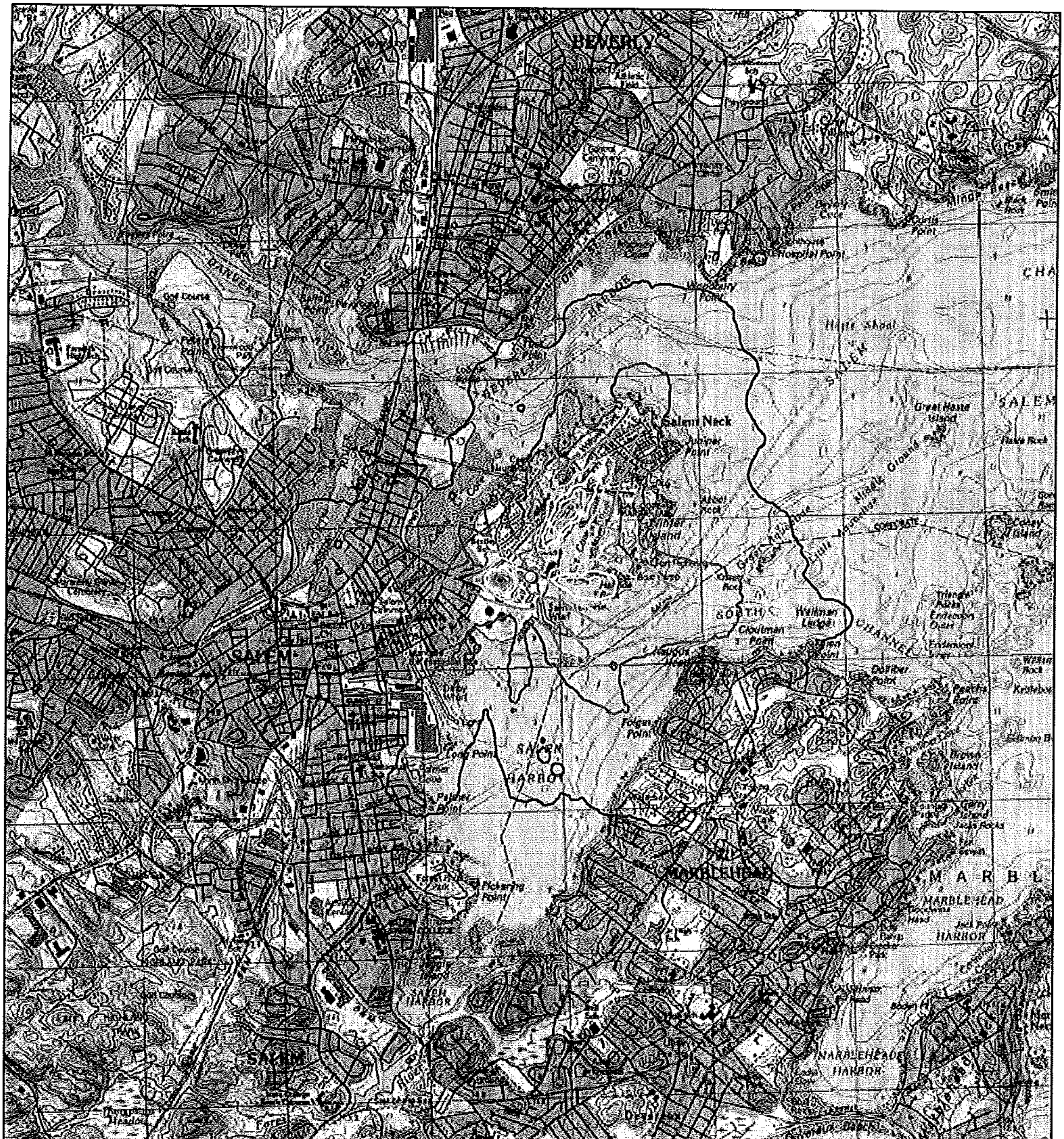


N
W
E
S

0 0.5 1 km

Figure 6-5

AERMOD Predicted Concentrations
Isopleths for Maximum 24-Hour PM 10 (worst case year - 2008)
Salem Harbor Power Station
Salem, MA

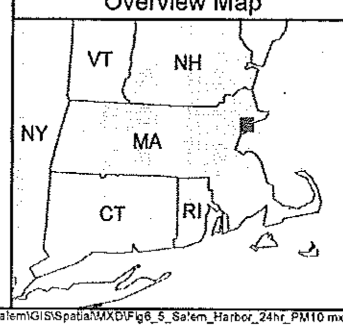
Legend

Power Station Location

24-Hour PM10 Concentration Contour (µg/m3)

0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5

Overview Map



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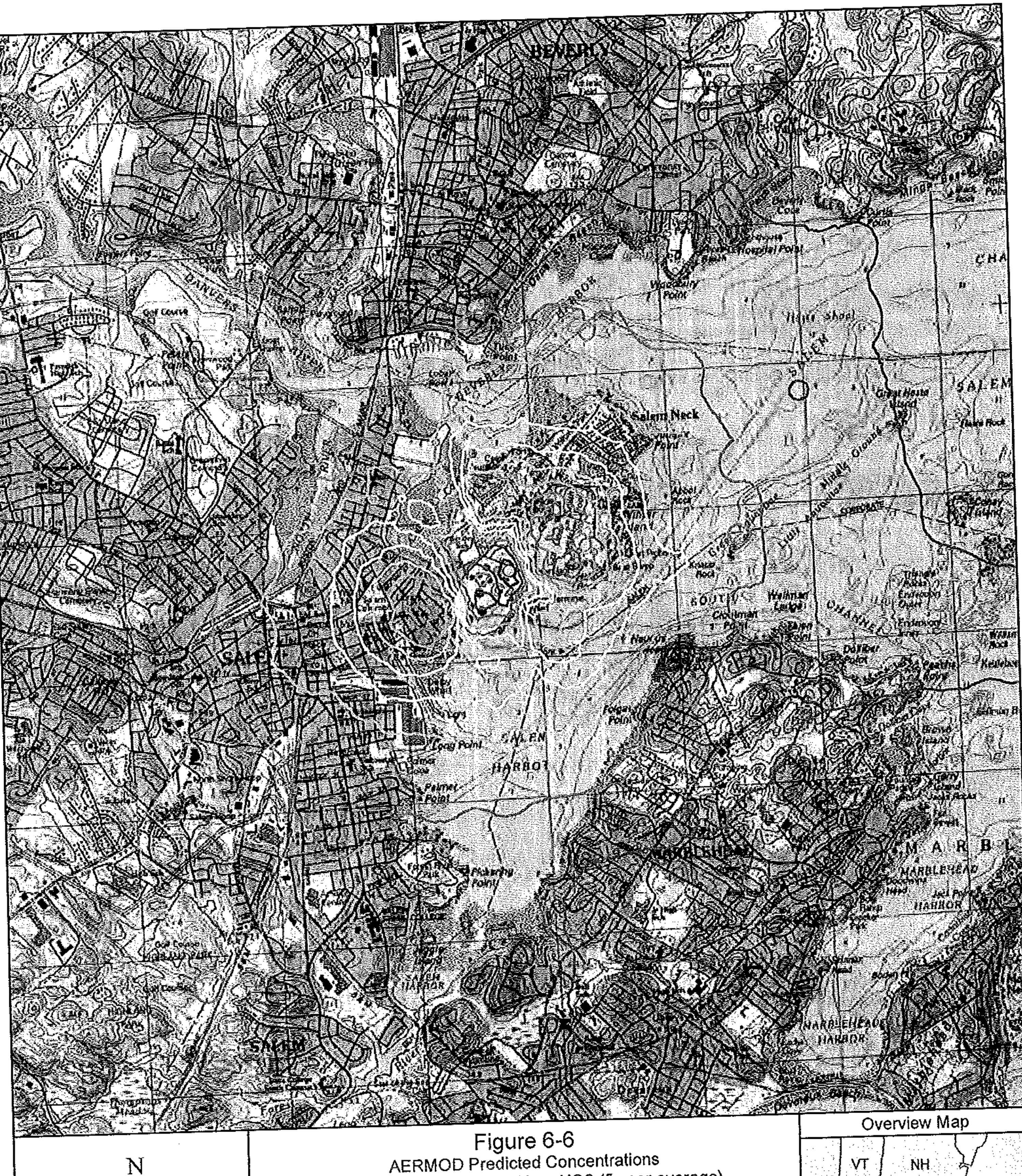


N
W E
S

0 0.5 1 km

Figure 6-6
AERMOD Predicted Concentrations
Isopleths for Maximum 1-Hour NO2 (5 year average)
Salem Harbor Power Station
Salem, MA

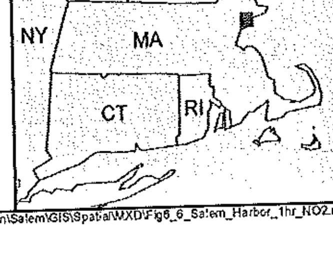
Legend

Power Station Location

1-Hour NO2 Concentration Contour (µg/m3)

4 8 12 16 20 24 28 32 36 40

Overview Map



Path: P:\GIS\Guertin\Salem\GIS\Spatial\MXD\Fig6_6_Salem_Harbor_1hr_NO2.mxd

6.11 NAAQS and PSD Compliance Assessments

As described above, the SHR Facility has significant predicted impact concentrations for 1-hour NO_2, 24-hour PM_{10}, and 24-hour and annual $PM_{2.5}$. The MassDEP was contacted to determine if there are sources of NO_2 and PM in the region that should be considered in a cumulative modeling analysis with the SHE facility. The interacting sources provided by the DEP for 1-hour NO_2 modeling are:

1. General Electric Aviation Facility in Lynn, MA, and
2. Wheelabrator Waste-to-Energy Facility in Saugus, MA.

Detailed emissions and stack parameter data for these sources is provided in Appendix F. According to MassDEP, there are no interacting sources of PM_{10} or $PM_{2.5}$ that need to be considered in the cumulative modeling analysis.

Table 6-11 presents the results of the NAAQS compliance assessment. This assessment includes the predicted cumulative impacts of the facility and background sources plus the representative ambient background concentrations. As shown in Table 6-11, the resulting total concentrations for $PM_{2.5}$, PM_{10}, and NO_2 are below the corresponding NAAQS concentrations. Model predicted NO_2 concentrations conservatively assume 100% conversion of NO_X to NO_2.

Table 6-11 Salem Harbor Station Redevelopment Project NAAQS Compliance Assessment (micrograms/cubic meter)

Pollutant	Averaging Period	Cumulative Impact Concentration[1]	Background	Total Impact Plus Background	NAAQS
$PM_{2.5}$ (µg/m^3)	24-Hour	4.4	19.2	23.6	35
$PM_{2.5}$ (µg/m^3)	Annual	0.5	7.3	7.8	12
PM_{10} (µg/m^3)	24-Hour	5.4	35	40.4	150
NO_2 (µg/m^3)	1-Hour	102.6	82.3	184.9	188

[1]Consistent with modeling guidance for NAAQS compliance assessments, project impact concentrations are based on the 5-year average of the 1st highest values occurring in each year for 24-hour and annual $PM_{2.5}$ concentrations, and the 5-year average of the 8th highest daily maximum concentrations occurring in each year for 1-hour NO_2. The annual project impact concentration for 24-hour PM_{10} is the maximum predicted concentration over 5 years.

