Attachment 1

Emissions Update and Prevention of Significant Deterioration Best Available Control Technology Report

Salem Harbor Redevelopment Project
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1.0 INTRODUCTION

This document presents updated information for the Salem Harbor Redevelopment Project (the "Project'). Certain Project emissions have been reduced based on improved performance data obtained from General Electric (GE), in response to various public comments submitted on draft permit documents issued by MassDEP on September 9, 2013. The Prevention of Significant Deterioration (PSD) Best Available Control Technology (BACT) analysis has also been documented in greater detail.

This document includes:

- Updated combustion turbine and facility emissions (Sections 2.0)
- Updated PSD review applicability (Section 3.0)
- Updated PSD BACT analysis (Section 4.0)

The updated emissions presented in this document reflect recent updates to information General Electric (GE) has provided regarding emissions from the equipment selected for the Project, which is the General Electric Model 7FA Series 5 turbine (the "turbine"). That is, the updated information results in significant reductions to proposed emissions of CO and PM for the Project.

<u>CO Emissions</u>. The Applicant has obtained new performance data from GE which indicates not only that that CO will be controlled to within 2.0 ppmvdc at loads $\geq$ MECL (minimum emission compliance load), (as reflected in the public review documents), but also that CO emissions at loads $\geq$ MECL will also not exceed 8.0 lbs/hr, with and without duct firing. This emission cap of 8.0 lb/hr is achievable since the combustion turbines operate very efficiently at high load conditions. Actual CO emissions will be less than 2.0 ppmvdc at high operating loads, which allows for maximum lb/hr emission of CO to remain $\leq$ 8.0 lb/hr.

The Applicant is also now proposing to install a CO oxidation catalyst on the auxiliary boiler. This reduces the auxiliary boiler potential-to-emit for CO from 9.2 to 0.9 tons per year. There is, however, a small collateral increase in H_2SO_4 potential emissions from the auxiliary boiler due to this oxidation catalyst.

In addition, the Applicant has identified and corrected an error in the calculation of annual CO emissions. This error occurred in the assumptions used to calculate the startup/shutdown annual scenario originally presented in Appendix B (Calculation Sheet 2) of the December 21, 2012 Application. In these calculations, the Applicant had mistakenly assumed that startups occurring on a Monday morning (after being offline over the weekend) would be "cold starts" rather than "warm starts". However, as recently pointed out by GE, GE defines a cold start as when the turbine has been offline for *more than* 72 hours. In contrast, the modeled Monday morning startups at the Project will occur when the turbines have been down less than 60 hours after shutting down on Friday evening. Accordingly, these Monday morning startups will be "warm starts" rather than cold starts. Since warm starts have lower CO emissions than cold starts, the CO emissions from the turbines during the corrected start-up scenario will be less than originally calculated.

The annual CO emissions have been revised incorporating the updates described above, and the resulting proposed maximum annual emissions for the Project are now *reduced* to 88.0 tons per year. The Project maximum annual CO emissions are reduced from 106.3 tpy, a 17% reduction. Emissions totals for the turbines will be verified through the CO CEMS monitoring and reporting as specified in the draft permits.

PM Emissions. The other recent emission update included in this document is the reduction to the combustion turbine particulate emissions. This update is due to lower particulate emission guarantees provided by GE, as described in the Applicant's comment letter to MassDEP dated November 1, 2013. GE has been collecting new PM test data for combustion turbine combined cycle units using strict quality control methods for EPA test procedures, and based on this latest data GE is confident the new lower limits can be achieved. The project maximum annual emissions for PM are reduced by 25%.

Other Updates. As noted above, the addition of the oxidation catalyst to the auxiliary boiler results in a small collateral increase in H_2SO_4 emissions, due to the additional oxidation of SO_2 to SO_3 in the auxiliary boiler exhaust. In addition, the lb/hr emission rates for the combustion turbines for NO_x, SO_2, NH_3 and H_2SO_4 for unfired conditions (i.e., no duct firing) have been reduced, in response to one of the CLF comments on the draft permit documents. The lb/hr rates for all these pollutants in the draft permit documents dated September 9, 2013 were based on the worst case emissions for duct firing, using a firing rate of 2449 MMBtu/hr/combined cycle unit. We have included the (lower) maximum lb/hr rates for unfired conditions (maximum firing rate of 2300 MMBtu/hr/turbine) in this document.

In all other respects, the turbine emissions are the same as presented in the draft permit documents issued by MassDEP on September 9, 2013.

2.0 COMBUSTION TURBINE AND FACILITY EMISSIONS

2.1 Short-Term Turbine Emissions

Short-term potential emission rates for each combined cycle unit, including the combustion turbine and associated duct burner, are presented in Table 2-1. The updated rates shown in Table 2-1 reflect both (1) GE's recent commitment that CO emissions at loads $\geq$ MECL will not exceed 8.0 lbs/hr, with and without duct firing, (2) GE's revised guaranty of reduced PM, and (3) the other updates as noted at the end of section 1.0 above. The lb/hr rates shown for duct firing are based on the following assumptions, which are the same as in the draft permit documents: peak load operation at 90 °F, with duct burner firing and evaporative cooling, and represent the worst case hourly emissions. Worst-case hourly emissions without duct firing are also shown, and are based on 100% (base) load operation at 0 ^{o}F. 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; pounds per hour (lb/hr); and lb/MWhr. The lb/MWhr values for unfired conditions (i.e., no duct firing) are based on an initial compliance test at 100% (base) load. The lb/MWhr values for duct firing conditions are based on an initial compliance test at peak load (approximately 102% load) with 100% duct firing.

Table 2-1. Short-Term Emission Rates for Combustion Turbine Combined Cycle Units

Pollutant	ppmvd at 15% O_2	lb/MMBtu	lb/hr (per Unit)	lb/MWhr
NO_x, unfired	2.0	0.0074	17.0	0.051
NO_x, duct-fired	2.0	0.0074	18.1	0.055
CO, unfired	2.0	0.0045	Not to exceed 8.0	0.025
CO, duct fired	2.0	0.0045		0.027
VOC, unfired	1.0	0.0013	3.0	0.009
VOC, duct-fired	1.7	0.0022	5.4	0.016
SO_2, unfired	0.3	0.0015	3.5	0.010
SO_2, duct-fired	0.3	0.0015	3.7	0.011
$PM/PM_{10}/PM_{2.5}$, unfired	N/A	0.0071	8.8	0.029
$PM/PM_{10}/PM_{2.5}$, duct-fired	N/A	0.0062	13.0	0.041
NH_3, unfired	2.0	0.0027	6.2	0.019
NH_3, duct-fired	2.0	0.0027	6.6	0.020
H_2SO_4, unfired	0.1	0.0010	2.2	0.007
H_2SO_4 duct-fired	0.1	0.0010	2.3	0.008

Emissions changes from the draft permit documents issued by MassDEP are highlighted.

Table 2-2 provides updated emission rates for the auxiliary boiler. The updated values reflect the addition of the oxidation catalyst which reduces CO but causes a collateral increase in H_2SO_4 emissions.

Table 2-2 Emission Rates for Auxiliary Boiler

Pollutant	Auxiliary Boiler lb/MMBtu	Auxiliary Boiler lb/hr	Auxiliary Boiler tpy
NO_x	0.011	0.88	2.9
CO	0.0035	0.28	0.9
VOC	0.005	0.40	1.3
SO_2	0.0015	0.12	0.4
PM	0.005	0.40	1.3
PM_{10}	0.005	0.40	1.3
$PM_{2.5}$	0.005	0.40	1.3
H_2SO_4	0.0009	0.072	0.24

Emissions changed from the draft permit documents issued by MassDEP are highlighted.

The increase in H_2SO_4 emissions from the auxiliary boiler does result in an increase in the H_2SO_4 impacts as presented in Table 6-13 of Attachment 1 of the Second Supplement to the Air Plans Application, dated June 10, 2013. This same information is also presented in Table 3 of MassDEP's proposed Air Quality Plan Approval (page 15 of 59), dated September 9, 2013. The maximum 24-hr (TEL) impact for H_2SO_4 increases from 0.053184 to 0.084823 micrograms per cubic meter (ug/m3). This represents an increase from 1.955% to 3.119% of the TEL. The maximum annual (AAL) impact for H_2SO_4 increases from 0.001841 to 0.005963 (ug/m3). This represents an increase from 0.068% to 0.219% of the AAL. The resulting concentrations still remain far below the applicable criteria.

It should also be recognized that we have conservatively not documented the various reductions in ambient air quality impacts resulting from the reduced emissions for PM_{10}, $PM_{2.5}$ and CO that are now incorporated into the Project.

2.2 Long-Term Project Emissions

The proposed annual potential emissions from the Project are summarized in Table 2-3. These limits have been updated to account for the reductions in CO and PM emissions rates, described above. The limits are also based on the following assumptions, which are the same as stated in the draft permit documents:

- 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 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 2-3. 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	69.9	69.9	2.9	1.7	0.4	0	144.8
CO	42.9	42.9	0.9	1.0	0.3	0	88.0
VOC	13.1	13.1	1.3	0.35	0.12	0	28.0
SO_2	14.2	14.2	0.4	0.0017	0.0006	0	28.8
PM	40.1	40.1	1.3	0.06	0.02	0.43	82.0
PM_{10}	40.1	40.1	1.3	0.06	0.02	0.43	82.0
$PM_{2.5}$	40.1	40.1	1.3	0.06	0.02	0.17	81.8
NH_3	25.5	25.5	0	0	0	0	51.0
H_2SO_4 mist	9.4	9.4	0.24	0.00013	0.00005	0	19.0
Lead	0	0	0.00013	0.000001	0.0000003	0	0.00013
Formaldehyde	3.3	3.3	0.019	0.00009	0.0005	0	6.6
Total HAP	6.3	6.3	0.5	0.0018	0.0016	0	13.1
CO_2	1,122,920	1,122,920	31,247	180	66	0	2,277,333
CO_2e	1,124,003	1,124,003	31,277	181	66	0	2,279,530

Emissions changes from the draft permit documents issued by MassDEP are highlighted.

The combustion turbines have higher hourly mass emissions of CO during startup and shutdown than during full-load operation. Therefore, the annual potential emissions of CO in Table 2-3 are based on a simulated operating year that includes a conservative number of startup and shutdown cycles. Table 2-4 below presents the revised operating scenario used to calculate annual potential emissions for CO. Table 2-4 includes the corrections to the assumptions discussed in Section 1.0 above. The number of operating hours and startup/shutdown cycles shown are per combustion turbine.