The PSD NSR program also requires a demonstration that the proposed facility, in combination with other PSD increment-consuming emission sources, will comply with the maximum allowable PSD "increment." This analysis is required because the facility is subject to PSD NSR for $PM_{2.5}$, PM_{10}, and NO_2, and also has a maximum predicted $PM_{2.5}$, PM_{10}, and NO_2 impacts greater than the corresponding SIL concentrations.

Table 6-12 presents the results of the PSD increment compliance for $PM_{2.5}$ (24-hour and annual), and PM_{10} (24-hour). As shown in Table 6-12, the resulting project impact concentrations are less than the maximum allowable PSD increments for both 24-hour and annual $PM_{2.5}$, and 24-hour PM_{10}. There is currently no PSD increment for 1-hour NO_2 concentrations.

Table 6-12 Salem Harbor Station Redevelopment Project PSD Increment Compliance Assessment (micrograms/cubic meter)

Pollutant	Averaging Period	Project Increment Consumption[1]	Maximum Allowable PSD Increment
$PM_{2.5}$ (µg/m3)	24-Hour	4.4	9
$PM_{2.5}$ (µg/m3)	Annual	0.5	4
PM_{10} (µg/m3)	24-Hour	5.4	30

[1]Consistent with modeling guidance for PSD increment compliance assessments, impact concentrations are based on the 5-year average of the 1st highest values occurring in each year for 24-hour and annual PM-2.5 concentrations, and the highest predicted concentration across 5 years for 24-hour PM-10 concentrations.

6.12 Air Toxics Analysis

The MassDEP Office of Research and Standards (ORS) has established health-based ambient air guidelines for a variety of chemicals. These air guidelines establish two limits for each chemical listed: an allowable ambient limit, which is based on an annual average concentration; and a threshold effects exposure limit, which is based on a 24-hour time period. In general, AALs are lower than TELs, and represent the concentration associated with a one in a million excess lifetime cancer risk, over a lifetime of continuous exposure. For chemicals that do not pose cancer risks, the AAL is equal to the TEL.

Table 6-13 presents the projected maximum impacts for each air pollutant that will potentially be emitted by the SHR Facility, for which an AAL or TEL has been established. Impacts are based on the worst-case emission scenarios predicted by AERMOD, which occur at a partial load of 1,360 MMBtu/hr for each combustion turbine, and 100% load operation for the auxiliary boiler, emergency generator, and fire pump engine. Since the emergency generator and fire pump engine are limited to 300 hours of operation per year, the annual project impacts only include 300 hours of emissions from each of these emission units, which is then divided evenly among 8,760 hours per year. As shown, the resulting SHR Facility concentrations are significantly less than the maximum AAL/TEL guideline values.

Table 6-13 Salem Harbor Station Redevelopment Project Maximum Project Impacts Compared to DEP Air Toxics TELs and AALs (micrograms/cubic meter)

Pollutant	Averaging Period (Criterion)	Maximum Projected Impact (µg/m^3)	Criterion Value [SIL or TEL/AAL] (µg/m^3)	Impact as % of Criterion
Acetaldehyde	24-hour (TEL)	0.048926	2	2.446%
	Annual (AAL)	0.000678	0.5	0.136%
Ammonia	24-hour (TEL)	1.140820	100	1.141%
	Annual (AAL)	0.033211	100	0.033%
Benzene	24-hour (TEL)	0.075227	1.74	4.323%
	Annual (AAL)	0.000514	0.12	0.428%
1,3-Butadiene	24-hour (TEL)	0.001761	1.20	0.147%
	Annual (AAL)	0.000015	0.003	0.488%
o-Dichlorobenzene	24-hour (TEL)	0.000264	81.74	0.0003%
	Annual (AAL)	0.000030	81.74	0.00004%
p-Dichlorobenzene	24-hour (TEL)	0.000264	122.61	0.0002%
	Annual (AAL)	0.000030	0.18	0.017%
Ethylbenzene	24-hour (TEL)	0.013521	300	0.005%

Pollutant	Averaging Period (Criterion)	Maximum Projected Impact (µg/m³)	Criterion Value [SIL or TEL/AAL] (µg/m³)	Impact as % of Criterion
	Annual (AAL)	0.000394	300	0.0001%
Formaldehyde	24-hour (TEL)	0.215064	2.0	10.753%
	Annual (AAL)	0.006429	0.8	0.804%
Naphthalene	24-hour (TEL)	0.009474	14.25	0.066%
	Annual (AAL)	0.000067	14.25	0.0005%
Propylene oxide	24-hour (TEL)	0.315089	6	5.251%
	Annual (AAL)	0.001661	0.3	0.554%
Sulfuric Acid	24-hour (TEL)	0.458684	2.72	16.863%
	Annual (AAL)	0.015315	2.72	0.563%
Toluene	24-hour (TEL)	0.083765	80	0.105%
	Annual (AAL)	0.001812	20	0.009%
Xylenes	24-hour (TEL)	0.046515	11.80	0.394%
	Annual (AAL)	0.000878	11.80	0.007%
Arsenic	24-hour (TEL)	0.000048	0.003	1.590%
	Annual (AAL)	0.000005	0.0003	1.656%
Beryllium	24-hour (TEL)	0.000003	0.001	0.264%
	Annual (AAL)	0.0000003	0.0004	0.074%
Cadmium	24-hour (TEL)	0.000242	0.003	8.069%
	Annual (AAL)	0.000027	0.001	2.724%
Chromium (total)	24-hour (TEL)	0.001320	1.36	0.097%
	Annual (AAL)	0.000039	0.68	0.006%
Chromium (hexavalent)	24-hour (TEL)	0.000238	0.003	7.941%
	Annual (AAL)	0.000007	0.0001	7.039%
Copper	24-hour (TEL)	0.00018	0.54	0.034%
	Annual (AAL)	0.00002	0.54	0.004%
Lead[1]	24-hour (TEL)	0.00017	0.14	0.122%
	Annual (AAL)	0.000012	0.07	0.018%
Mercury	24-hour (TEL)	0.00006	0.14	0.040%
	Annual (AAL)	0.000006	0.07	0.009%
Nickel	24-hour (TEL)	0.00058	0.14	0.216%
	Annual (AAL)	0.00005	0.07	0.029%
Selenium	24-hour (TEL)	0.00003	0.27	0.005%
	Annual (AAL)	0.0000007	0.18	0.0001%
Vanadium	24-hour (TEL)	0.00051	0.54	0.187%
	Annual (AAL)	0.00006	0.54	0.021%

[1]Most of the air pollutants that are regulated under the AAL/TEL program do not have ambient air quality standards. Lead is the one pollutant that is regulated under the AAL/TEL program and also has an AAQS.

7.0 EVALUATION OF ADDITIONAL IMPACTS

In accordance with Federal PSD regulations, additional impacts must be addressed for projects subject to PSD review. The additional PSD impact analyses involving modeling are discussed below.

7.1 Class I Area Air Quality Related Values (AQRVs)

The nearest Class I Areas to the Project are as follows:

- Lye Brook National Wilderness Area (NWA), VT – approximately 186 kilometers away;
- Presidential Range / Dry River NWA, NH – approximately 185 kilometers away;
- Great Gulf, NWA, NH - approximately 199 kilometers away.

Since annual project emissions are not substantially greater than the major source thresholds and the closest Class I Areas are nearly 200 km away, no impact assessment has been conducted for the Class AQRVs.

7.2 Visibility

The VISCREEN model was used to assess potential visibility impacts at the closest Class I Area, the Presidential Range / Dry River NWA (185 km away). The Project's maximum potential emissions were used in the analysis. The results (provided in Appendix F) indicate that the visibility impairment related to the project's plume will not exceed threshold criteria.

7.3 Soils and Vegetation

The EPA guidance document for soils and vegetation, A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals (EPA Screening Procedure) (EPA 450/2-81-078) established a screening methodology for comparing air quality modeling impacts to "vegetation sensitivity thresholds."

<u>Vegetation Assessment</u>

As an indication of whether emissions from the proposed project will significantly impact the surrounding vegetation (i.e., cause acute or chronic exposure to each evaluated pollutant), the modeled emission concentrations are compared against both a range of injury thresholds found in the guidance, as well as those established by the NAAQS secondary standards. Since the NAAQS secondary standards were set to protect public welfare, including protection against damage to crops and vegetation, comparing modeled emissions to these standards will provide some indication if potential impacts are likely to be significant. Table 7-1 lists the project impact concentrations and compares them to the vegetation sensitivity thresholds and NAAQS secondary standards. All pollutant impact concentrations are below the vegetation sensitivity thresholds.

Table 7-1 Vegetation Impact Screening Thresholds

Pollutants	Averaging Period	Maximum Project Impacts (μg/m^3)	NAAQS Secondary Standards (μg/m^3	EPA's 1980 Screening Concentrations (μg/m^3)
SO_2	1-hour	1.1	NA	917
	3-hour	1.2	1300	786
	Annual	0.04	NA	18

Pollutants	Averaging Period	Maximum Project Impacts (µg/m³)	NAAQS Secondary Standards (µg/m³	EPA's 1980 Screening Concentrations (µg/m³)
NO_2	4-hour	44.3[1]	NA	3760
	1 month	44.3[1]	NA	561
	Annual	0.6	100	94
CO	Week	213.4[1]	NA	1,800,000 (weekly)
PM_{10}	24-hour	5.4	150	None
$PM_{2.5}$	24-hour	5.4	35	None
	Annual	0.5	15	

[1] Conservatively based on shorter term average predicted concentration.

Soil Assessment

The EPA Screening Procedure also provides a method for assessing impacts to soils. This assessment evaluates trace element contamination of soils. Since plant and animal communities can be affected before noticeable accumulation occur in the soils, the approach used here evaluates the way soil acts as an intermediary in the transfer of a deposited trace element to the plants. For trace elements, the concentration deposited in the soil is calculated from the from the maximum predicted annual ground level concentrations conservatively assuming that all deposited material is soluble and available for uptake by plants. The amount of trace element potentially taken up by plants was calculated using average plant to soil concentration ratios. The calculated soil and plant concentrations were then compared screening concentrations designed to assess potential adverse effects to soils and plants. Table 7-2 presents the results of the potential soil and plant concentrations and compares them to the corresponding screening concentration criteria. A calculated concentration in excess of either of the screening concentration criteria is an indication that a more detailed evaluation may be required. However, as show in Table 7-2, calculated concentrations as a result of operation of the project are all well below the screening criteria.

Table 7-2 Soils Impact Screening Assessment

Pollutant	Deposited Soil Concentration (ppmw)	Soil Screening Criteria (ppmw)	Percent of Soil Screening Criteria	Plant Tissue Concentration (ppmw)	Plant Screening Criteria (ppmw)	Percent of Plant Screening Criteria
Arsenic	1.42E-03	3	0.0	1.99E-04	0.25	0.1
Cadmium	7.81E-03	2.5	0.3	8.36E-02	3	2.8
Chromium	1.12E-02	8.4	0.1	2.24E-04	1	0.0
Copper	5.89E-03	40	0.0	2.77E-03	0.73	0.4
Lead	3.56E-03	1000	0.0	1.60E-03	126	0.0
Mercury	1.78E-03	455	0.0	8.88E-04	NA	NA
Nickel	1.51E-02	500	0.0	6.78E-04	60	0.0
Selenium	1.97E-04	13	0.0	1.97E-04	100	0.0
Vanadium	1.63E-02	2.5	0.7	1.63E-04	NA	NA

Note: Based in screening procedures described in Chapter 5 of the EPA guidance document for soils and vegetation, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals."

7.4 Growth

A growth analysis examines the potential emissions from secondary sources associated with the proposed project. While these activities are not directly involved in project operation, the emissions involve those that can reasonably be expected to occur; for instance industrial, commercial, and residential growth that might occur in the project area due to the project itself. Secondary emissions do not include any emissions which come directly from the mobile source, such as emissions from the tailpipe of any on-road motor vehicle or the propulsion of a train (USEPA, 1990). They also do not include sources that do not impact the same general area as the source under review.

The Salem Harbor Redevelopment Project is expected to have an average construction and demolition work force of 320 workers (approximately 286 workers on site for construction activities only) during the approximate 23 month construction period (June 2014 to May 2016). A peak work force of approximately 590 workers is expected to be on-site for a period of about 3 months around the fall of 2015. A significant portion of the regional construction force in the area of the site is currently available to build the project. However, it is possible that a small percentage of the labor force will be from outside the commuting region, and may create a small new housing demand. However, it is expected that any new housing demand can be met with existing housing in the region. In addition, it is expected that no induced commercial or industrial construction in the area will be necessary to support the project. Therefore, an evaluation of secondary emission sources associated with the project is not warranted.

8.0 NONATTAINMENT NEW SOURCE REVIEW

The requirements for Plan Approval of major sources in nonattainment areas are specified in 310 CMR 7.00 Appendix A. The entire Commonwealth of Massachusetts including Salem was designated as nonattainment for 8-hour ozone prior to May 21, 2012, at which time all of the state except Dukes County (Martha's Vineyard and Elizabeth Islands) was re-designated to attainment by the EPA. However, the DEP has not modified the relevant nonattainment permitting regulations in 310 CMR 7.00 Appendix A (Appendix A) to reflect this recent change to attainment designation. Therefore, since the SHR Facility is a major source of NO_x (a precursor to ozone), the provisions of Appendix A apply to the Facility for this pollutant.[3]

The requirements for major sources located in nonattainment areas are categorized and described in subsections (4) through (8) of Appendix A as: control technology review, reasonable further progress, emissions offsets, source impact analysis, and additional conditions for approval. The SHR Facility's compliance with each of these requirement subsections is addressed in the following subsections.

8.1 Control Technology Review

In addition to complying with State Implementation Plan emissions limits, NSPS, and NESHAPs as is described for the SHR Facility in Section 4, the Facility must apply LAER control technology for NO_x. The demonstration of LAER for the SHR Facility is contained in Section 5 of this Major CPA application.

8.2 Reasonable Further Progress

310 CMR 7.00 Appendix A(5)(a) requires that reasonable further progress towards attainment must be represented by sufficient offsetting emissions in effect such that total emissions from existing sources, new minor sources, and the SHR Facility upon operation are sufficiently less than existing emissions prior to the plan approval application. As noted above, the Salem region has already achieved attainment status for ozone. Regardless, additional reasonable further progress will be shown due to the use of the approved emissions offsets for NO_x (see following subsection) as well as the removal from serivce of Salem Harbor Units 1 and 2 in December of 2011 and shutdown of Units 3 and 4 by June of 2014. In addition, an analysis by Charles River Associates (CRA) of displaced generation based on projected power plant dispatch throughout ISO New England (ISONE) with future operation of the SHR Facility has projected avoided emissions of 412 tons of NO_x (representing 6% of total ISONE emissions) in 2016 rising to 741 tons (representing 8% of total ISONE emissions) in 2020.[4]

8.3 Emissions Offsets

Since the SHR Facility will be a major source of NO_x, emissions offsets will be required. Regulation 310 CMR 7.00 Appendix B (3) (e) requires that a source owner/operator must secure 5% more Emission Reduction Credits (ERCs) than the ERCs needed for offsets in a serious non-attainment area (1.2 NO_x offsets are needed for each ton of NO_x potential emissions in serious non-attainment areas). Therefore,

[3] The other precursor pollutant regulated for ozone is VOC but VOC emissions from the SHR Facility are less than the major source threshold of 50 tons per year so VOC emissions are not regulated under Appendix A for this Facility.

[4] Charles River Associates, "Analysis of the Impact of Salem Harbor Repowering on New England Air Emissions", November 21, 2012.

1.26 times the NO_x potential to emit of 158.6 tons per year will be required for the SHR Facility or a total of 200 tons per year of NO_x offsets.

Emissions offsets must be obtained from the same non-attainment area, or from another non-attainment area of equal or more severe non-attainment classification, if emissions from the other area contribute to ozone non-attainment in the area where the source will be constructed. Since ozone is a regional air pollutant and the coastal location of Salem is downwind of most all locations within the Commonwealth of Massachusetts, most all approved ERCs generated in Massachusetts could potentially be used for offsets for the SHR Facility. In addition, Massachusetts has executed a Memorandum of Understanding with Rhode Island under which NO_x Emission Reduction Credits (ERCs) generated in Rhode Island may be used in Massachusetts to meet emission offset requirements of Appendix A.

MassDEP maintains an ERC Registry. The most recent version of this Registry is dated August 10, 2012 and this version shows 118 tons per year of rate-based ERCs generated by a shutdown at Haverhill Paperboard were approved by MassDEP on April 7, 2010. An additional 37 tons per year of rate-based ERCs from a shutdown at Natick Paperboard were approved on April 7, 2010. While these are currently the two largest rate-based ERC listings in the Registry, several other rate-based ERCs which have been approved and have not yet expired are listed. Rate-based ERCs from shutdowns are suitable for use as emissions offsets if used within 10 years of final approval.

In Rhode Island, Osram Sylvania shut down a glass furnace and other smaller units in 2002 and 2003 and 259.9 tons per year of NOx ERCs were approved for these shutdowns in March of 2004. Osram Sylvania has sold some of the credits but as of late November 2012, at least 135 tons per year remained available for offsets.

In addition, the MassDEP Registry contains entries of thousands of tons of mass-based ERCs which have been approved in Massachusetts. According to Appendix B, mass-based ERCs (in units of tons) can either be converted into rate-based ERCs (tons per year) and then used as emissions offsets or can be used directly as emissions offsets so long as at least 5 years of mass-based ERCs (1000 tons in the case of the SHR Facility) are maintained at all times that the Facility remains operational.

Prior to issuance of the CPA for the SHR Facility, Footprint Power will secure the rights to at least 200 rate based NOx ERCs (and/or the appropriate number of mass based NOx ERCs) to satisfy the offset requirement of 200 tons per year.

8.4 Source Impact Analysis

There are three additional ambient air quality impact considerations for compliance with Appendix A nonattainment regulations:

- The emissions offsets proposed in the prior section in conjunction with the proposed emissions increase due to the SHR Facility must have a net air quality benefit in the affected area,
- The SHR Facility emissions must not contribute to nonattainment in or interfere with maintenance of an ambient air quality standard in any other state,
- The SHR Facility emissions must not interfere with any other states implementation plan for prevention of significant deterioration or for protection of visibility.

These conditions will all be met by the SHR Project due primarily to the same measures cited above under reasonable further progress. CRA's displaced generation analysis estimates reductions of up to 8%

throughout ISONE for NO_x, 17% throughout ISONE for SO_2, and reductions for other criteria pollutants. Note that SO_2 emissions can contribute to regional visibility impairment.

8.5 Additional Conditions for Approval

Additional conditions are required for approval under Appendix A. In summary, these are:

- All major stationary sources in Massachusetts owned or operated by the applicant subject to federally enforceable emission limits must be in compliance or on a compliance schedule. Footprint Power does not own or operate any other major sources in Massachusetts.
- Through analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed facility, the applicant must demonstrate to the satisfaction of the MassDEP that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of the facility location and construction. This demonstration is comprised of analyses Footprint Power has made and presented in several places in this application and in other permitting documents submitted to Massachusetts agencies. Specifically, the detailed control technology analyses presented in Section 5 of this application provide this justification for emissions control techniques. Sections 4, 5, 6, and 8 of the Draft Environmental Impact Report (December 2012) provide analyses and justification of the project with respect to project and site alternatives, construction impacts and mitigation, and operational impacts and mitigation.
- EPA must not determine that the Massachusetts State Implementation Plan (SIP) is not being adequately implemented for ozone. No such determination has been made by EPA.

9.0 NOISE ANALYSIS

As a part of the Salem Harbor Redevelopment Project Comprehensive Plan Approval Application, a noise analysis was conducted. A review of applicable regulations was completed as well as a baseline sound survey to establish existing conditions. Noise generated during Project construction and operation was analyzed and potential impacts at noise sensitive receptors (NSRs) were assessed with respect to the applicable regulations. The subsequent subsection discusses acoustic terminology and metrics used in the analysis.

9.1 Acoustic Terminology and Metrics

The unit of sound pressure is the decibel (dB). The decibel scale is logarithmic to accommodate the large dynamics of sound intensities to which the human ear is subjected. By definition, the decibel corresponds to a logarithmic scale formed by taking 20 times the logarithm (base 10) of the ratio of two sound pressures (L_P): the measured sound pressure divided by a reference sound pressure. The reference sound is 20 dB re μPa (0 dB), the approximate threshold of human perception of sound at a frequency of 1000 Hz. The loudness of a sound is typically reported by equipment manufacturers as the source sound power level (L_W), or the total acoustic power radiated in decibels referenced to 10-12 watts. Sound power ratings are independent of environmental conditions in comparison to received sound pressure levels, which include the effects of propagation and attenuation that occur between the source and receptor.

An inherent property of the logarithmic decibel scale is that the sound pressure levels of two separate sounds are not directly additive. For example, if a sound of 50 dB is added to another sound of 50 dB, the total is a 3-decibel increase (or 53 dB), not an arithmetic doubling to 100 dB. The human ear does not perceive changes in the sound pressure level as equal changes in loudness. Scientific research demonstrates that the following general relationships hold between sound level and human perception for two sound levels with the same or very similar frequency characteristics:

- 1 dBA is the practically achievable limit of the accuracy of sound measurement systems and corresponds to an approximate 10 percent variation in sound pressure. A 1 dBA increase or decrease is a non-perceptible change in sound.
- 3 dBA increase or decrease is a doubling (or halving) of acoustic energy and it corresponds to the threshold of perceptibility of change in a laboratory environment. In practice, the average person is not able to distinguish a 3 dBA difference in environmental sound outdoors.
- 5 dBA increase or decrease is described as a perceptible change in sound level and is a discernible change in an outdoor environment.
- 10 dBA increase or decrease is a tenfold increase or decrease in acoustic energy, but is perceived as a doubling or halving in sound (i.e., the average person will judge a 10 dBA change in sound level to be twice or half as loud).

Environmental sound is typically composed of acoustic energy across a wide range of frequencies, referred to as the frequency spectra; however, the human ear does not interpret the sound level from each frequency as equally loud. To compensate for the physical response of the human ear, the A-weighting filter is commonly used for describing environmental sound levels. A-weighting filters the frequency spectrum of sound levels to correspond to the human ear frequency response (attenuating low and high frequency energy similar to the way people hear sound). Sound levels that are A-weighted to reflect human response are presented as dBA. The A-weighted sound level is the most widely accepted descriptor for community noise assessments. Unweighted sound levels are referred to as linear decibels, dB or dBL.