Appendix A presents an update to the supporting calculation sheets originally provided in Appendix B of the December 21, 2012 Application.

Table 2-4 Combustion Turbine Operating Scenario for Annual CO 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	5	95	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	2	40	0
N/A	Planned outage	N/A	6	0	0
N/A	Unplanned outage	N/A	0	0	4
Annual Totals		3,272	13	189	4

3.0 PREVENTION OF SIGNIFICANT DETERIORATION (PSD) REVIEW APPLICABILITY

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 Project 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 3-1 presents a PSD major source threshold analysis for the Project for those pollutants with applicable PSD emission criteria. As shown in Table 3-1, the Project is now subject to PSD review (i.e., exceeds significant emissions rates) for particulates ($PM/PM_{10}/PM_{2.5}$), NO_x, sulfuric acid mist (H_2SO_4), and GHGs.

The only PSD review *applicability* change from the draft permit documents is that, based on the new and corrected information described above, CO is no longer subject to PSD review. That is, the proposed project annual emissions of CO (88.0 tpy) are now below the significant emission rate for CO (100 tpy). In addition, the proposed project annual emissions for $PM/PM_{2.5}/PM_{10}$ are now reduced based on the recent guarantees from GE, as described in section 1.0, above.

Table 3-1. 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	88.0	100	100	No
NO_x	144.8	100	40	Yes
SO_2	28.8	100	40	No
PM	82.0	100	25	Yes
PM_{10}	82.0	100	15	Yes
$PM_{2.5}$	81.8	100	10	Yes
VOC (ozone precursor)	28.0	100	40	No
Lead	0.00013	100	0.6	No
Fluorides	Negligible.	100	3	No
Sulfuric Acid Mist (H_2SO_4)	19.0	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	none expected	100	10	No
GHGs (as CO_{2e})	2,279,530	100,000	75,000	Yes

Changes from the draft permit documents issued by MassDEP are highlighted.

4.0 CONTROL TECHNOLOGY ANALYSIS

This section presents an updated PSD BACT analysis for the Project. This updated analysis addresses comments made on the draft permit and reflects the additional information and corrections described in sections 1, 2, and 3 above. As discussed above, the Project exceeds PSD significant emission thresholds for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus is subject to PSD BACT for these pollutants. The Project does not exceed PSD significant emissions thresholds for CO.

The Project remains subject to MassDEP BACT for all pollutants. The MassDEP BACT analysis as reflected in the prior application materials and the MassDEP draft permit documents remains valid and is not addressed here. This section specifically addresses PSD BACT requirements.

PSD BACT is defined in 40 CFR 52.21 means "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

Typically, PSD BACT follows a five step "top-down" approach: (1) identify all control technologies; (2) eliminate technically infeasible options; (3) rank remaining control technologies by control effectiveness; (4) evaluate most effective controls and documents results; and (5) select BACT.

However, a key exception to the strict, five-step "top-down" approach is described in page B-8 of the EPA's October 1990 draft New Source Review Workshop Manual (the "NSR Manual," as cited in the EPA comment letter):

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

4.1 Combined Cycle Combustion Turbines

4.1.1 Fuel Selection

Fuel selection is an important consideration with respect to all pollutants subject to PSD review for the facility (NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG). Therefore, fuel selection for the combustion turbine combined cycle units is initially discussed here, prior to the PSD BACT evaluation for the individual PSD pollutants, instead of repeating this under the evaluation for each pollutant.

The Applicant proposes to use natural gas only for the combined cycle turbines.

Step 1: Identify all control technologies (fuel types).

Identified control technologies (fuel types) for combustion turbine combined cycle units are:

1. Use of natural gas only.
2. Primarily natural gas with liquid fuel as a backup fuel. Liquid fuel could be ultra-low sulfur distillate (ULSD), biodiesel or a mixture of these.

Step 2: Eliminate technically infeasible options

Both above fuel options are technically feasible. An acceptable mixture for ULSD/biodiesel is subject to confirmation by turbine suppliers.

Step 3: Rank remaining control technologies by control effectiveness.

Natural gas is the lowest emitting commercially available fuel for combustion turbine combined cycle units. ULSD and biodiesel have higher emissions than natural gas for NO_x, $PM/PM_{10}/PM_{2.5}$ and GHG. H_2SO_4 emissions depend on the maximum sulfur content of the fuel. ULSD and biodiesel are normally specified at 15 ppm sulfur by weight, and pipeline natural gas is defined by USEPA in 40 CFR 72.2 to have a maximum sulfur content of 0.5 grains/100 scf. These values are effectively identical in the amount of sulfur per MMBtu of fuel. However, natural gas as delivered is likely to have a lower actual sulfur content per MMBtu of fuel compared to ULSD or biodiesel.

Since natural gas is a lower emitting fuel than ULSD or biodiesel, it ranks higher in terms of control effectiveness and is considered the top BACT alternative.

Step 4: Evaluation of Collateral Impacts

Energy Impacts

Within the past decade, natural gas has become increasing abundant in the New England, due to increased availability of domestic sources of gas. However, concerns have been raised regarding the lack of regional fuel diversity and potential overreliance on natural gas for energy supplies. In particular, pipeline infrastructure to deliver gas into New England can become constrained during cold weather as space heating and electric production compete for available gas supplies. These issues have resulted in considerations for more energy diversity and backup liquid fuel supplies for electric generation facilities.

Since the Applicant has committed to use natural gas exclusively in the combustion turbine combined cycle units, potential energy concerns with exclusive natural gas use are an important consideration. The Project will obtain natural gas from its direct connection to Algonquin’s HubLine interstate natural gas pipeline near HubLine’s interconnection with the Maritimes & Northeast Pipeline. This unique interconnection point permits the Project to access supplies of natural gas from both Canadian sources as well as from domestic sources the south and west. The Maritimes & Northeast Pipeline has not had the same physical delivery constraints as the heavily relied-upon pipelines delivering natural gas into New England exclusively from the south and west. Therefore, energy concerns due to exclusive natural gas use are not problematic for this Project.

Economic Impacts

Natural gas is currently a much more favorable economically compared to liquid fuels, and this situation is expected retain this current pattern into the foreseeable future. With Footprint's access to Canadian Maritime gas, potential short-term price spikes due to physical supply constraints are not expected to be problematic. Therefore, there are no economic considerations that would dictate that backup provisions for liquid fuel are necessary.

Environmental Impacts

In addition to being a higher emitting fuel for air emissions, liquid fuel has other significant collateral impacts compared to natural gas. The most significant collateral impact is associated with the truck delivery of liquid fuel to the site. Although liquid fuel could be delivered by barge as well, the local community has expressed its strong opposition to the continued storage and combustion of liquid fuel on the site for power generation. These impacts are of significant concern to the local Salem community, and in fact have led to a commitment by the Applicant not to use liquid fuel for the combustion turbine combined cycle units at the site.

The other collateral environmental impact of note is the fact that NO_x control for liquid fuel requires the use of water or steam injection to the turbine combustor. The use of water/steam injection would result in a significant consumptive water use and an associated discharge of water that is not needed for dry low-NO_x combustors, which are available for natural gas.

Step 5: Select BACT

Use of natural gas as the exclusive fuel for the combustion turbine combined cycle units is clearly justified as PSD BACT. Natural gas is lower emitting, has significantly lower collateral environmental impacts, and collateral energy and economy impacts have been determined to be acceptable.

4.1.2 PSD Best Available Control Technology Assessment for NO_x

Step 1: Identify Candidate Technologies

NO_x control technologies identified for new large > 100 MW combined cycle turbines are as follows:

- Dry-low NO_x (DLN) Combustion: Turbine vendors offer what is known as lean pre-mix combustors for natural gas firing which limit NO_x formation by reducing peak flame temperatures.
- Water or Steam Injection: Water or steam injection has been historically used for both gas and oil fire turbines, but for new turbines is generally only used for liquid fuel firing.
- Catalytic Combustors: A form of catalytic combustion to limit firing temperature has been under development using the trade name XONON.
- SCONOx: This is an oxidation/absorption technology using hydrogen or methane as a reactant. This technology is currently marketed as EMx.

- SCR: This is a catalytic reduction technology using ammonia as a reactant that has been in widespread use on new combined cycle turbines for over 20 years.

Step 2: Eliminate Infeasible Technologies

Catalytic combustors are not currently technically feasible for large turbines. The only known application is on a 1.4 MW test turbine. The largest turbine to which SCONOx has been successfully demonstrated is a 43 MW turbine in California. There are significant SCONOx scale up questions for a new turbine larger than 100 MW, but for the sake of argument SCONOx will be assumed to be technically feasible here. The other technologies are all technically feasible.

Step 3: Rank Control Technologies by Control Effectiveness

The ranking of these technologies is as follows:

1. SCR: Widely demonstrated to have achieved 2.0 ppmvd NO_x at 15% O_2 for gas firing. This is documented in the LAER analysis presented in the December 21, 2012 Application and First Application Supplement (April 12, 2013).
2. SCONOx: Demonstrated to have achieved 2.5 ppmvd NO_x at 15% O_2 at the 43 MW California unit.
3. DLN: Generally recognized to achieve 9 ppmvd NO_x at 15% O_2. Commonly used in conjunction with SCR to achieve 2.0 ppmvd NO_x at 15% O_2.
4. Steam/Water Injection: Less effective than DLN.

Step 4: Evaluate Controls

Since Footprint is proposing the "top" level for NO_x BACT (SCR), the BACT analysis can proceed to the consideration of whether any collateral energy or environment impacts would indicate other than the top demonstrated technology be selected.

The one collateral impact that has been identified for SCR is due to the use of ammonia as a reagent, and the resulting emissions of ammonia "slip" that can occur. SCONOx does not require the use of ammonia. While SCONOx will eliminate the use of ammonia, the lower NO_x emissions demonstrated in practice with SCR (2.0 ppmvdc vs. 2.5 ppmvdc for SCONOx) and the very high additional cost documented with SCONOx does not justify a finding that SCONOx is BACT. This same conclusion is found in the EPA Analysis for the Pioneer Valley Energy Center (PVEC), in the Fact Sheet published in December 2011. SCONOx is not justified as BACT. In addition, as documented in the Application and supplements, the predicted ambient air quality impacts for ammonia are well below the MassDEP air toxics guidelines. Aqueous ammonia will be stored in a 34,000 gallon above ground tank located within a concrete dike designed to contain 110% of the total tank volume. Passive evaporative controls will be used inside the dike to control evaporation in the event of a release, and the tank and dike will be in a fully enclosed and sealed structure except for roof vents. Evaluation of a hypothetical worst case release indicates that ammonia concentrations at and outside the Project perimeter will be less than the ERPG-1 level. ERPG-1 is defined as the maximum airborne concentration below which nearly all individuals could be exposed for up to one hour without experiencing other than mild transient adverse health effects or perceiving a clearly defined, objectionable odor.