Sound levels can be measured and presented in various formats. The most common sound metric used in community sound surveys is the equivalent sound level (L_{eq}). The L_{eq} level is the energy averaged, A-weighted sound pressure level that occurs over a given time period, *i.e.*, the steady, continuous sound level which has the same acoustic energy as the time-varying sound levels over the same time period. The L_{eq} has been shown to provide both an effective and uniform method for comparing time-varying sound levels and is routinely employed. Community sound levels are also often described in terms of the "day-night" averaged sound level (L_{dn}), which accounts for the increased potential for annoyance that comes with elevated sound levels at night. In addition, the maximum sound level (L_{max}) can be used to quantify the maximum instantaneous sound pressure level generated by a source and is often used in establishing regulatory noise limits. Statistical levels help further characterize the sound environment. The percentile sound levels ($L_{\%}$) indicate the sound level exceeded for that percentage of the measurement period. The L_{90} level is commonly referred to as the background sound level as it excludes short-term intrusive noise events so it is effective in defining the quietest periods. The L_{90} is the statistical level that is exceeded during 90 percent of the measurement period. In comparison, the L_{10} is referred to as the intrusive level and is the sound level that is exceeded for 10 percent of the time during the measurement.

The noise metrics defined are broadband, *i.e.*, inclusive of sound across the entire audible frequency spectrum. In addition to broadband, sound level data typically include an analysis of the various frequency components of the sound spectrum to determine the potential for tonal characteristics and for use in identifying candidate noise mitigation measures. The unit of frequency is Hertz (Hz), measuring the cycles per second of the sound pressure waves, and typically the frequency analysis examines eleven octave bands from 16 Hz (low) to 16,000 Hz (high).

Estimations of common noise sources and outdoor acoustic environments, and the comparison of relative loudness are presented in Table 9-1.

Table 9-1 Sound Pressure Levels and Relative Loudness of Common Noise Sources and Soundscapes

Noise Source or Activity	Sound Level (dBA)	Subjective Impression	Relative Loudness (perception of different sound levels)
Jet aircraft takeoff from carrier (50 ft)	140	Threshold of pain	64 times as loud
50-hp siren (100 ft)	130		32 times as loud
Loud rock concert near stage Jet takeoff (200 ft)	120	Uncomfortably loud	16 times as loud
Float plane takeoff (100 ft)	110		8 times as loud
Jet takeoff (2,000 ft)	100	Very loud	4 times as loud
Heavy truck or motorcycle (25 ft)	90		2 times as loud
Garbage disposal Food blender (2 ft)	80	Loud	Reference loudness
Vacuum cleaner (10 ft)	70		1/2 as loud
Passenger car at 65 mph (25 ft)	65	Moderate	
Large store air-conditioning unit (20 ft)	60		1/4 as loud
Light auto traffic (100 ft)	50	Quiet	1/8 as loud

Noise Source or Activity	Sound Level (dBA)	Subjective Impression	Relative Loudness (perception of different sound levels)
Quiet suburban area	45		
Bedroom or quiet living room Bird calls	40	Faint	1/16 as loud
Typical wilderness area	35		
Quiet library, soft whisper (15 ft)	30	Very quiet	1/32 as loud
Wilderness with no wind or animal activity	25	Extremely quiet	
High-quality recording studio	20		1/64 as loud
Acoustic test chamber	10	Just audible	
	0	Threshold of hearing	

9.2 Environmental Noise Regulations

The criteria for the Project noise analysis are thresholds established by guidelines or regulations at the federal, state, or local level.

9.2.1 Federal Noise Guidelines

The EPA identifies safe levels of environmental noise exposure in a document intended to "provide State and Local governments as well as the Federal Government and the private sector with an informational point of departure for the purpose of decision making."[5] While the EPA has no regulation governing environmental noise, the agency has conducted several extensive studies to identify the effects of sound level on public health and welfare. This publication remains the authoritative study based on a large sampling of community reaction to noise. The EPA sound level guidelines do not provide an absolute measure of noise impact, but rather a consensus on potential activity interference, human health and welfare effects, and annoyance. Since these protective levels were derived without concern for technical or economic feasibility, and contain a margin of safety to ensure their protective value, they should not be viewed as standards, criteria, regulations, or goals. Rather, EPA has stated that they should be viewed as levels below which there is no reason to suspect that the general population will be at risk from any of the identified effects of noise.[6]

The EPA recommends that sound levels outdoors in *residential* areas, and in other places in which quiet is a basis for use, not exceed a day night sound level (L_{dn}) of 55 dBA in order to "protect the public health and welfare with an adequate margin of safety," the standard set out in the Noise Control Act of 1972.[7] The EPA also suggests an L_{eq} of 70 dBA (24-hour) limit to avoid adverse effects on public health and safety at publicly accessible property lines or extents of work areas where extended public exposure is possible.[8] These levels are identified as desirable to protect against speech interference and sleep disturbance for residential, educational, and healthcare areas.

[5] U.S. EPA, *Information on Levels of Environmental Noise Requisite to Protect the Public Health and Welfare with an Adequate Margin of Safety*, Document EPA-550/9-74-004, March, 1974. ("Document EPA-550/9-74-004")
[6] Document EPA-550/9-74-004, at 4.
[7] *Id.*, Noise Control Act of 1972, 42 USC 4904(a)(2).
[8] That is, to protect against hearing damage, one's 24-hour noise exposure should not exceed 70 dBA.

9.2.2 State Noise Policy

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

DEP's regulations at 310 CMR 7.10 prohibit "unnecessary emissions" of noise. DEP Division of Air Quality Control Policy Statement 90-001 (February 1, 1990) (the "DEP Noise Policy") interprets a violation of this noise regulation to have occurred if the source causes either:

- An increase in the broadband sound pressure level of more than 10 dBA above the ambient, or
- A "pure tone" condition.

"Ambient" is defined as the background A-weighted sound level that is exceeded 90% of the time, measured during equipment operating hours (L_{90}). A "pure tone" condition occurs when any octave band sound pressure level exceeds both of the two adjacent octave band sound pressure levels by 3 dB or more.

These noise limits are DEP policy and are applicable both at the facility property line and at the nearest residences. As a policy and not regulation, the DEP has waived these limits in certain cases at property line locations where the adjacent land uses are not considered noise sensitive, such as an adjacent industrial parcel.

9.2.3 City of Salem Code of Ordinances

The City of Salem provides guidance on noise control in Chapter 22 of the Code of Ordinances. Section 22-1 states:

> *"It shall be unlawful for any person to make, continue, or cause to be made or continued any loud, unnecessary or unusual noise or any noise which:*
>
> - *Endangers or injures the safety or health of humans or animals;*
> - *Annoys or disturbs a reasonable person of normal sensitivities; or*
> - *Endangers or injures personal or real property, which noise shall be termed a "noise disturbance" for the purposes of this chapter."*

No numerical sound limits are prescribed in the City's noise ordinance. Section 22-2(5) sets out certain restrictions on construction including restrictions on construction activities which cause sound that "creates a noise disturbance across a residential property boundary" during the hours of 5:00 p.m. to 8:00 a.m. the following day, Monday through Saturday and anytime on Sunday or holidays unless a special variance is obtained by the building inspector. Thus, construction is allowed without a variance between the hours of 8:00 a.m. and 5:00 p.m. Mondays through Saturdays, and at other times if it does not create a noise disturbance on residential property. The same restrictions are imposed on the operation of drilling and/or blasting equipment, rock crushing machinery, pile driving or jack hammers used in construction. Special variances can also be granted by the building inspector for work on Sundays or holidays with the prior approval of the City Council.

9.3 Existing Conditions

As described above, the Project site is bordered by water to the east with some other industrial and recreational land uses in its vicinity as well. There are residences immediately to the west of the site along Fort Avenue and Derby Street and Bentley Elementary School is also located close by. In order to characterize the existing acoustic environment within the Project study area a baseline sound survey was completed in May and November of 2012.

9.3.1 Baseline Sound Survey

Field surveys were conducted of existing environmental sound levels in the vicinity of the Site in order to establish the existing acoustic environment. The analysis area is representative of areas that could be potentially affected by construction or operational noise resulting from the Project. It is expected that the National Grid substation transformers will remain operating at the site even after the existing facility has been demolished; therefore, the transformers have been and will continue to be part of the existing acoustic environment within the Project study area. Since it is a part of the existing and future soundscape, sound survey measurements include baseline sound levels which include operation of these transformers. The sound measurement program consisted both of a combination of short-term and long-term measurements near the property line and at NSRs as discussed further below.

The ambient sound measurement program included both automated unattended long-term measurements ("LT"; 2 weeks) and short-term measurements with an engineer present ("ST"; minimum 30 minute duration). Long-term measurements were made at two locations near the property line for a period of 17 days from April 9 to April 25, 2012 to document diurnal variation. The locations of these two long-term measurement locations were selected to provide a secure location that is representative of the nearby residential areas for characterizing the variation of ambient sound pressure levels. Field-recalibration and data download occurred midway through the LT program. The long-term measurements were used in part to confirm relevant measurement periods to be targeted for the offsite survey periods. Off-site data consisted of short-term ambient sound level measurements, which are consistent with generally accepted data collection procedures to document existing ambient conditions for assessing compliance with the DEP Noise Policy. Short-term measurements were conducted at nine locations beginning on May 17, 2012 and ending early on May 18, 2012. Additional short-term measurements were conducted beginning on November 20, 2012 and ending on November 21, 2012. Additional nighttime measurements were collected at two of the locations (ST-3 and ST-7) monitored in May. In addition, new daytime and nighttime measurements were conducted at three new locations. The short-term ambient sound measurements were taken within what is considered typical daytime hours and nighttime hours.

Measurements were taken with a Larson Davis 831 real-time sound level analyzer equipped with a PCB model 377B02 1/2" precision condenser microphone. This instrument has an operating range of 5 dB to 140 dB, and an overall frequency range of 8 to 20,000 Hz, and meets or exceeds all requirements set forth in the American National Standards Institute standards for Type 1 sound level meters for quality and accuracy/precision. All instrumentation was laboratory calibrated within the previous 12-month period.

In all cases, the microphone and windscreen were tripod-mounted at an approximate height of 1.5 to 1.7 meters (4.9 to 5.6 feet) above grade away from effects of ground level noise and reflective surfaces. In addition, the sound level analyzer microphones were protected from wind-induced self-noise effects by a 180-millimeter (7 inch) diameter foam windscreen made of specially prepared open-pored polyurethane. Each sound analyzer was programmed to measure and log broadband A-weighted sound pressure levels in

10- and 1-minute time intervals, including a number of statistical parameters such as the average (L_{eq}) maximum (L_{max}), and statistical sound levels (L_{10}, L_{50}, and L_{90}). Of these, the residual L_{90} levels are the most meaningful because the residual L_{90} levels are the primary metric used in determining compliance with the DEP Noise Policy for operational noise. Data were collected for 1/1 and 1/3 octave bands spanning the frequency range of 8 Hz to 20 kHz. Following the completion of the measurement period, all measured data were downloaded to a computer for the purposes of storage and further analysis.

Atmospheric conditions during the short-term survey period were conducive for the collection of accurate sound measurements. Ambient temperatures ranged from 45°F to 82°F and fair conditions prevailed with generally light winds. There was no precipitation during the ST monitoring periods and area roadways were dry. A graphical record of the general weather parameters during long-term measurements as observed in Beverly just to the north of the project area is shown in Figure 9-1.

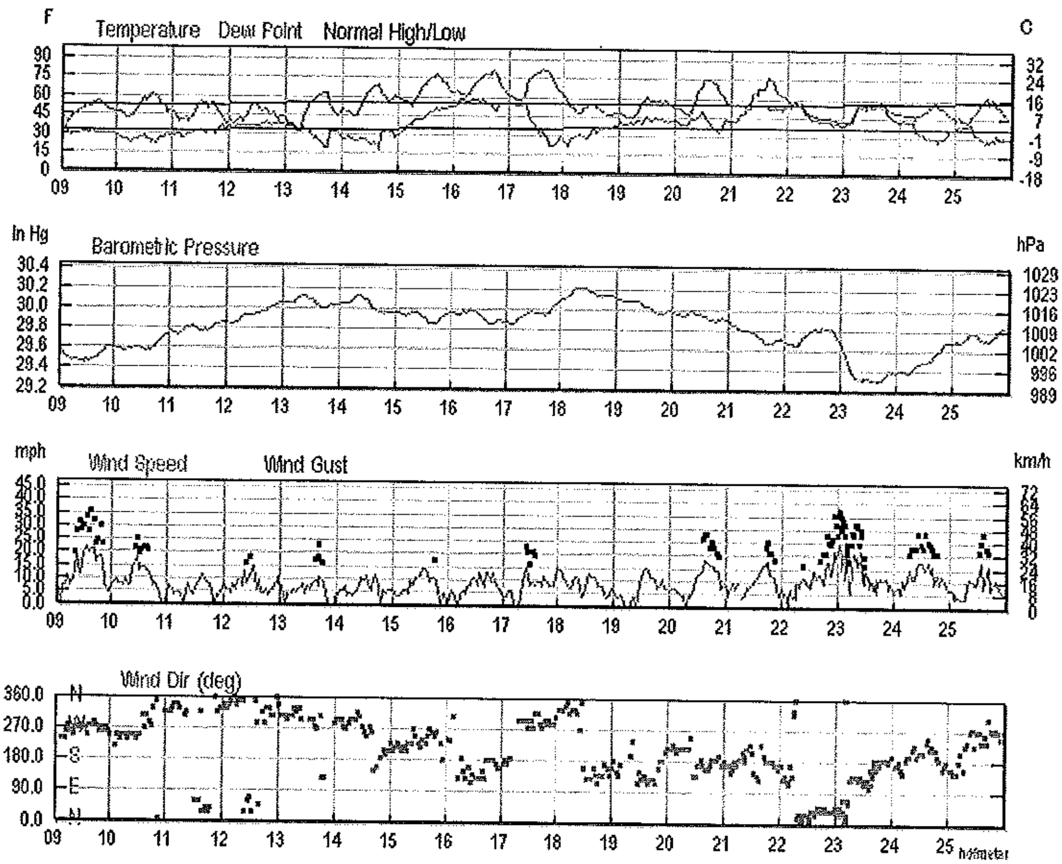


Figure 9-1 **Weather Conditions during Sound Level Survey Period as Observed in Beverly, MA.**

9.3.2 Sound Measurement Locations and Results

The sound measurement locations are shown in Figure 9-2. The measurement locations, times, and existing sound sources observed during the survey are as follows:

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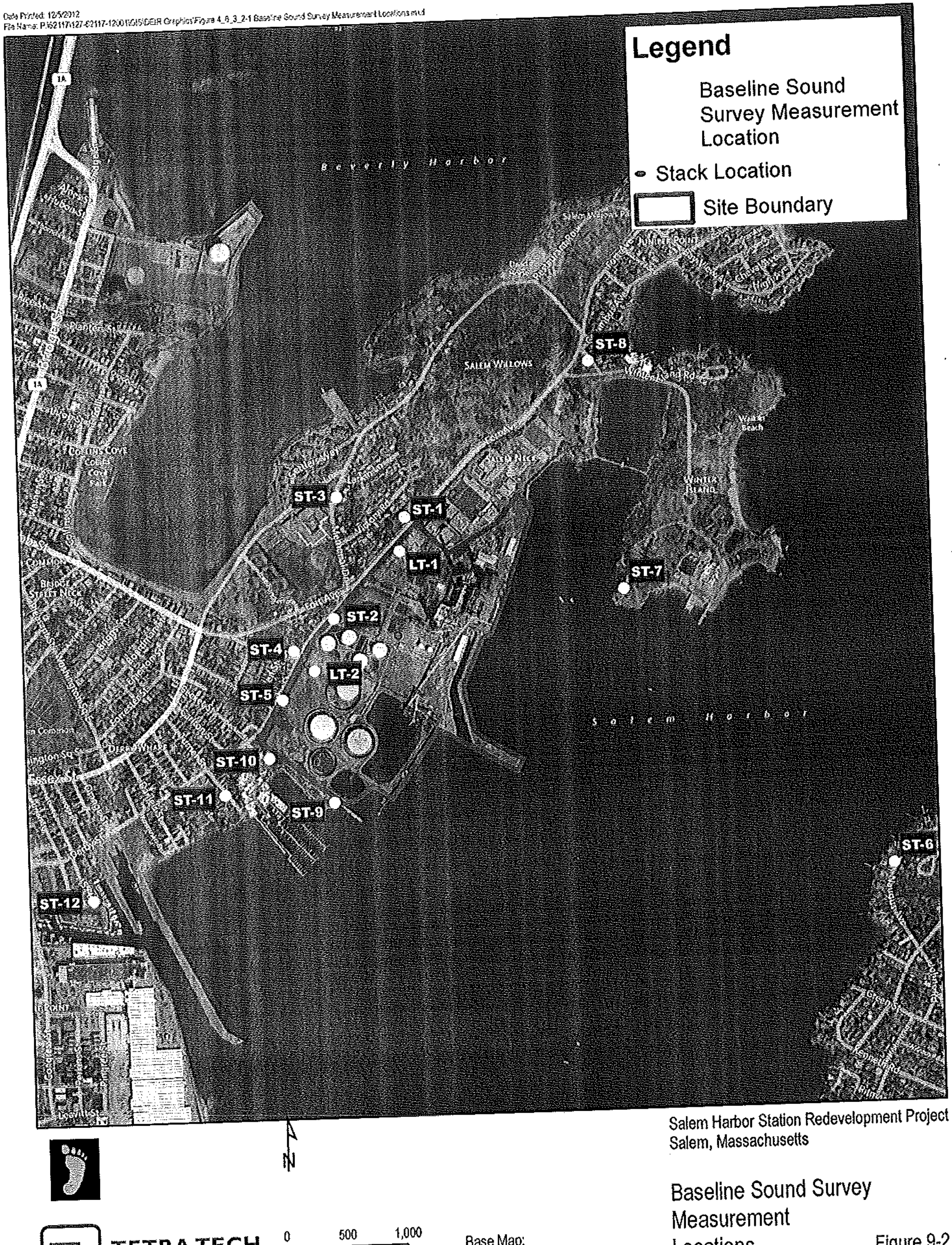
File Name: P:\62117\127-62117-1200\GIS\DEIR Graphics\Figure 4_6_3_2-1 Baseline Sound Survey Measurement Locations.mxd



Salem Harbor Station Redevelopment Project
Salem, Massachusetts

TETRA TECH

Base Map: Bing

Baseline Sound Survey Measurement Locations

Figure 9-2

- **ST-1:** Located near 39 Fort Avenue, which represents residences located to the north, across the street from the proposed CCG Facility. Daytime measurements were taken from approximately 1:30 p.m. to 2:00 p.m. on May 17 and nighttime measurements were taken from approximately 10:55 p.m. to 11:25 p.m. that same day. Existing sound sources noted during short-term measurements included nearby traffic (cars, motorcycles, mopeds), low-level noise from the existing facility, railway movement, and a couple of instances of aircraft over-flights.
- **ST-2:** Located at the property line to the west, near residences at the intersection of Fort Avenue and Derby Street, close to the entrance to the Salem Harbor Power Station. Measurements were taken from approximately 2:20 p.m. to 2:50 p.m. on May 17 and from 11:25 p.m. on May 17 to 12:05 a.m. on May 18. Traffic on Fort Avenue contributed to sound at this location. Other contributors included the hum of Salem Harbor Station transformers, natural sounds (wind, birds), and other sound sources such as a police siren and firecrackers in the distance.
- **ST-3:** Located to the northeast at the Bentley Elementary School on 25 Memorial Drive. Daytime monitoring was conducted during the period between 11:50 a.m. and 12:20 p.m. on May 17. Nighttime monitoring was conducted on the southeast sidewalk of the school during the period between 1:00 a.m. and 1:30 a.m. on November 21. Daytime sound sources included consistent traffic during the monitoring period, which was the predominant contributor to sound levels at the school. Nighttime sound sources included a low hum from the existing Salem Harbor Station and/or National Grid Substation and nearby traffic.
- **ST-4:** Located at the property line to the southwest of ST-2, near residences at the intersection of Webb Street and Derby Street, close to 23 Derby Street. Daytime measurements were taken from approximately 3:25 p.m. to 3:55 p.m. on May 17 and nighttime measurements were taken from approximately 12:00 a.m. to 12:30 a.m. on May 18. Traffic, consisting of cars, motorcycles, and trucks, was steady during daytime hours with significantly fewer vehicles observed during the nighttime period.
- **ST-5:** Located at the property line to the southwest, close to residences and adjacent to 59 Derby Street. This location is near the southern boundary of the proposed site with testing occurring from approximately 2:30 p.m. to 3:00 p.m. and again from approximately 11:25 p.m. to 11:55 p.m. on May 17. Contributors to sound were similar to those identified at ST-4.
- **ST-6:** Located to the east, across Salem Harbor from the Station opposite the residence at 76 Naugus Avenue in Marblehead. Daytime measurements were taken from approximately 10:30 a.m. to 11:00 a.m. on May 17 and nighttime measurements were taken from approximately 10:35 p.m. to 11:05 p.m. that same day. Sound sources heard during the measurement periods included road traffic, railway movement, and an aircraft over-flights.
- **ST-7:** Located to the east, at the Winter Island Park Harbormaster Office. Winter Island Park is a recreational area. Measurements were taken on May 17 during daytime hours between 12:40 p.m. and 1:10 p.m. Nighttime monitoring was conducted during the period between 12:00 a.m. and 12:30 a.m. on November 21. Existing daytime sound sources in and around ST-7 consisted of periodic vehicle passbys and natural sounds. Nighttime sound sources included a periodic flushing sound from the South Essex Sewerage District, distant church bells, and sound from the nearby Hawthorne Cove Marina.
- **ST-8:** Located slightly northeast of the site near the intersection of Fort Avenue and Winter Island Road. Daytime measurements were taken from approximately 12:45 p.m. to 1:15 p.m. on May 17 and nighttime measurements were taken from approximately 11:20 p.m. to 11:50 p.m.

that same day. Existing sound sources noted during short-term measurements included nearby traffic, natural sounds (wind, birds), some sound from the Salem Harbor Station, rail movement, and an aircraft overflight.