Step 5: Select BACT

The Footprint Project will meet the same 2.0 ppmvdc NO_x limit as determined to be BACT for PVEC. The Project will also meet a stringent emission limit for ammonia slip (2.0 ppmvdc on a 1-hour basis), which is the most stringent ammonia limit achieved in practice for facilities of this type. This stringent ammonia limit assures that collateral impacts are adequately minimized for the use of SCR for the Footprint Project, and that this represents BACT for NO_x.

4.1.3 PSD Best Available Control Technology Assessment for PM/PM_{10}/$PM_{2.5}$

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 for the combustion turbines are assumed to be less than 2.5 microns in size ($PM_{2.5}$).

Pursuant to identifying candidate control technologies under the “top-down” procedure, Footprint has compiled all the PSD BACT determinations in the last five years for new large (> 100 MW) combustion turbine combined cycle project. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. The Brockton Energy Center Project in Brockton MA is also included, since it is a similar recent project in Massachusetts, even though it did not receive a PSD permit. This review confirms that the only BACT technology identified for large natural gas fired combined cycle turbines is use of clean fuel (i.e., natural gas) and good combustion practices.

For PM/PM_{10}/$PM_{2.5}$, this evaluation does not identify and discuss each of the five individual steps of the “top-down” BACT process, since there are no post-combustion control technologies available for PM/PM_{10}/$PM_{2.5}$. Post-combustion particulate control technologies such as fabric filters (baghouses), electrostatic precipitators, and/or wet scrubbers, which are commonly used on solid fuel boilers, are not available for combustion turbines since the large amount of excess air inherent to combustion turbine technology would create adverse backpressure for turbine operation.

The “top-down” procedure does require selection of BACT emission limits, which is addressed in the following paragraphs.

Table 4-1 presents the results of RBLC compilation for PM/PM_{10}/$PM_{2.5}$. A review of Table 4-1 indicates that PM/PM_{10}/$PM_{2.5}$ emission limits are expressed strictly in lbs/hr or lb/MMBtu, or in both lb/hr and lb/MMBtu. This review also indicates that different emission limits can be associated with different turbine suppliers. This is illustrated by some projects which have one set of limit for one supplier and another set of limits for another supplier.

It is Footprint’s conclusion based on review of available information that differences in PM/PM_{10}/$PM_{2.5}$ emission limits among various projects are due to different emission guarantee philosophies of the various suppliers, and are not actual differences in the quantity of PM/PM_{10}/$PM_{2.5}$ emissions inherently produced by the supplier of the turbine. The different emission guarantee philosophies are influenced by the overall uncertainties of the PM/PM_{10}/$PM_{2.5}$ test procedures, especially given reported difficulties in achieving test repeatability, and concerns with artifact emissions introduced by the general inclusion of condensable particulate emissions (as measured by impinger based techniques) in permit limits in the last decade.

Table 4-1. Summary of Recent Particulate PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] PM/PM_{10}/$PM_{2.5}$
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	12.4 lb/hr/unit and 0.0108 lb/MMBtu without DF 19.8 lb/hr and 0.0078 lb/MMBtu with DF
Renaissance Power	Carson City, MI	11/1/2013	4 Siemens 501 FD2 units 2147 MMBtu/hr/unit each with 660 MMBtu/hr DF	9.0 lb/hr/unit and 0.0042 lb/MMBtu (with and without DF)
Langley Gulch Power	Payette, ID	08/14/2013	1 - Siemens SGT6-5000F 2134 MMBtu/hr/unit with 241.28 MMBtu/hr DF	12.55 lb/hr (w/ and w/o DF)
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: 11.3 lb/hr/unit and 0.00384 lb/MMBtu without DF Mitsubishi: 10.1 lb/hr and 0.00373 lb/MMBtu with DF Siemens: 14.0 lb/hr/unit and 0.0055 lb/MMBtu without DF Siemens: 13.3 lb/hr and 0.0047 lb/MMBtu with DF
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	2 GE 7FA.05 2230 MMBtu/hr/unit plus 650 MMBtu/hr DF or 2 Siemens SGT6-5000F5 2260 MMBtu/hr/unit plus 450 MMBtu/hr DF	GE: 0.00334 lb/MMBtu at full load (w/ and w/o DF) 9.6 lb/hr/unit without DF 16.2 lb/hr with DF Siemens: 0.00374 lb/MMBtu at full load (w/ and w/o DF) 10.1 lb/hr/unit without DF 14.5 lb/hr with DF
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	GE7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H. 2 combined cycle units	11.0 lb/hr/unit without DF 18.5 lb/hr/unit with DF Emissions based on Siemens SGT6-8000H
Sunbury Generation	Sunbury, PA	04/01/2013	“F Class” with DF 2538 MMBtu/hr/unit	0.0088 lb/MMBtu
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	9.7 lb/hr/unit and 0.0033 lb/MMBtu without DF 16.3 lb/hr and 0.0047 lb/MMBtu with DF
Moxie Patriot LLC	Clinton Twp, PA	01/31/2013	Equipment type not specified 2 - 472 or 458 MW combined cycle blocks with DF	0.0057 lb/MMBtu
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA 309 MW	32.1 lb/hr
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	4 - “F Class” (GE or Siemens) 1345 MW total	15 lb/hr/unit and 0.0092 lb/MMBtu without DF 18 lb/hr and 0.0078 lb/MMBtu with DF
Hess Newark Energy	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	11 lb/hr/unit without DF 13.2 lb/hr with DF

Table 4-1. **Summary of Recent Particulate PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants**

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] PM/PM_{10}/$PM_{2.5}$
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	27.0 lb/hr
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Siemens "H Class" 2 – 468 or less MW combined cycle blocks GT ≤ 2890 MMBtu/hr/unit DF ≤ 3870 MMBtu/hr/unit	0.0057 lb/MMBtu for 454 MW block 0.0040 lb/MMBtu for 468 MW block
Cricket Valley	Dover, NY	09/27/2012	3 - GE 7FA.05 2061 MMBtu/hr/unit plus 379 MMBtu/hr DF	0.005 lb/MMBtu without DF 0.006 lb/MMBtu with DF
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	27.0 lb/hr
ES Joslin Power	Calhoun, TX	09/12/2012	3 - GE 7FA 195 MW per unit No DF	18.0 lb/hr
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	9.8 lb/hr 0.004 lb/MMBtu
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	2 GE 7FA 154 MW (1736 MMBtu/hr) per unit plus 500 MMBtu/hr DF	8.46 lb/hr/unit and 0.0048 lb/MMBtu without DF 11.3 lb/hr and 0.0049 lb/MMBtu with DF
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	18.0 lb/hr
Entergy Ninemile Point Unit 6	Westwego, LA	08/16/2011	Vendor not specified Single unit 550MW	26.23 lb/hr/unit without DF 33.16 lb/hr with DF
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	1 Siemens SGT6-PAC-5000F 2227 MMBtu/hr plus 641 MMBtu/hr DF	17.4 lb/hr 0.007 lb/MMBtu
Avenal Power Center	Avenal, CA	05/27/2011	2 - GE 7FA 1856.3 MMBtu/hr/unit plus 562.26 MMBtu/hr DF	8.91 lb/hr/unit without DF 11.78 lb/hr with DF
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	1 - Mitsubishi M501GAC 2866 MMBtu/hr	0.0083 lb/MMBtu
Dominion Warren County	Front Royal, VA	12/21/2010	3 -Mitsubishi M501 GAC 2996 MMBtu/hr/unit plus 500 MMBtu/hr DF	8.0 lb/hr/unit and 0.0027 lb/MMBtu without DF 14.0 lb/hr and 0.0040 lb/MMBtu with DF

Table 4-1. Summary of Recent Particulate PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] PM/PM_{10}/$PM_{2.5}$
Pondera/King Power Station	Houston, TX	08/05/2010	4 GE 7FA.05 2430 MMBtu/hr/unit GT plus DF or 4 Siemens SGT6-5000F5 2693 MMBtu/hr/unit GT plus DF	GE: 19.80 lb/hr/unit (w/ and w/o DF) Siemens: 11.1 lb/hr/unit (w/ and w/o DF)
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	No emission limits specified. PSD BACT for PM_{10}/$PM_{2.5}$ use of pipeline quality natural gas
Victorville 2 Hybrid	Victorville, CA	03/11/2010	2 GE 7FA 154 MW per unit plus 424.3 MMBtu/hr DF	12.0 lb/hr/unit without DF 18.0 lb/hr with DF
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	2 GE 7FA 170 MW/unit plus 570 MMBtu/hr DF or 2 Mitsubishi M501G 254 MW/unit plus 230 MMBtu/hr DF	GE: 12.0 lb/hr/unit (w/ and w/o DF) Mitsubishi: 20.0 lb/hr/unit (w/ and w/o DF)
Panda Sherman Power	Grayson, TX	02/03/2010	2 GE 7FA or 2 Siemens SGT6-5000F with 468 MMBtu/hr/unit DF	GE: 12.0 lb/hr/unit (without DF) 27.0 lb/hr with DF Siemens: 11.0 lb/hr/unit without DF 15.4 lb/hr with DF
Russell City Energy Center	Hayward, CA	02/03/2010	2 - Siemens 501F 2238.6 MMBtu/hr/unit plus 200 MMBtu/hr DF	7.5 lb/hr/unit 0.0036 lb/MMBtu
Lamar Power Partners II LLC	Paris, TX	06/22/2009	4 - GE 7FA with 200 MMBtu/hr DF	18.0 lb/hr/unit without DF 20.3 lb/hr with DF
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 – GE 7FA, GE7FB, or Siemens SGT6-5000F With DF	20.8 lb/hr/unit (each option)
Entergy Lewis Creek Plant	The Woodlands, TX	05/19/2009	2 - GE 7FA with 362 MMBtu/hr DF	27.14 lb/hr/unit

[1] DF refers to duct firing

[2] Includes front (filterable) and back-half (condensable) PM. Limits obtained from agency permitting documents when not available in RBLC. Short-term emission limits only are provided.

GE has historically guaranteed particulate emissions on constant lb/hr basis, regardless of turbine load. Thus, as shown in Table 4-1, many of the GE turbines have PSD BACT limits expressed strictly in lb/hr.

Footprint has calculated lb/MMBtu values inclusive of minimum emission compliance load (MECL). (Note that duct-firing will not occur at MECL, so the MECL-based limit is only for unfired conditions). Footprint has determined that the flexibility to operate at MECL is important to the Project's mission of providing a flexible and quick response to the future system power needs. Footprint's draft PSD permit and Plan Approval also require $PM/PM_{10}/PM_{2.5}$ emission testing at MECL. MECL turbine operation therefore results in Footprint's highest lb/MMBtu rate of 0.0071 lb/MMBtu. It is important to note that a number of the lb/MMBtu emission rates in Table 4-1 correspond to (just) the full load heat input rate. For comparative purposes, the Footprint full load lb/MMBtu/hr $PM/PM_{10}/PM_{2.5}$ emission rate (without duct firing) ranges from 0.0038 to 0.0047 lb/MMBtu.

Table 4-1 lists 34 projects with PSD BACT limits for $PM/PM_{10}/PM_{2.5}$ approved in the last 5 years. Over half of these projects (18) clearly have $PM/PM_{10}/PM_{2.5}$ limits less stringent than the Footprint limits discussed above. Of the remaining 16 projects, most of these are for turbine suppliers other than GE, and generally have lower $PM/PM_{10}/PM_{2.5}$ limits expressed on a lb/MMBtu basis. The lb/MMBtu comparison allows $PM/PM_{10}/PM_{2.5}$ rates for projects of different sizes to be more readily compared. The most stringent lb/MMBtu limit identified is for the Dominion Warren County (VA) project, which is 0.0027 lb/MMBtu without duct firing. The Dominion Warren County project is based on 3 Mitsubishi 501GAC turbines. Mitsubishi in particular has recently taken a more aggressive approach to $PM/PM_{10}/PM_{2.5}$ guarantees, as reflected by the Warren County Project as well as the Brunswick County (VA) project (0.0033 lb/MMBtu without duct firing and 0.0047 lb/MMBtu with duct firing), the Oregon (Ohio) project (0.00384 lb/MMBtu without duct firing and 0.00373 lb/MMBtu with duct firing) and PVEC (0.004 lb/MMBtu without duct firing as noted in the CLF comment letter to MassDEP on the Footprint project).

With respect to the $PM/PM_{10}/PM_{2.5}$ limits achievable for the Mitsubishi 501GAC turbine, it is significant to note that an email from George Pyros of Mitsubishi Power Systems dated October 7, 2013, which was submitted to MassDEP in comments concerning Footprint Power, indicates that Mitsubishi has "not yet conducted stack PM emissions testing for our M501GAC gas turbine in combined cycle. However, we have M501GAC units that will be commissioned next year in combined cycle that will provide such data." (The Mitsubishi 501GAC project that is closest to commissioning is the Dominion Warren County project.) The email from Mitsubishi actually supports Footprint's position, as provided in supplemental material submitted to MassDEP on August 20, 2013, insofar as the fact that ultra-low particulate rates for the 501GAC turbine are not demonstrated in practice. In the August 20, 2013 submission, Footprint questioned whether the 0.004 lb/MMBtu emission rate for the PVEC was achievable in practice. This is based on the fact that four Mitsubishi 501G units at Mystic Station (Everett MA), had tested PM emissions (in 2003) ranging from 0.005 – 0.010 lb/MMBtu. While the 501GAC turbine has a newer generation combustion system, the majority of the tested particulate matter at Mystic was condensable particulates. It is not at all clear how a newer generation combustion system would achieve better control of condensable particles. While careful adherence to particulate testing procedures can minimize testing variably and artifact condensable emissions, Footprint remains convinced that the Mitsubishi's recent 501GAC limits, particularly those for the Warren County project, present undue project risk.

In addition, for Mitsubishi and Siemens projects with $PM/PM_{10}/PM_{2.5}$ lb/MMBtu limits, these limits appear to be approved as constant across the operating load range. This represents a different guarantee philosophy than used by GE. Again, Footprint believes this is a guarantee philosophy difference and does not reflect actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions due to the type of turbine. As noted in Footprint's comment letter to MassDEP dated November 1, 2013, at full load unfired conditions, Footprint's lb/MMBtu rates for $PM/PM_{10}/PM_{2.5}$ range from 0.0038 to 0.0047 lb/MMBtu. These full load rates compare favorably to many of the lb/MMBtu rates for Siemens and Mitsubishi in Table 4-1.

Several Siemens "F Class" $PM/PM_{10}/PM_{2.5}$ limits in Table 4-1 (Renaissance, Langley Gulch, Pondera King) have lb/hr limits higher than the Footprint unfired value of 8.8 lb/hr, but do not incorporate higher duct firing limits (as is typically found to be necessary by available duct burner guarantees). Again, Footprint believes this is a guarantee philosophy difference and does not reflect actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions due to the type of turbine and whether duct firing is present or not.

The Russell City Energy Center Project is based on 2 Siemens 501F turbines, and was approved with $PM/PM_{10}/PM_{2.5}$ limits of 7.5 lb/hr and 0.0038 lb/MMBtu. Again, Footprint believes this is a guarantee philosophy difference and does not reflect actual differences in the quantity of $PM/PM_{10}/PM_{2.5}$ emissions. However, one item of particular note in the Russell City Energy Center PSD Permit is that the permit allows the facility to propose alternate measuring techniques to measure condensable PM, such as the use of a dilution tunnel. A dilution tunnel is expected to result in lower (and more realistic) tested emissions compared to typical stationary source impinger techniques for measuring condensable PM. Therefore, this permit provision may explain in part the rationale for the Russell City Energy Center strategy for accepting lower permit limits. Dilution tunnel based measurements for condensable PM are expected to more accurately simulate the process by which condensable PM forms compared to impinger techniques, which still present concerns with artifact emissions.

There is one other GE 7FA unit noted in Table 4-1 that has $PM/PM_{10}/PM_{2.5}$ limits of comparative note. This is the Green Energy (VA) project. This project is approved for either GE 7FA or Siemens turbines. For GE 7FA, the lb/hr limits are less stringent than Footprint but the lb/MMBtu limits are more stringent. The Green Energy lb/MMBtu limits appear to be incorrectly calculated (too low), even based on the full load firing rates.

In summary, the available evidence clearly indicates that PSD BACT for $PM/PM_{10}/PM_{2.5}$ emissions is to use of state of the art combustion turbines, with good combustion practices and the use of natural gas. The actual guarantees for $PM/PM_{10}/PM_{2.5}$ emissions vary by manufacturer, and permit limits within the range of recently approved projects for a given turbine supplier are justified as PSD BACT limits.

4.1.4 PSD Best Available Control Technology Assessment for Sulfuric Acid Mist (H_2SO_4)

Emissions of H_2SO_4 from natural gas-fired combined cycle units result from oxidation of trace quantities of sulfur in natural gas. Normally, fuel sulfur oxidizes to SO_2. A generally small portion of fuel sulfur may initially oxidize directly to SO_3 rather than SO_2. Also, a portion of the fuel sulfur which initially oxidizes to SO_2 may subsequently oxidize to SO_3 prior to being emitted. For purposes of emission calculations, all SO_3 is assumed to combine with water vapor in the flue gas to form H_2SO_4.

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of natural gas as the BACT fuel, this is the lowest sulfur content fuel available.

Key considerations in the development of a specific H_2SO_4 emission rate for a natural gas-fired combined cycle unit are the sulfur content of natural gas, and the appropriate allowance for oxidation of fuel sulfur and SO_2 to SO_3. For the sulfur content of natural gas, the Project has used the EPA definition of "pipeline natural gas" in 40 CFR 72.2. This definition is that pipeline natural gas has a maximum sulfur content of 0.5 grains of sulfur per 100 standard cubic feet (scf). Based on data from GE, up to 5% of the fuel sulfur is expected to convert directly to SO_3 in the turbine combustor/duct burners. Then, up to 35% of the (remaining) SO_2 is expected to convert to SO_3 in passing through the oxidation catalyst, and up to an additional 5% of the (remaining) SO_2 is expected to convert to SO_3 in passing through the SCR system. As documented in the Project supplemental data submitted to MassDEP on August 20, 2013, the resulting H_2SO_4 emission rate is 0.0010 lb/MMBtu. This corresponds to a maximum emission rate of 2.3 lb/hr of H_2SO_4 per unit.

Pursuant to identifying candidate control technologies under the “top-down” procedure, the Applicant has compiled all the PSD BACT determinations for H_2SO_4 in the last five years for new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. This review confirms that the only H_2SO_4 BACT technology identified for large natural gas fired combined cycle turbines is use of clean fuel (i.e., natural gas). There are no cases where any post combustion controls have been used to control H_2SO_4 emissions from large natural gas fired combined cycle turbines. Therefore, the PSD BACT analysis for H_2SO_4 does not require any evaluation of alternative control technologies.

The “top-down” procedure does require selection of BACT emission limits. Table 4-2 presents the results of RBLC compilation for H_2SO_4. As for $PM/PM_{10}/PM_{2.5}$, BACT emissions for H_2SO_4 can be expressed either as lb/MMBtu or lb/hr, or both. Table 4-2 lists 22 projects with PSD BACT limits for H_2SO_4 approved in the last 5 years. More than half of these projects (13) have H_2SO_4 limits equal or less stringent than the Footprint limits discussed above. Of the remaining 9 projects, the lower H_2SO_4 rates appear to be due to either unrealistically low assumptions on SO_2 to SO_3 oxidation, low assumed natural gas sulfur contents, or both. One of the projects listed in Table 4-2 (Panda Sherman) was approved without a CO oxidation catalyst, which explains the low H_2SO_4 rate for this project. As noted above, a CO oxidation catalyst oxidizes some of the SO_2 to SO_3/H_2SO_4. However, the other projects in Table 4-2 with lower H_2SO_4 rates appear to have assumed a very stringent natural gas sulfur content and/or did not take into account the unavoidable incremental oxidation of SO_2 to SO_3 from a CO catalyst. Footprint does not believe it is prudent to ignore the SO_2 to SO_3 oxidation from a CO catalyst, or assume a natural gas sulfur content lower than EPA’s definition for “pipeline natural gas” (0.5 grains of S/100 scf).

In summary, the available evidence clearly indicates that PSD BACT for H_2SO_4 for combustion turbines is use of clean low sulfur fuel (e.g., natural gas). The H_2SO_4 emission calculation needs to allow for a reasonable variation in the sulfur content of pipeline natural gas, which is outside the control of a given generation facility, and oxidation of SO_2 to SO_3 oxidation from a CO catalyst. The Applicant proposes a H_2SO_4 limit for the Project (0.0010 lb/MMBtu), which is consistent with recent PSD BACT precedents which properly account for these variables.