- **ST-9**: Located on the property line of the Salem Harbor Station, to the south at Blaney Street Pier on Salem Wharf. This location was selected for daytime measurements only during the period from 1:50 p.m. to 2:20 p.m. on May 17 because there are no residents represented by this location. Sound sources included activities at the nearby marina and on the pier and periodic motor vehicle movements in the vicinity of the measurement locations.
- **ST-10**: Located at the Mackey Building/Art Gallery near the southwest corner of the property. Daytime measurements were taken on November 20 between 1:05 p.m. and 1:40 p.m. Nighttime monitoring was conducted on November 21 during the period between 3:15 a.m. and 3:45 a.m. Daytime sound sources included activities such as traffic at the nearby Hawthorne Cove Marina, intermittent construction equipment at the Ferry Terminal, and natural sources such as birds. Nighttime sound sources included one car on Derby Street and some noise generated by halyard movement at the Hawthorne Cove Marina.
- **ST-11**: Located on the sidewalk near the House of Seven Gables across from 41 Turner Street. Daytime measurements were taken on November 20 between 1:50 p.m. and 2:30 p.m. Nighttime monitoring was conducted on November 21 during the period between 2:30 a.m. and 3:00 a.m. Daytime sound sources included activities at the Hawthorne Cove Marina, traffic on nearby Derby Street, periodic human and motor traffic, nearby maintenance activities, a distant airplane, and natural sources such as birds. There were no perceptible noise sources observed during the nighttime measurement period.
- **ST-12**: Located at Pickering Wharf near Victoria's Station approximately 100 feet behind the Sail Schooner "Fame" kiosk. Daytime measurements were taken on November 20 between 3:20 p.m. and 3:55 p.m. Nighttime monitoring was conducted on November 21 during the period between 1:45 a.m. and 2:15 a.m. Daytime traffic was observed including vehicular, human traffic, and 1 boat. Other daytime sound sources included construction activities near Friendship schooner on Derby Wharf. Nighttime sound sources included human and vehicle traffic, and a slight hum from the direction of the National Grid Substation.
- **LT-1**: This location lies within the property of the Salem Harbor Station and represents the proposed facility boundary within the northern section of the site. Continuous long-term measurements were taken for a period of approximately 16 days starting on April 9 and concluding on April 25, 2012.
- **LT-2**: This location lies within the property of the Salem Harbor Station and represents the proposed facility boundary within the southern section of the site. Continuous long-term measurements were taken for a period of approximately 16 days starting on April 9 and concluding on April 25, 2012.

The long term measurements indicate that there is no significant difference between weekend night and weekday night noise levels. In addition, the measurement data support the position that minimum nighttime sound levels (representative of the controlling receptors) were observed to be generally consistent over the course of the 17-day measurement period. This conclusion may be due to the traffic as a primary contributor to ambient sound levels, which is generally present throughout the year. Therefore, with the exception of unusual high traffic events or clearly abnormal circumstances, it is reasonable to expect a nighttime level of traffic throughout the year that is generally consistent with the conditions present during the baseline measurement program. Figure 9-3 and Figure 9-4 show time history plots of L_{eq}, L_{10}, L_{50}, and L_{90} values for LT-1 and LT-2, respectively.

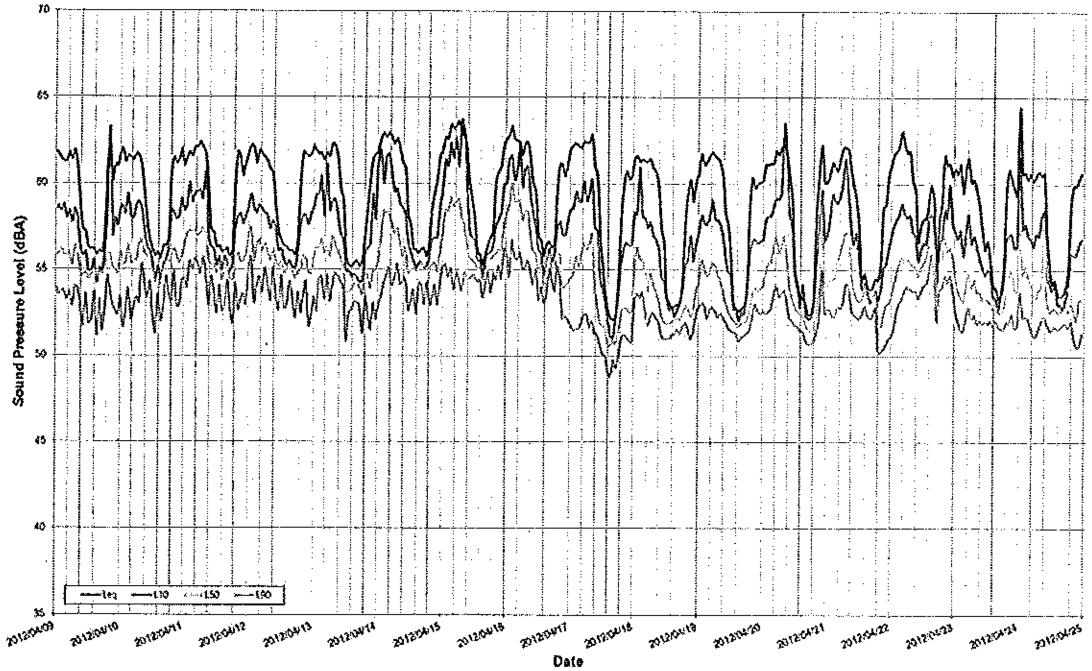


Figure 9-3 LT-1 Time History Plot of L10, L50, L90 and Leq Sound Pressure Levels

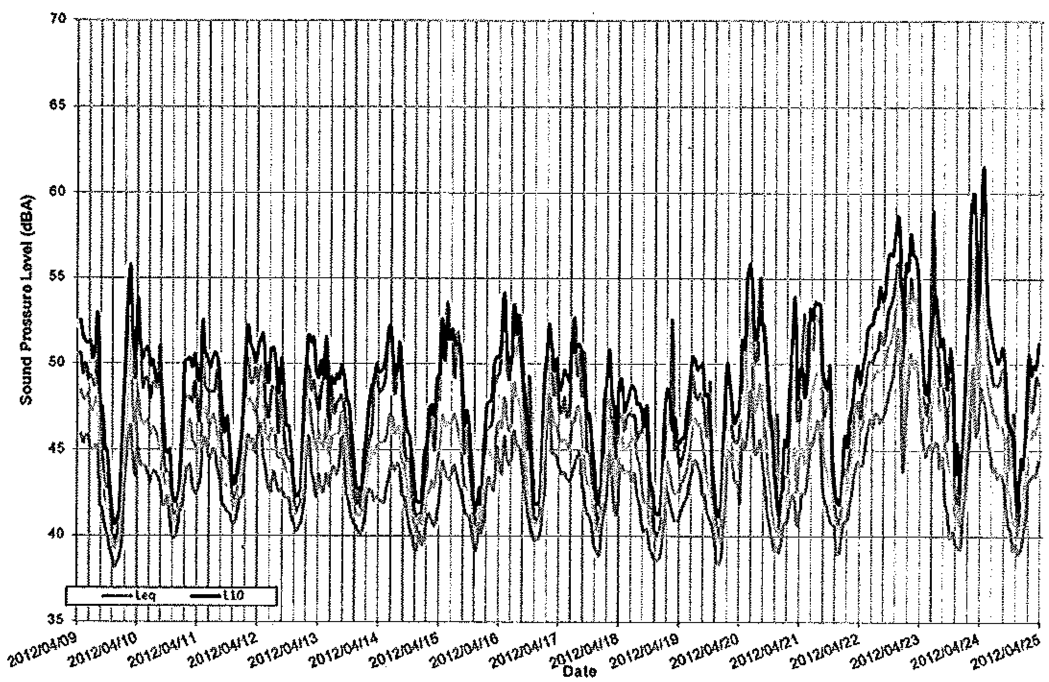


Figure 9-4 LT-2 Time History Plot of L10, L50, L90 and Leq Sound Pressure Levels

Baseline sound levels were higher at ST-1 and ST-2 due to traffic-related noise and possibly noise from the Salem Harbor Station, National Grid Substation, and/or SESD wastewater treatment facility. Ambient sound levels at ST-4 and LT-2 are relatively similar, which is expected since they were located relatively close to one another. The lowest ambient nighttime sound levels were exhibited at ST-6 and ST-10, which are located farther away from the proposed project site. Sound generated from existing facility operations may have also contributed to measurements collected at long-term monitoring locations. A review of operating parameters provided by the existing facility during the measurement program indicate that, during long-term measurement, Unit 3 was operating at an average gross 38 MW rating through April 16, with power production increasing to an average gross 66 MW rating through April 18. After April 18 and for the duration of the long-term monitoring period, there was no power production equipment in operation. During short-term measurement the existing facility was not generating electricity.

Table 9-2 summarizes the results of the short-term and long-term measurements. For each monitoring location the following data are provided: the corresponding Universal Transverse Mercator (UTM) coordinates; the distance to the site, specifically to the main stack; and the average daytime and nighttime L_{eq}, L_{10}, L_{50}, and L_{90} values. For LT-1 and LT-2, the reported sound level metric represents the average over the entire daytime and nighttime periods during the 17 day monitoring period.

Table 9-2 Updated Summary of Daytime and Nighttime Baseline Measurement Results - Sound Level Metrics

Monitoring Location			Time Period	Sound Level Metrics (dBA)			
ID	UTM Coordinates (NAD83 UTM Zone 19N) Easting	Northing		L_{eq}	L_{10}	L_{50}	L_{90}
ST-1	345770	4710123	Day	57	60	54	51
			Night	54	56	50	49
ST-2	345577	4709881	Day	57	61	51	47
			Night	50	51	46	44
ST-3	345602	4710183	Day	51	53	49	46
			Night	44	43	40	39
ST-4	345472	4709808	Day	56	60	50	45
			Night	44	47	40	39
ST-5	345436	4709687	Day	55	58	51	47
			Night	44	46	42	41
ST-6	346948	4709190	Day	50	52	49	47
			Night	40	41	39	38
ST-7	346309	4709911	Day	49	50	48	47
			Night	41	42	40	39
ST-8	346255	4710481	Day	52	56	50	46
			Night	48	51	43	40
ST-9	345551	4709427	Day	42	44	40	39
			Night	N/A	N/A	N/A	N/A
ST-10	345395	4709545	Day	60	58	52	50
			Night	39	40	37	36
ST-11	345280	4709461	Day	50	51	45	42

Tt

Monitoring Location				Sound Level Metrics (dBA)			
	UTM Coordinates (NAD83 UTM Zone 19N)						
ID	Easting	Northing	Time Period	L_{eq}	L_{10}	L_{50}	L_{90}
			Night	40	41	40	39
ST-12	344934	4709219	Day	48	50	46	44
			Night	43	44	42	41
LT-1	345751	4710039	Day	58	61	56	53
			Night	55	56	54	53
LT-2	345520	4709755	Day	49	50	47	44
			Night	44	46	43	41

9.4 Construction Sound Assessment

Construction of the Project will result in a temporary increase in sound levels near the site. The construction process will require the use of equipment that will be audible from off-site locations during certain time periods. Project construction consists of site clearing, excavation, foundation work, steel erection, and finishing work. Work on these phases will overlap. Pile driving, generally considered the loudest construction activity may also be required during the excavation phase to provide proper structural support for the turbine building foundation. No blasting would be performed on the site. Construction of the facility, from mobilization through site preparation and grading, to commercial operation, is expected to begin in June 2014 and continue for a period of 23 months.

The noise levels resulting from construction activities vary greatly depending on such factors such as the type of equipment, the specific equipment model, the operations being performed, and the overall condition of the equipment. Since specific information on types, quantities, and operating schedules of construction equipment is not available at this point in project development, information from reference documents based on construction projects were used[9,10]. The U.S. Environmental Protection Agency has published data on the average (L_{eq}) sound levels for typical construction phases. Use of this data, which is over 20 years old, is expected to be somewhat conservative since the evolution of construction equipment has been toward quieter designs to protect operators from exposure to high noise levels. In addition, Federal Highway Administration construction noise data show pile driving typically produces an average (L_{eq}) sound level of 91 dBA and a peak (L_{max}) sound level of 98 dBA; both values are at a reference distance of 50 feet. Sound levels were projected to a distance of 500 feet which is the average distance of most construction activities to the closest residential receptor. These results are conservative since the only attenuating mechanism considered was divergence of the sound waves in open air. Shielding effects of intervening structures and terrain were not included in the calculations. Actual received sound levels will fluctuate, depending on these factors and others including equipment type, and separation distances between source and receiver.

Table 9-3 summarizes results for five construction phases at the closest residences and the Bentley Elementary School. The results of these calculations show construction sound levels at the nearest

[9] Barnes, J.D., L.M. Miller, and E.W. Wood, 1976 Power Plant Construction Noise Guide. BBN Report No. 3321
[10] Environmental Protection Agency, Noise from Construction Equipment and Operations, Building Equipment and Home Appliances, NTID-200.1, 1971.

residential locations on Derby Street would in most instances be between 60 and 70 dBA. Table 9-3 results do not assume any specific noise mitigation measures or any noise limits for the contractor.

Table 9-3 Equivalent Noise Levels by Construction Phase at Closest Noise Sensitive Areas

Construction Phase	EPA Construction Noise Level 50 ft	Closest Residences[1] 500 ft	Bentley Elementary School* 1000 ft	Bentley Elementary Fields[1] 620 ft
	Leq, (dBA)			
Ground clearing	84	64	58	62
Excavation	89	69	63	67
Foundations and concrete pouring	78	58	52	56
Steel erection	85	65	59	63
Mechanical	81	61	55	59
Finishing Work	89	69	63	67

[1]Noise levels at limited times during these phases may exceed the noise levels presented as some equipment locations may be closer than the distances presented.

The City of Salem Code of Ordinances governs construction noise, setting forth requirements on construction hours, allowable activities, and procedures for obtaining a special variance during times when certain construction activities are not allowed. The contractor will adhere to all requirements of the ordinance and obtain special variances, if necessary. No decibel limits apply to construction activity.

Pile driving on the site would be restricted to daytime periods only, and none would occur on Sundays. Pile driving typically produces a maximum sound level of 98 dBA L_{max} at 50 feet. The estimated instantaneous maximum (L_{max}) sound level at the nearest residential receptor is 78 dBA. To mitigate pile driving sound, the Project will explore the feasibility of installing support piles with an auger drill and crane, a quieter pile placement technique that is possible with certain soil and geological conditions.

Even though construction noise is not regulated under the State regulations and the City of Salem noise ordinance, every reasonable and feasible effort will be made to minimize construction noise to avoid disturbing nearby residential and other sensitive receptors. Towards that end, the contractor will be required to develop a Construction Noise Management Plan demonstrating adherence to Best-Management-Practices aimed at reducing construction noise levels and ensuring compliance with EPA guideline levels and OSHA regulatory health and safety limits at all residences. Construction activities generating noise will normally be limited to daytime construction hours Monday through Friday, but extended hours may be necessary occasionally for certain activities.

9.5 Operational Sound Assessment

Calculations of operational noise impacts were calculated using DataKustic GmbH's CadnaA, the computer-aided noise abatement program (v 4.1.137). CadnaA conforms to International Standard ISO-9613.2, "Acoustics – Attenuation of Sound during Propagation Outdoors." The method evaluates A-weighted sound pressure levels under meteorological conditions favorable to propagation from sources of known sound emissions. The calculation of sound propagation from source to receiver locations consists of algorithms that incorporate the following physical effects:

- Geometric spreading wave divergence
- Reflection from surfaces
- Atmospheric absorption
- Screening by topography and obstacles
- Terrain complexity and ground effects
- Sound power at multiple frequencies
- Source directivity factors
- Multiple noise sources and source type (point, area, and/or line)
- Height of both sources and receptors
- Averaging predicted sound levels over a given time period

In addition to geometric distance attenuation and atmospheric air absorption effects, the absorptivity of the ground surface is a significant propagation loss factor that is calculated by the program. Ground absorption is calculated using a coefficient ranging from 0 to 1, where 0 would be the characteristic of a hard surface like pavement and 1 would represent acoustically soft ground such as grassy residential yards. The ground attenuation selected was semi-reflective for all offsite areas, and hard reflective for all onsite paved areas and bodies of water. Offsite topography was determined using official USGS digital elevation data for the study area.

The model input involves evaluating individual facility component noise sources representing each piece of equipment that produces a significant amount of noise. A three-dimensional rendering of the facility was created directly from the preliminary site plan drawing by defining the height and extent of all significant noise sources. Sound power levels were assigned to each source in a manner that best represents their expected acoustic performance and geometric dimensions. For example, building walls are defined as vertical area sources and smaller sources such as pumps are defined by individual point sources.

9.5.1 Project Sound Sources

Source level assumptions used in the modeling analysis for the sound-generating equipment during Project operations were derived from a combination of manufacturer specifications, engineering and technical guidelines. Several design elements will be necessary to control noise emissions and will be employed to meet the project noise limits. The Project noise sources that were evaluated are as follows:

- Main exhaust stack
- Air-cooled condenser
- Gas turbine power train package
- Gas turbine air inlets
- Steam turbine power train package
- HRSG package – low noise design
- CTG step-up transformers

- STG GSU transformer
- Screw-type gas compressor
- Gas metering station
- Auxiliary boiler stack
- Auxiliary cooling system cooling tower

The noise emissions from the facility have been calculated at the residential and other potential noise sensitive receptors of concern. The noise levels presented represent the anticipated steady-state level from the Project with essentially all equipment operating.

9.5.2 Project Sound Mitigation Measures

As with any large, complex project, the information available during the initial engineering phases is only at a conceptual level and does not allow design details to be finalized for specific mitigation measures. Vendor information has been incorporated into the Project's acoustical model when available. Final design will incorporate appropriate mitigation measures to ensure compliance with all applicable regulatory requirements. These measures may include acoustical enclosures, barriers, silencers, and lagging, in addition to procuring low noise equipment. For the acoustic modeling analysis the following noise mitigation options were incorporated into the Project's conceptual design:

- The main exhaust stack flues will each be outfitted with an inline silencer;
- An air-cooled condenser with low noise fans will be employed as well as the use of sound-attenuating baffles for the inlet and discharge of the condenser;
- The HRSG structure walls will be treated with acoustically-treated, absorptive materials;
- The gas turbine air inlet ducting will include internal sound attenuating baffles and the entire air inlet filter/evaporative cooler assembly will be enclosed using sound absorbing materials for the siding and roofing;
- The steam turbine generator will be located indoors and the building will incorporate acoustically-treated, absorptive materials;
- Reduced noise transformers will be used and enclosed with firewalls/barriers;
- The fuel gas compressors will be fully enclosed inside a building; and
- A retaining wall and berm, which surrounds the majority of the Project site, will be included.

Based on final design changes and the requirement that vendors/manufacturers meet target limits, the above noise mitigation measures will likely undergo revision.

9.5.3 Acoustic Modeling Results

With the principal noise minimization and mitigation measures installed as described in Section 9.5.4, the predicted maximum sound level impacts at the various receptors were added to the lowest nighttime L_{90} levels (from Table 9-2) to determine the potential increase and to assess conformance with DEP's Noise Policy. As shown in Table 9-4, the Project will increase the lowest background sound levels by <1 to 6 dBA at the nearest noise sensitive receptors in Salem and Marblehead. These potential increases in background sound levels apply during nighttime hours. During daytime hours, when background L_{90} levels are higher than the nighttime minimums, net increases are expected to be less.

Table 9-4 Cumulative Environmental Noise Levels during Base Load Operation in dBA

Receptor	Background/Ambient	SHR Facility	Total	Increase Over Background
1. 22 Fort Avenue	49	44	50	1
2. Block House Square/Derby Street	44	44	47	3
3. Bentley Elementary School	39	42	44	5
4. 36 Derby Street	39	44	45	6
5. 56 Derby Street South	41	44	46	5
6. 79 Naugus Avenue (Marblehead)	38	25	38	0
7. Winter Island Park	39	39	42	3
8. Winter Island Road	40	33	41	1
9. Blaney Street Pier on Salem Wharf	39	43	44	5
10. Mackey Building/Art Gallery	36	41	42	6
11. House of Seven Gables	39	37	41	2
12. Pickering Wharf	41	30	41	0

9.6 Evaluation of Additional Sound Mitigation Measures

The proposed sound mitigation measures discussed in Section 9.5.2 above represent a highly mitigated design for a combined cycle power generation facility. The "low noise" options for various equipment will be used, and the ACCs in particular incorporate significant silencing and low noise features. Therefore, there is not an extensive list of additional sound mitigation measures that are potentially meaningful to evaluate. Two additional sound mitigation options that have been evaluated are as follows:

- Increase the length of the gas turbine air inlet silencers from 12 feet to 16 feet.
- Install a roof over the HRSG structures

With respect to increasing the length of the gas turbine air inlet silencers from 12 feet to 16 feet, this requires an increase in the air inlet duct lengths to accommodate the additional silencing baffles. The cost of the additional silencer baffles is estimated to be $250,000 per unit, and the inlet air duct length extension is estimated to cost $500,000 to $750,000 per unit for a plant total of $1.5 to $2 million. The additional baffles are expected to increase the pressure drop through the inlet air silencing system by approximately 0.4" w.g., which will decrease the net power generation per unit by approximately 100 kW. The net present value of 100 kW of lost power generation over the life of the units has been conservatively ignored.

With respect to installing a roof over the HRSG structures, these structures currently have walls which extend a sufficient height upwards and are designed to block sound radiating sideways from the HRSGs and related appurtenances. The open roof arrangement allows the HRSG area to cool via natural ventilation and avoids the need for large mechanical roof ventilators which would increase the parasitic load of the plant and decrease the heat rate as well as be an additional source of noise. The total cost of installing roofs over each HRSG structure is estimate to be approximately $5.8 million

CadnaA model calculations have been undertaken to evaluate the noise reductions that would be achieved by either of these two additional noise mitigation measures. Table 9-5 presents these results for the noise receptors in Table 9-4 which have either a 5 or 6 dBA increase over background with the proposed design mitigation measures. The results in Table 9-5 show the resulting decrease in the SHR Project impact on ambient sound levels at the receptors with the greatest SHR Project impact is at most 1 dBA. Therefore, due to the significant investment required for either measure, neither of these additional sound mitigation measures is considered warranted.

Table 9-5 Summary of Additional Sound Mitigation Measures and Costs

Receptor	SHR Project Impact with Proposed Sound Mitigation (dBA)	Resulting Change in Predicted Noise Levels (dBA)	
		Option 1 Increase Air Inlet Silencers From 12' to 16'	Option 2 Install Roof Over HRSG Structures
3. Bentley Elementary School	42	-1	-1
4. 36 Derby Street	44	-1	0
5. 56 Derby Street South	44	0	0
9. Blaney Street Pier on Salem Wharf	43	0	0
10. Mackey Building/Art Gallery	41	-1	-1
Option estimated implementation costs ($)	--	$1,500,000 to $2,000,000	$5,800,000
Selected for Implementation?	--	No	No

9.7 Conclusion

As shown in Table 9-4, sound generated by the proposed Project is expected to comply with the 10 dBA incremental limit in the DEP Noise Policy. Furthermore, field measurements of comparable combined-cycle plants have shown that the frequency spectrum produced by this type of plant is broadband in nature and generally lacking in any prominent or identifiable tones, which are commonly sources of community disturbance. Special attention will be given to sources that do tend to be tonal in nature, in the design and specification of the plant's equipment and take necessary steps to prevent sources from emitting tones that might be disturbing at the nearest receptors. Noise generated during the testing and commissioning phase of the Project is not expected to be substantially different from that produced during normal full-load operation. Starts and abrupt stops are more frequent during this period, but on the whole they are usually short-duration events.