Table 4-2. Summary Of Recent H_2SO_4 PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Sulfuric Acid Mist (H_2SO_4)
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	0.0012 lb/MMBtu without DF 0.0016 lb/MMBtu with DF
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: 0.00041 lb/MMBtu without DF Mitsubishi: 0.00044 lb/MMBtu with DF Siemens: 0.0006 lb/MMBtu without DF Siemens: 0.0007 lb/MMBtu with DF
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	GE7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H. 2 combined cycle units	0.92 lb/hr/unit without DF 1.08 lb/hr/unit with DF Emissions based on Siemens SGT6-8000H
Sunbury Generation	Sunbury, PA	04/01/2013	"F Class" with DF 2538 MMBtu/hr/unit	0.0018 lb/MMBtu 4.4 lb/hr/unit without DF 4.7 lb/hr/unit with DF
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	0.00058 lb/MMBtu without DF 0.00067 lb/MMBtu with DF
Moxie Patriot LLC	Clinton Twp, PA	01/31/2013	Equipment type not specified 2 - 472 or 458 MW combined cycle blocks with DF	0.0005 lb/MMBtu
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA 309 MW	6.5 lb/hr
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	4 - "F Class" (GE or Siemens) 1345 MW total	0.75 grains S/100 scf of natural gas
Hess Newark Energy	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	1.36 lb/hr/unit without DF 1.33 lb/hr/unit with DF
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	4.8 lb/hr/unit
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Equipment type not specified 2 – 468 or less MW combined cycle blocks GT $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 3870 MMBtu/hr/unit	0.0002 lb/MMBtu 1.4 lb/hr for 454 MW block 1.5lb/hr for 468 MW block
Cricket Valley	Dover, NY	09/27/2012	3 - GE 7FA.05 2061 MMBtu/hr/unit plus 379 MMBtu/hr DF	0.5 grains S/100 scf of natural gas

Table 4-2. Summary Of Recent H_2SO_4 PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2]
				Sulfuric Acid Mist (H_2SO_4)
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	4.89 lb/hr/unit
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	0.0018 lb/MMBtu 3.6 lb/hr
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	13.68 lb/hr
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	1 - Mitsubishi M501GAC 2866 MMBtu/hr	1.5 lb/MMcf (0.0015 lb/MMBtu)
Dominion Warren County	Front Royal, VA	12/21/2010	3 -Mitsubishi M501 GAC 2996 MMBtu/hr/unit plus 500 MMBtu/hr DF	0.00013 lb/MMBtu without DF 0.00025 lb/MMBtu with DF
Pondera/King Power Station	Houston, TX	08/05/2010	4 GE 7FA.05 2430 MMBtu/hr/unit GT plus DF or 4 Siemens SGT6-5000F5 2693 MMBtu/hr/unit GT plus DF	GE: 3.37 lb/hr/unit (w/ and w/o DF) Siemens: 3.77 lb/hr/unit (w/ and w/o DF)
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	No emission limits specified. PSD BACT for H_2SO_4 use of pipeline quality natural gas with $\leq$ 0.5 grains S/100 scf
Panda Sherman Power	Grayson, TX	02/03/2010	2 GE 7FA 170 MW/unit plus 570 MMBtu/hr DF or 2 Mitsubishi M501G 254 MW/unit plus 230 MMBtu/hr DF	GE: 0.56 lb/hr/unit (w/ and w/o DF) Mitsubishi: 0.62 lb/hr/unit (w/ and w/o DF)
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 – GE 7FA, GE7FB, or Siemens SGT6-5000F With DF	GE: 1.9 lb/hr/unit (w/ and w/o DF) Mitsubishi: 2.0 lb/hr/unit (w/ and w/o DF)
Entergy Lewis Creek Plant	The Woodlands, TX	05/19/2009	2 - GE 7FA with 362 MMBtu/hr DF	4.03 lb/hr/unit

[1] DF refers to duct firing

[2] Limits obtained from agency permitting documents when not available in RBLC. Short-term emission limits only are provided.

4.1.5 Best Available Control Technology Assessment for Greenhouse Gases

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). 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 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

<u>Low Carbon-Emitting Fuels</u>

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 Project 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 Project.

<u>Energy Efficiency and Heat Rate</u>

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, a boiler-based steam electric unit is less efficient than a combustion turbine combined cycle unit. This is because the combustion energy from a combustion turbine is directly imparted onto the turbine blades, and a combined cycle unit then uses the waste heat from the combustion turbine exhaust to generate additional power, utilizing a HRSG and subsequent steam cycle.

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 4-1); 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 energy efficiency and heat rate. The Project is already using the lowest carbon fuel and carbon capture and storage is not currently feasible.

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) combusted 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.

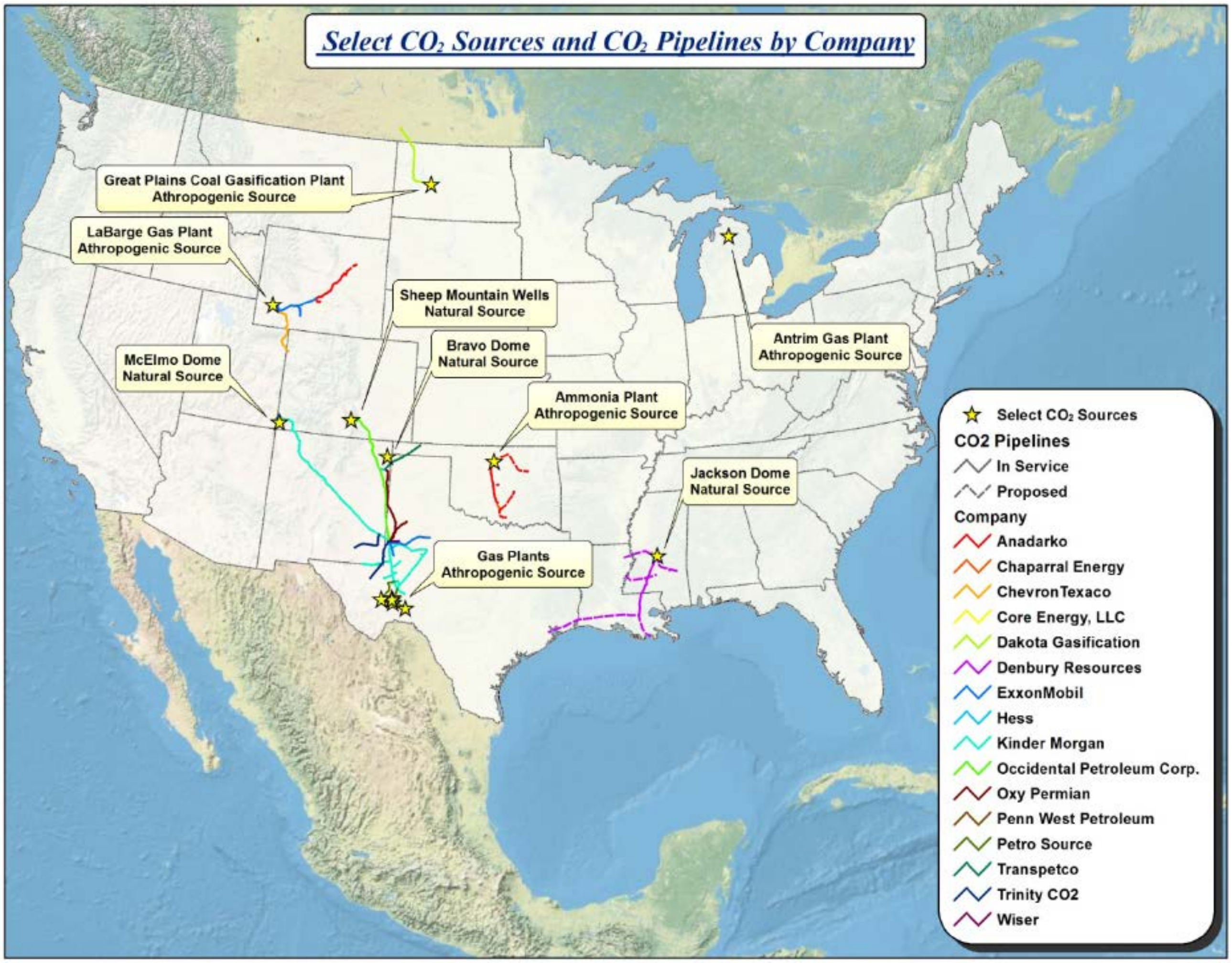

Figure 4-1. CO_2 Pipelines in the United States
From: "Report of the Interagency Task Force on Carbon Capture and Storage," August 2010, Appendix B.

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. Seawater can potentially be used for makeup to a wet evaporative system, but this is is a very challenging application. The most likely candidate source for the volumes of cooling tower makeup water required would be the SESD sewage treatment plant. 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 typical chemical constituents in the effluent and the likely highly variable concentrations of certain of these constituents would place a burden on the Project. 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.

The Administration Building has been designed to meet the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) at the Platinum level. The Administration Building, as well as the Operations Building, among various energy conservation features, incorporate green roofs, geothermal heat pumps for heating and cooling, building energy management systems, and a 10% reduction in lighting power density.

Step 5: Select BACT

The Project has proposed GHG limits as follows for the combined cycle units:

- Initial test limit of 825 lb CO_2e/MWhr (net to grid), full load, ISO corrected, without duct firing
- Rolling 365-day GHG BACT limit (life of facility) of 895 lb CO_2e/MWhr (net to grid)

For purposes of comparison, the initial test GHG limit of 825 lb CO_2e/MWhr (net to grid) corresponds to a "heat rate" of 6,940 Btu HHV/kWhr (net). On a "gross" energy basis, these values are 795 lb CO_2e/MWhr (gross) and 6,688 Btu HHV/kWhr (gross). The rolling 365-day GHG BACT limit of 895 lb CO_2e/MWhr (net to grid) corresponds to a "heat rate" of 7,521 Btu HHV/kWhr (net). On a "gross" energy basis, these values are 862 lb CO_2e/MWhr (gross) and 7,247 Btu HHV/kWhr (gross).

Note that "gross" energy is based on the full electric energy output of the generation equipment, without consideration of internal plant loads (parasitic losses such as for pumps and fans). Net energy is based on the amount of electric energy after internal plant demand is satisfied, and reflects the amount of energy actually sold to the electric grid.

For purposes of comparison with other projects, Footprint's design thermal efficiency is 57.9%. This is based on ISO full load operation, without duct firing or evaporative cooling, without any degradation allowance, and reflects gross energy output fuel energy input based on LHV. This is the most typical way that thermal efficiency is reported. This is not as meaningful for purposes of GHG BACT limits compared to measures based on net power production, since those based on net power account for the project internal energy consumption. Footprint considers the proposed rolling 12-month CO_2e limit for the life of the project as the most meaningful limit since it reflects actual long-term emissions, and actual power delivered to the grid.

Pursuant to supporting these proposed limits consistent with the "top-down" procedure, Footprint has compiled PSD BACT determinations for GHG in the last five years for new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on all entries during this time period listed in the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. This review confirms that the only BACT technology identified for large natural gas fired combined cycle turbines is use of low carbon fuel (i.e., natural gas) in high efficiency combined cycle units. There are no cases where any post combustion controls (carbon capture and sequestration) have been used to control GHG emissions from large natural gas fired combined cycle turbines.

Table 4-3 presents the results of RBLC compilation for GHG. GHG BACT emissions are expressed in varying units, including mass emission (tons or pounds per unit time), lb CO_2e per MWhr, and/or "heat rate" (Btu/kWhr). The energy-based limits are expressed as either "gross" or "net". Energy units (MWhr or kWhr) or more meaningful than mass emission limits since they relate directly to the efficiency of the equipment, which is a key available BACT technology (in addition to low carbon fuel). The mass emissions are specific to the fuel firing rate of a given project and the carbon content of the fuel, but do not incorporates the project efficiency.

Table 4-3 lists 15 projects with PSD BACT limits for GHG approved in the last 5 years which have energy based GHG limits. (The mass limit projects are not considered since they are not meaningful for GHG BACT comparison). Accounting for the different units for these limits, the Footprint Project proposed GHG limits are clearly more stringent than most of the energy based limits in Table 4-3. For limits where this comparison is not clear, the following clarifications are made:

- The basis for Oregon (OH) Clean Energy project limits (840 and 833 lb/MWhr gross) is not clear, but the context of this actual permit suggests these limits are intended for ISO conditions without duct firing which makes them less stringent than the Footprint limits.

- The Brunswick County limit of 7,500 Btu/kWhr net *at full load* with duct firing does not directly correspond to either of the Footprint conditions. However, Footprint's limit of 895 lb CO_2e/MWhr corresponds to a rolling 365-day value of 7,521 Btu/kWhr net which accounts for all operation on an annual basis including starts, stops, and part load in addition to duct firing.

- The Palmdale project limits of 774 lb/MWhr and 7,319 Btu/kWhr (source wide net 365 day average limits) are more stringent than the Footprint limits. However, the Palmdale project is a

Table 4-3. **Summary Of Recent GHG PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants**

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Greenhouse Gas (GHG) as CO2e unless otherwise noted
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	859 lb/MWhr gross at ISO conditions without duct firing
Renaissance Power	Carson City, MI	11/1/2013	4 Siemens 501 FD2 units 2147 MMBtu/hr/unit each with 660 MMBtu/hr DF	1000 lb/MWhr gross 12-month rolling average
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: 840 lb/MWhr gross Siemens: 833 lb/MWhr gross
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	2 GE 7FA.05 2230 MMBtu/hr/unit plus 650 MMBtu/hr DF or 2 Siemens SGT6-5000F5 2260 MMBtu/hr/unit plus 450 MMBtu/hr DF	Heat rate of 7,340 Btu HHV/kWhr gross without DF Heat rate of 7,780 HHV Btu/kWhr gross with DF
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	GE7FA, Siemens SGT6-5000F, Mitsubishi M501G, or Siemens SGT6-8000H. 2 combined cycle units	3,665,974 tpy both units Emissions based on Siemens SGT6-8000H
Sunbury Generation	Sunbury, PA	04/01/2013	"F Class" with DF 2538 MMBtu/hr/unit	281,727 lb/hr without DF 298,106 lb/hr with DF
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	Heat rate of 7,500 Btu(HHV)/kWhr net; tested at full load and corrected to ISO conditions with DF
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA with DF 309 MW	Heat rate of 7,717 Btu HHV/kWhr net 12-month rolling average
St. Joseph Energy center	New Carlisle, IN	12/03/2012	4 - "F Class" (GE or Siemens) 1345 MW total	Heat rate of 7,646 Btu/kWhr. Further detail not specified
Hess Newark Energy	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	887 lb/MWhr gross 12-month rolling average Heat rate of 7,522 Btu(HHV)/kWhr; net basis at full load and corrected to ISO conditions without DF
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	920 lb/MWhr net
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Equipment type not specified 2 – 468 or less MW combined cycle blocks GT $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 3870 MMBtu/hr/unit	1,388,540 tpy for 454 MW block 1,480,086 tpy for 468 MW block

Table 4-3. Summary Of Recent GHG PSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] Greenhouse Gas (GHG) as CO2e unless otherwise noted
Cricket Valley	Dover, NY	09/27/2012	3 - GE 7FA.05 2061 MMBtu/hr/unit plus 379 MMBtu/hr DF	Heat rate of 7,605 Btu HHV/kWhr ISO without DF 57.4% design thermal efficiency 3,576,943 tpy all 3 units
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	920 lb/MWhr net
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	825 lb/MWhr net (initial full load test corrected to ISO conditions) 895 lb/MWhr net (rolling 365-day average)
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	2 GE 7FA 154 MW (1736 MMBtu/hr) per unit plus 500 MMBtu/hr DF	774 lb/MWhr source wide net 365 day rolling average (CO2) Heat rate: 7,319 Btu/kWhr source wide net 365 day rolling average
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	908,957.6 lb/hr 30-day rolling average
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	1 Siemens SGT6-PAC-5000F 2227 MMBtu/hr plus 641 MMBtu/hr DF	870 lb CO2e/MWhr monthly average 842 lb/MWhr rolling 12-month average 1,094,900 tpy
Russell City Energy Center	Hayward, CA	02/03/2010	2 - Siemens 501F 2238.6 MMBtu/hr/unit plus 200 MMBtu/hr DF	Heat rate of 7,730 Btu HHV/kWhr 242 metric tons of CO2e/hr/both units 5,802 metric tons of CO2e/day/both units 1,928,102 metric tons of CO2e/year/both units 119 lb CO2e/MMBtu

[1] DF refers to duct firing
[2] Limits obtained from agency permitting documents when not available in RBLC

hybrid solar/gas turbine project, and the Palmdale GHG limits appear to account for the solar energy production component. The Footprint Project's available land and Massachusetts climate restrictions preclude a solar component which could achieve the Palmdale limits.

- The Brockton (MA) Project was approved for a rolling 12-month CO_2 limit of 842 lb/MWhr, and a monthly maximum of 870 lb/MWhr. The basis for the 842 lb/MWhr limit in the Massachusetts Plan Application for the Brockton Project is stated *to include operation at a variety of loads, ambient temperatures, with and without evaporative cooling, and with and without duct firing, and including starts and stops* (Brockton Power Plan Application at page 4-30). However, there is no mention of any allowance for heat rate (efficiency) degradation over the life of the project or between major turbine overhauls. This is a significant consideration which renders this value of 842 lb CO_2/MWhr as inappropriate as a GHG BACT precedent. Footprint notes that the Brockton Project has not been constructed, and the 842 lb/MWhr value therefore has not been demonstrated in practice. In addition, the Footprint notes that the Brockton Project did not specifically undergo a PSD review for GHG BACT. Footprint also notes that in the Plan Application for the Brockton Project, it is stated that the 842 lb/MWhr value is based on a CO_2 emission factor of 117 lb/MMBtu. Footprint notes its proposed limit of 895 lb/net MWhr is based on a CO_2e emission factor of 119 lb/MMBtu. Adjusting the Brockton value of 842 lb/MWhr by 119/117, the Brockton rate (based on 119 lb CO_2/MMBtu) would be 856 lb/MWhr. In this case, the Footprint Project value (895 lb/MWhr) is only 4.6% higher than the adjusted Brockton value (856 lb/MWhr). In addition, the Brockton Project design is based on wet cooling, while the Footprint Project will use dry cooling. Projects using dry cooling have higher heat rates (are less efficient) than wet cooled projects, particularly during the summer months. Reasonable allowance for heat rate (efficiency) degradation over the life of the project and between major turbine overhauls, as well as the impact of wet vs. dry cooling, explains the proposed GHG BACT for the SHR Project of 895 lb/net MWhr compared to the proposed Brockton limit.

CLF comments dated November 1, 2013 on the Footprint public review documents indicate that the Newark Energy Center has a combined cycle mode heat rate limit of 6005 Btu/kWhr, corresponding to a thermal efficiency of 58.4%. The CLF comments further note that the Russell Energy Center Project in CA has proposed to achieve a thermal efficiency of 56.4%, and the Cricket Valley Project (NY) proposed to achieve 57.4% efficiency. These values are taken from a letter written by Steve Riva dated April 17, 2012.

The Newark Energy Center quoted values of 6005 Btu/kWhr and 58.4% thermal efficiency appear to be preliminary values, since they do not match the actual New Jersey PSD Permit as discussed below. When comparing heat rate and efficiency values, these may be quoted with varying assumptions, and it is important to ensure an "apples to apples" comparison is made. The heat rate used to calculate thermal efficiency is typically specified based on full load ISO operation, no duct firing, gross output, and on an LHV basis. That is why it is commonly a lower value than "real world" rolling 12-month, net, HHV values. These two values (6005 Btu/kWhr and 58.4% thermal efficiency) are actually not consistent with each other, since thermal efficiency is calculated as 3412 Btu/kW-hr/6005 Btu/kW-hr = 56.8% thermal efficiency. In any event, the "real" numbers for the Newark Energy Center GHG BACT limits in Table 4-3 are taken from the actual New Jersey PSD permit dated November 1, 2012, so these represent more recent information for the Newark Energy Center Project. The actual Newark Energy Center permit has net "heat" rate limit (without duct firing at base load corrected to ISO conditions) of 7,522 Btu/kWhr based on the Higher Heating Value (HHV) of the fuel. As indicated above, the Footprint Project has a nearly numerically identical rolling 365-day GHG limit which corresponds to a net heat rate of 7,521 Btu/kWhr, but that reflects *all* annual operation and not just base load without duct firing. The Newark Energy Center also has a direct GHG limit of 887 lb/MWhr, gross basis, rolling 12-month average. The Footprint rolling 365-day GHG limit of 895 lb/MWhr *net basis* is clearly more stringent than the actual Newark Energy Center GHG limit.