In addition, The potential maximum sound level impacts at the closest noise sensitive locations were compared to the Salem noise ordinance limits to prevent noise that "annoys or disturbs a reasonable person of normal sensitivities" in residentially zoned areas. Project sound levels are in full compliance with the Salem Noise Ordinance.

APPENDIX A

CPA Forms

Enter your transmittal number → X254064
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

1. Permit Code: 7 or 8 character code from permit instructions: BWP AQ 03
2. Name of Permit Category: Major CPA
3. Type of Project or Activity: Combined cycle natural gas electric generating plant

B. Applicant Information – Firm or Individual

1. Name of Firm - Or, if party needing this approval is an individual enter name below: Footprint Power Salem Harbor Development LP
2. **Last Name** of Individual:
3. **First Name** of Individual:
4. MI:
5. Street Address: 1140 Route 22 East, Suite 303
6. City/Town: Bridgewater
7. State: NJ
8. Zip Code: 08807
9. Telephone #: 908-864-4905
10. Ext. #:
11. Contact Person: Scott G. Silverstein
12. e-mail address (optional): ssilverstein@footprintpower.com

C. Facility, Site or Individual Requiring Approval

1. Name of Facility, Site Or Individual: Salem Harbor Redevelopment Project
2. Street Address: 24 Fort Avenue
3. City/Town: Salem
4. State: MA
5. Zip Code: 01970
6. Telephone #: N/A
7. Ext. #:
8. DEP Facility Number (if Known): N/A
9. Federal I.D. Number (if Known): N/A
10. BWSC Tracking # (if Known): N/A

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

1. Name of Firm Or Individual: Tetra Tech
2. Address: 160 Federal Street, 3rd Floor
3. City/Town: Boston
4. State: MA
5. Zip Code: 02110
6. Telephone #: 617-443-7500
7. Ext. #:
8. Contact Person: George Lipka
9. LSP Number (BWSC Permits only): N/A

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: 14937
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: 1031
Dollar Amount: $19,780
Date: 12/18/2012

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)

X254064
Transmittal Number

N/A
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

Salem Harbor Redevelopment Project
1. Facility Name

24 Fort Avenue
2. Street Address

Salem
3. City

MA
4. State

01970
5. ZIP Code

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

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

4911
8. Standard Industrial Classification (SIC) Code

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

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

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

Table 1

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

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

A. Facility Information (continued)

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

If Yes, describe:

B. Equipment Description

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

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

   If Yes, list pertinent Plan Approval(s):

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

   If Yes, list pertinent Plan Approval(s):

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

   Footprint Power Salem Harbor Development LP proposes to construct and operate a nominal 630 megawatt (MW) natural gas-fired, quick-start combined-cycle generating facility at the Salem Harbor power station site in Salem, Massachusetts. See attached cover document for detailed descriptions of the proposed emission units.

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)
TBD	TBD	NOx	0.0	158.6	200

[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)
1 ☒ New ☐ Modified	Siemens SCC6-5000F(5) or GE 107FA.05 with HRSG duct burner* *See footnote of page 2-4 of text	2,452,300,000	Natural gas	None
2 ☒ New ☐ Modified	Siemens SCC6-5000F(5) or GE 107FA.05 with HRSG duct burner* *See footnote of page 2-4 of text	2,452,300,000	Natural gas	None
3 ☒ New ☐ Modified	Cleaver Brooks CBND-80E-300D-65 Boiler or similar	80,000,000	Natural gas	None
4 ☒ New ☐ Modified	Cummins DQFAA Diesel Emergency Generator or similar	7,400,000	Ultra-low-sulfur diesel oil	None

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)).

1. 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)
5 ☒ New ☐ Modified	Cummins CFP9E-F50 Diesel Fire Pump or similar	2,700,000	Ultra-low-sulfur diesel oil	None
☐ New ☐ Modified				
☐ New ☐ Modified				
☐ New ☐ Modified				

B. Equipment Description (continued)

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

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

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?
1	TBD (duct burner)	Included below	Duct burner	☐ Yes ☒ No
2	TBD (duct burner)	Included below	Duct burner	☐ Yes ☒ No
3	Cleaver Brooks, model unknown	81,950 cfh	Ultra-low NOx	☐ Yes ☐ No **TBD**
				☐ Yes ☐ No

3. 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)
1	2,511,000 cfh (w/ duct burner)	see Application text
2	2,511,000 cfh (w/ duct burner)	see Application text

Continue to Next Page ►

B. Equipment Description (continued)

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

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

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?
5	N/A	19.2 gph	N/A	☐ Yes ☒ No
				☐ Yes ☐ No
				☐ Yes ☐ No
				☐ Yes ☐ No

2. 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)

Continue to Next Page ►

B. Equipment Description (continued)

3. 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)
HRSG SCR Catalyst ☒ New ☐ Existing	1, 2	VOC	
		CO	
		PM[1]	
		NO_x	78% nominal
		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	1, 2	VOC	< 25% expected
		CO	84% nominal
		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

4. 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.

5. 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.
1, 2	See Application text	TBD	TBD

B. Equipment Description (continued)

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

   *If No, explain:

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

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

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

   The proposed project has no potential for odor impacts.

C. Stack Description

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

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

Table 8

Emission Unit No.	Stack Height Above Ground (Feet)	Stack Height Above Roof (Feet)	Stack Exit Diameter or Dimensions (Feet)	Exhaust Gas Exit Temperature Range (Degrees Fahrenheit)	Exhaust Gas Exit Velocity Range (Feet per Second)	Stack Liner Material
1	230	105	20	175 to 224	39.2 to 69.1	Steel
2	230	105	20	175 to 224	39.2 to 69.1	Steel
3	125	49	3	up to 530	up to 70.1	Steel
4	86	10	1	up to 620	up to 70.1	Steel

Continue to Next Page ►

B. Equipment Description (continued)

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

   *If No, explain:

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

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

C. Stack Description

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

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

Table 8

Emission Unit No.	Stack Height Above Ground (Feet)	Stack Height Above Roof (Feet)	Stack Exit Diameter or Dimensions (Feet)	Exhaust Gas Exit Temperature Range (Degrees Fahrenheit)	Exhaust Gas Exit Velocity Range (Feet per Second)	Stack Liner Material
5	25	10	1	Up to 820	Up to 36	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. 1, 2 (per unit) Fuel Used Natural gas	PM[1]	N/A	N/A	54.0	N/A	N/A
	$PM_{2.5}$	N/A	N/A	54.0	N/A	N/A
	PM_{10}	N/A	N/A	54.0	N/A	N/A
	NO_x[2]	9 ppmvd @ 15% O2	2 ppmvd @ 15% O2	76.8	N/A	N/A
	CO	12.5 ppmvd @ 15% O2	2 ppmvd @ 15% O2	101.8	N/A	N/A
	VOC	2-2.5 ppmvd @ 15% O2	2 ppmvd @ 15% O2	18.9	N/A	N/A
	SO_2	N/A	N/A	15.6	N/A	N/A
	Max HAP[3]	N/A	N/A	3.6	N/A	N/A
	Total HAPs[3]	N/A	N/A	6.9	N/A	N/A
	NH_3	NA	2 ppmvd @ 15% O2	28.0	N/A	N/A
	CO_2[4]	842 lb/MW net	842 lb/MW net	1,233,952	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] NOx emissions from this proposed project need to be included for the purposes of NOx 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 net MW is based on a "new and clean" net heat rate of 7,080 Btu per kWh delivered to the grid, at base load conditions, and corrected to ISO conditions of 59°F, 14.7 psia, and 60% humidity.

[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.

D. Best Available Control Technology (BACT) Emissions

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

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

Table 9A

Emission Unit No. & Fuel Used	Air Contaminant	Uncontrolled Emissions (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O2 or CO2])	Proposed BACT Emissions (lbs/hr, lb/MMBtu or ppmvd@ %O2 or CO2)	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. 1, 2 (per unit) Fuel Used Natural gas	PM[1]	≤0.0088 lb/MMBtu	≤0.0088 lb/MMBtu	54.0	N/A	N/A
	$PM^1_{2.5}$	≤0.0088 lb/MMBtu	≤0.0088 lb/MMBtu	54.0	N/A	N/A
	PM^1_{10}	≤0.0088 lb/MMBtu	≤0.0088 lb/MMBtu	54.0	N/A	N/A
	NO_x[2]	0.0333 lb/MMBtu	0.0074 lb/MMBtu	76.8	N/A	N/A
	CO	0.0281 lb/MMBtu	0.0045 lb/MMBtu	101.8	N/A	N/A
	VOC	0.0036 lb/MMBtu	0.0026 lb/MMBtu	18.9	N/A	N/A
	SO_2	0.0015 lb/MMBtu	0.0015 lb/MMBtu	15.6	N/A	N/A
	Max HAP[3]	N/A	N/A	3.6	N/A	N/A
	Total HAPs[3]	N/A	N/A	6.9	N/A	N/A
	NH_3	NA	0.0027 lb/MMBtu	28.0	N/A	N/A
	CO_2[4]	842 lb/MW net	842 lb/MW net	1,233,952	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 ($PM_{2.5}$). *Note that vendor performance is given in lb/hr which varies with load.*

[2] NOx emissions from this proposed project need to be included for the purposes of NOx 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 net MW is based on a "new and clean" net heat rate of 7,080 Btu per kWh delivered to the grid, at base load conditions, and corrected to ISO weather conditions of 59°F, 14.7 psia, and 60% humidity.

[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.

D. Best Available Control Technology (BACT) Emissions

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

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

Table 9A

Emission Unit No. & Fuel Used	Air Contaminant	Uncontrolled Emissions (Pounds per Hour [lbs/hr], Pounds per 1 Million British Thermal Units [lb/MMBtu] or Parts per Million Dry Volume Corrected Basis [ppmvd@ %O2 or CO2])	Proposed BACT Emissions (lbs/hr, lb/MMBtu or ppmvd@ %O2 or CO2)	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. 1, 2 (per unit) Fuel Used Natural gas	PM[1]	16.1 lb/hr	16.1 lb/hr	54.0	N/A	N/A
	$PM_{2.5}$	16.1 lb/hr	16.1 lb/hr	54.0	N/A	N/A
	PM_{10}	16.1 lb/hr	16.1 lb/hr	54.0	N/A	N/A
	NO_x[2]	81.5 lb/hr	18.1 lb/hr	76.8	N/A	N/A
	CO	68.8 lb/hr	11.0 lb/hr	101.8	N/A	N/A
	VOC	8.8 lb/hr	6.4 lb/hr	18.9	N/A	N/A
	SO_2	3.7 lb/hr	3.7 lb/hr	15.6	N/A	N/A
	Max HAP[3]	N/A	N/A	3.6	N/A	N/A
	Total HAPs[3]	N/A	N/A	6.9	N/A	N/A
	NH_3	NA	6.6 lb/hr	28.0	N/A	N/A
	CO_2[4]	842 lb/MW net	842 lb/MW net	1,233,952	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] NOx emissions from this proposed project need to be included for the purposes of NOx 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 net MW is based on a "new and clean" net heat rate of 7,080 Btu per kWh delivered to the grid, at base load conditions, and corrected to ISO weather conditions of 59°F, 14.7 psia, and 60% humidity.

[5]Enter "N/A" if not requesting emissions restrictions and/or fuel usage limit.