The Russell Energy Center PSD Permit has a heat rate limit of 7,730 Btu/kW-hr, with the key assumptions for calculating compliance not specified. In any event, this limit is clearly less stringent than Footprint's rolling 365-day GHG limit which corresponds to a net heat rate of 7,521 Btu/kWhr. Footprint's design thermal efficiency of 57.9% is also better than the quoted Russell proposal of 56.4% (not referenced in the Russell's actual PSD permit).

Cricket Valley's PSD permit does contain the quoted 57.4% thermal efficiency, and well as a heat rate limit of 7,605 Btu/kW-hr. The Cricket Valley PSD permit indicates this heat rate is at ISO conditions, HHV without duct firing. Gross or net electric output is not specified. As with Russell, this limit is clearly less stringent than Footprint's rolling 365-day GHG limit which corresponds to a net heat rate of 7,521 Btu/kWhr. Footprint's design thermal efficiency of 57.9% is also better than the Cricket Valley value 57.4%.

CLF suggests that the GHG limits should also be expressed on a thermal efficiency basis. As stated above, thermal efficiencies for gas turbines are normally based on the lower heating value (LHV) of the fuel, on a gross energy basis. The only PSD Permit we identified containing a thermal efficiency value is the Cricket Valley PSD permit. As MassDEP has done, Footprint concurs it is more appropriate to propose GHG limits directly as CO_2e on a *net* energy basis, accounting for actual emissions of GHG and overall project efficiency including parasitic plant loads.

In summary, the available evidence clearly indicates that PSD BACT for GHG for combustion turbines is use of low carbon fuel (e.g., natural gas) in high efficiency combustion combined cycle turbines. Footprint's proposed GHG limits are as or more stringent than any PSD BACT determinations, except for a hybrid solar facility, and the Brockton Power Project, which has a rolling 12-month limit which does not properly account for degradation over the life of the equipment. It is concluded that Footprint's proposed GHG limits represent PSD BACT.

4.1.6 Combustion Turbine Startup and Shutdown BACT

This section supplements the PSD BACT analysis for the combustion turbine startup and shutdown (SUSD) limits. Combustion turbine combined cycle units require warm up time to achieve proper operation of the dry-low NO_x combustors discussed above, and also to achieve system warm-up to allow proper function of the SCR catalysts. Combustion turbine combined cycle units require higher mass emission limits during SUSD operations for NO_x, CO and VOC. Since CO and VOC are not subject to PSD review, this SUSD BACT assessment only addresses NO_x. The other pollutants subject to PSD review are $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, as these pollutants have lower mass emissions than for normal operation and thus are not included in this PSD SUSD BACT evaluation. GHG also has the rolling 12-month limit (lb/MWhr) encompassing all operation including SUSD.

This evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for SUSD are procedures to warm up the systems and begin operation of the temperature-dependent emission control systems as quickly as practical, consistent with all system constraints. The Project incorporates new "quick start" technology which minimizes SUSD emissions significantly compared to prior startup procedures in widespread use. Table 4-4 presents the proposed NOx SUSD BACT limits for the Project:

Table 4-4. Combustion Turbine NOx SUSD PSD BACT Limits

Pollutant	Startup (lb/event)	Shutdown (lb/event)
NOx	89	10

In addition to these limits, the Project has a limit for startup duration of ≤ 45 minutes and for shutdown duration of ≤ 27 minutes. Also, the project is required to begin SCR operation (inject ammonia) as soon as the systems attain the minimum temperatures as specified by the control equipment system vendors, and other system parameters are satisfied for SCR operation.

As part of the review of these proposed NO_x SUSD BACT limits under the "top-down" procedure, Footprint has compiled all the NO_x SUSD PSD BACT determinations in the last five years for new gas-fired large (> 100 MW) combustion turbine combined cycle projects. This compilation is presented in Table 4-5. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. This review confirms that the only SUSD NO_x BACT technologies identified are procedures to warm up the systems and begin operation of the SCR as quickly as practical consistent with other constraints. Table 4-5 contains 28 new large (> 100 MW) combustion turbine combined cycle projects with NO_x SUSD PSD BACT determinations. These limits are generally expressed as either lb/hr or lb/event. Some units do not have numerical SUSD limits for NO_x, but only requirements to minimize SUSD emissions.

For purposes of comparing the Project limits to determinations only expressed in lb/hr, Footprint's worst case lb/hr is calculated as 45 minutes for a cold start (at 89 pounds) plus 15 minutes at full load (18.1 lb/hr)/4 = 93.5 lb/hr. Also, while the Project's proposed NO_x SUSD limits for a start are only for a worst-case cold start, for comparison purposes the Project's values for a warm and hot start, as provided in the August 6, 2013 Application Supplement, are 54 and 28 pounds, respectively.

All the NO_x SUSD BACT limits in Table 4-5 are less stringent than the Footprint limits, except for the warm start limits at two CA projects (Palmdale and Victorville), and startup/shutdown limits for the Brockton MA Project. Palmdale and Victorville each have the same limit for a warm and hot start of 40 lbs/event, while the Footprint values are 54 lbs for a warm start and 28 lbs for a hot start. It is logical that a warm start would have higher emissions than a hot start, and the average of the two Footprint values (54 lbs and 28 lbs) is 41 lbs/event, effectively identical to the Palmdale and Victorville value.

The Brockton project is based on a "quick start" Siemens SGT6-PAC-5000F combined cycle installation, and has approved SUSD limits of 31.6 lb/hr (startup) and 29.8 lb/hr (shutdown). The startup time is stated as 0.47 hours and the shutdown time is 0.40 hours. Thus, the lb/event values are calculated as 14.9 pounds for a start and 11.9 pounds for a shutdown. Footprint did consider a very similar Siemens turbine subsequent to the approval data of the Brockton permit, and this more recent data for the same basic "quick start" Siemens machine (5000F) now has 83 lbs NO_x over 45 minutes. For a combined cold start and shutdown, Footprint now has (89 +10 = 99) lbs NO_x while the Siemens data provided to Footprint reflects (83 + 20 = 103) lbs NO_x. GE has lower NO_x emissions for both the warm and hot start. So, based on the latest information, there is no advantage to selecting Siemens over GE for NO_x startup/shutdown emissions based on more recent data.

Table 4-5. Summary Of Recent NOx SUSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] SUSD NOx (values are for a single unit at multiple unit facilities)
Carroll County Energy	Washington Twp., OH	11/5/2013	2 GE 7FA 2045 MMBtu/hr/unit plus 566 MMBtu/hr DF	Cold Start: 476 lbs/event Warm Start: 290 lbs/event Hot Start: 160 lbs/event Shutdown: 77 lbs/event Values calculated from approved lb/hr and event durations
Renaissance Power	Carson City, MI	11/1/2013	4 Siemens 501 FD2 units 2147 MMBtu/hr/unit each with 660 MMBtu/hr DF	176.9 lb/hr SU and 147.3 lb/hr SD
Langley Gulch Power	Payette, ID	08/14/2013	1 - Siemens SGT6-5000F 2134 MMBtu/hr/unit with 241.28 MMBtu/hr DF	96 ppm; 3 hr rolling average *(for the amount of fuel firing during SUSD for a GE 7FA, 96 ppm corresponds to approximately 450 lbs over a 45 minute quick start)*
Oregon Clean Energy	Oregon, OH	06/18/2013	2 Mitsubishi M501GAC or 2 Siemens SCC6-8000H 2932 MMBtu/hr/unit plus 300 MMBtu/hr DF	Mitsubishi: Cold Start: 108.9 lbs/event Warm Start: 86 lbs/event Hot Start: 47.2 lbs/event Shutdown: 35 lbs/event Siemens: – Cold Start: 188 lbs/event Warm Start: 126 lbs/event Hot Start: 108 lbs/event Shutdown: 46 lbs/event Values calculated from approved lb/hr and event durations
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	2 GE 7FA.05 2230 MMBtu/hr/unit plus 650 MMBtu/hr DF or 2 Siemens SGT6-5000F5 2260 MMBtu/hr/unit plus 450 MMBtu/hr DF	Minimize emissions, No numeric limits
Brunswick County Power	Freeman, VA	03/12/2013	3 Mitsubishi M501 GAC with DF Combined GT and DF 3442 MMBtu/hr/unit	Minimize emissions, No numeric limits
Garrison Energy Center	Dover, DE	01/30/2013	GE 7FA 309 MW	Cold Start/: 500 lbs/event Warm/Hot Start/: 200 lbs/event Shutdown: 23 lbs/event
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	4 - “F Class” (GE or Siemens) 1345 MW total	443 lb/event

Table 4-5. Summary Of Recent NOx SUSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] SUSD NOx (values are for a single unit at multiple unit facilities)
Hess Newark Energy Center	Newark, NJ	11/01/2012	2 - GE 7FA.05 2320 MMBtu/hr/unit plus 211 MMBtu/hr DF	Cold Start: 140.6 lbs/event Warm Start: 96.8 lbs/event Hot Start: 95.2 lbs/event Shutdown: 25 lbs/event
Channel Energy Center, LLC	Houston, TX	10/15/2012	2 - Siemens 501F 180 MW plus 425 MMBtu/hr DF	350 lb/hr
Moxie Liberty LLC	Asylum Twp., PA	10/10/2012	Siemens “H Class” 2 – 468 or less MW combined cycle blocks GT $\leq$ 2890 MMBtu/hr/unit DF $\leq$ 3870 MMBtu/hr/unit	No SUSD listed in RBLC
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	1 - Siemens 501F 180 MW plus 725 MMBtu/hr DF	350 lb/hr
ES Joslin Power	Calhoun, TX	09/12/2012	3 - GE 7FA 195 MW per unit No DF	99.9 lb/hr
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	1 Mitsubishi M501GAC 2542 MMBtu/hr/unit; no DF	62 lb/hr (310 lbs/event for cold start) (124 lbs/event for warm start (62 lbs/event for shutdown)
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	2 GE 7FA 154 MW (1736 MMBtu/hr) per unit plus 500 MMBtu/hr DF	Cold Start: 96 lbs/event Warm/Hot Start: 40 lbs/event Shutdown: 57 lbs/event
Thomas C. Ferguson Power	Llano, TX	09/01/2011	2 - GE 7FA 195 MW per unit No DF	111.56 lb/hr
Entergy Ninemile Point Unit 6	Westwego, LA	08/16/2011	Vendor not specified Single unit 550MW	No SUSD in RBLC
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	1 Siemens SGT6-PAC-5000F 2227 MMBtu/hr plus 641 MMBtu/hr DF	Start: 31.6 lb/hr Shutdown: 29.8 lb/hr
Avenal Power Center	Avenal, CA	05/27/2011	2 - GE 7FA 1856.3 MMBtu/hr/unit plus 562.26 MMBtu/hr DF	Each unit: 160 lb/hr Both units: 240 lb/hr

Table 4-5. Summary Of Recent NOx SUSD BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Turbine[1]	Emission Limits[2] SUSD NOx (values are for a single unit at multiple unit facilities)
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	1 - Mitsubishi M501GAC 2866 MMBtu/hr	150 lb/hr; 3-hr rolling average
Dominion Warren County	Front Royal, VA	12/21/2010	3 -Mitsubishi M501 GAC 2996 MMBtu/hr/unit plus 500 MMBtu/hr DF	Minimize emissions, No numeric limits
Pondera/King Power Station	Houston, TX	08/05/2010	4 GE 7FA.05 2430 MMBtu/hr/unit GT plus DF or 4 Siemens SGT6-5000F5 2693 MMBtu/hr/unit GT plus DF	GE: 216 lb/hr/unit Siemens: 220 lb/hr/unit
Live Oaks Power	Sterling, GA	03/30/2010	Siemens SGT6-5000F	Minimize emissions, No numeric limits
Victorville 2 Hybrid	Victorville, CA	03/11/2010	2 GE 7FA 154 MW per unit plus 424.3 MMBtu/hr DF	Cold Start: 96 lbs/event Warm/Hot Start: 40 lbs/event Shutdown: 57 lbs/event
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	2 GE 7FA 170 MW/unit plus 570 MMBtu/hr DF or 2 Mitsubishi M501G 254 MW/unit plus 230 MMBtu/hr DF	GE: 420 lb/hr/unit Mitsubishi: 239 lb/hr/unit
Russell City Energy Center	Hayward, CA	02/03/2010	2 - Siemens 501F 2238.6 MMBtu/hr/unit plus 200 MMBtu/hr DF	Cold Start: 480 lbs/event/unit Warm Start: 125 lbs/event/unit Hot Start: 95 lbs/event/unit Shutdown: 40 lbs/event/unit
Panda Sherman Power	Grayson, TX	02/03/2010	2 GE 7FA or 2 Siemens SGT6-5000F with 468 MMBtu/hr/unit DF	GE: 242 lb/hr/unit Mitsubishi: 148.5 lb/hr/unit
Lamar Power Partners II LLC	Paris, TX	06/22/2009	4 - GE 7FA with 200 MMBtu/hr DF	No SUSD limits in RBLC or TX permit
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 – GE 7FA, GE7FB, or Siemens SGT6-5000F With DF	650 lb/hr/unit (each option)
Entergy Lewis Creek Plant	The Woodlands, TX	05/19/2009	2 - GE 7FA with 362 MMBtu/hr DF	200 lb/hr

[1] DF refers to duct firing: [2] Short-term limits only. Limits obtained from agency permitting documents when not available in RBLC.

PVEC does have a somewhat more stringent NO_x SUSD BACT limit on an hourly basis (62.0 lbs per hour) compared to the equivalent Footprint lb/hr value of 93.5 lbs/hr. However, PVEC has longer startup and shutdown times, with up to 5 hours for a cold start, 2 hours for a warm start, and 1 hour for a shutdown. On a pound per event basis, PVEC has greater SUSD emissions compared to Footprint.

Footprint will achieve the lowest practical emissions achievable for SUSD, and the proposed PSD permit allows the MassDEP to reset the SUSD BACT limits if different values are demonstrated to be achievable.

4.2 Auxiliary Boiler

This section supplements the PSD BACT analysis for the auxiliary boiler to address public comments made on the draft permit documents. The Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus the auxiliary boiler is subject to PSD BACT for these pollutants.

The Project includes an 80 MMBtu/hr auxiliary boiler that will have natural gas as the only fuel of use. Table 4-6 presents the proposed BACT limits for the auxiliary boiler for pollutants subject to PSD review.

Table 4-6. Auxiliary Boiler Proposed PSD BACT Limits

Pollutant	Emission Limitation	Control Technology
NOx	9 ppmvd at 3% O_2 0.011 lbs/MMBtu	Ultra Low NOx Burners (9 ppm) Good combustion practices Natural gas
$PM/PM_{10}/PM_{2.5}$	0.005 lbs/MMBtu	
H_2SO_4	0.0009 lbs/MMBtu	Natural Gas
GHG as CO2e	119.0 lb/MMBtu	Natural Gas

(Note: the H_2SO_4 value is revised to reflect the inclusion of a CO oxidation catalyst)

In order to inform the PSD BACT process, Footprint has compiled all the PSD BACT determinations in the last five years for auxiliary boilers at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 4-7 provides this compilation. Table 4-7 will be referred to in the individual pollutant discussion below.

4.2.1 Fuel Selection

Step 1: Identify Candidate Fuels

- Natural gas
- ULSD

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible.

Step 3: Rank Control Technologies by Control Effectiveness

Natural gas boilers can achieve lower emissions compared to ULSD.

Step 4: Evaluate Controls

Footprint has chosen the lowest emitting fuel for the auxiliary boiler, natural gas. Therefore, a detailed evaluation of alternate fuels is not required.

Step 5: Select BACT

Natural gas is proposed as the BACT fuel for the auxiliary boiler.

Table 4-7. Summary Of Recent PSD BACT Determinations for Natural Gas Auxiliary Boilers at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Auxiliary Boiler Size MMBtu/hr	Emission Limits[1] (lb/MMBtu except where noted) NOx	PM/PM10/PM2.5	H2SO4	GHG
Carroll County Energy	Washington Twp., OH	11/5/2013	99	0.02	0.008	0.00022	26,259.76 tpy
Renaissance Power	Carson City, MI	11/1/2013	(2) - 40	0.035	0.005	--	11,503.7 tpy (both units)
Oregon Clean Energy	Oregon, OH	06/18/2013	99	0.02	0.008	0.00011	11,671 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	75	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	Pipeline natural gas < 0.1 gr S/100scf	--	Pipeline natural gas
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	40	0.011	0.005	0.0005	13,696 tpy
Sunbury Generation	Sunbury, PA	04/01/2013	Not provided (repowered unit)	0.036	0.008	--	--
Brunswick County Power	Freeman, VA	03/12/2013	66.7	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	Pipeline natural gas < 0.4 gr S/100scf	Pipeline natural gas < 0.4 gr S/100scf	Pipeline natural gas
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) - 80	0.032	0.0075	--	81,996 tpy; 80% efficiency
Hess Newark Energy Center	Newark, NJ	11/01/2012	66.2	0.66 lb/hr (based on 0.010 lb/MMBtu)	0.33 lb/hr (based on 0.005 lb/MMBtu)	0.006 lb/hr (=0.0001 lb/MMBtu at full load)	7,788 lb/hr
Channel Energy Center, LLC	Houston, TX	10/15/2012	(3) - 430	21.6 lb/hr/unit (=0.05 lb/MMBtu at full load)	7.8 lb/hr/unit (=0.018 lb/MMBtu at full load)	1.0 lb/hr/unit (=0.002 lb/MMBtu at full load)	--
Cricket Valley	Dover, NY	09/27/2012	60	0.011	0.005	--	--
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	21	0.029	0.0048	0.0005	--
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	110	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	0.33 lb/hr (=0.003 lb/MMBtu at full load)	--	Annual tuneup
Entergy Nine-mile Point Unit 6	Westwego, LA	08/16/2011	338	--	7.6 lb/MMscf (= 0.0076 lb/MMBtu)	--	117 lb/MMBtu

Table 4-7. Summary Of Recent PSD BACT Determinations for Natural Gas Auxiliary Boilers at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Auxiliary Boiler Size MMBtu/hr	Emission Limits[1] (lb/MMBtu except where noted)			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	60	0.011	0.01	--	--
Avenal Power Center	Avenal, CA	05/27/2011	37.4	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	0.34 grains S/100 dscf and pipeline quality gas	--	--
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	91	50 lb/MMscf (= 0.05 lb/MMBtu)	2.5 lb/MMscf (= 0.0025 lb/MMBtu)	--	--
Dominion Warren County	Front Royal, VA	12/21/2010	88.1	0.011 lb/MMBtu	0.44 lb/hr (=0.005 lb/MMBtu at full load)	--	--
Pondera/King Power Station	Houston, TX	08/05/2010	(2) - 45	0.45 lb/hr/unit (=0.01 lb/MMBtu at full load)	0.32 lb/hr/unit (=0.007 lb/MMBtu at full load)	--	--
Victorville 2 Hybrid	Victorville, CA	03/11/2010	35	9 ppmvd at 3% O2 (= 0.011 lb/MMBtu)	0.2 grains S/100 dscf and pipeline quality gas	--	--
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	142	1.42 lb/hr/unit (=0.01 lb/MMBtu at full load)	1.06 lb/hr/unit (=0.0075 lb/MMBtu at full load)	--	--
Panda Sherman Power	Grayson, TX	02/03/2010	53	0.53 lb/hr/unit (=0.01 lb/MMBtu at full load)	0.53 lb/hr/unit (=0.01 lb/MMBtu at full load)	--	--
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	(4) - 40	1.4 lb/hr/unit (=0.01 lb/MMBtu at full load)	0.3 lb/hr/unit (=0.0075 lb/MMBtu at full load)	--	--

[1]Short term limits only for NOx, PM, and H2SO4. Limits obtained from agency permitting documents when not available in RBLC

4.2.2 NOx

Step 1: Identify Candidate Control Technologies

- Selective Catalytic Reduction
- Ultra-Low NOx burner
- Low NOx burner, typically with flue gas recirculation

Step 2: Eliminate Infeasible Technologies

All these technologies are technically feasible, although application of SCR is unusual for natural gas boilers in this size range.

Step 3: Rank Control Technologies by Control Effectiveness

The ranking of these technologies is as follows:

1. SCR: Demonstrated to have achieved less than 5.0 ppmvd NO_x at 3% O_2 for gas fired boilers. Can be used as supplemental control with a low NO_x burner but not demonstrated with an ultra-low-NO_x burner.
2. Ultra-Low NOx burner: Demonstrated to have achieved 9 ppmvd NO_x at 3% O2
3. Low NOx burner, typically with flue gas recirculation: Generally recognized to achieve 30 ppmvd NO_x at 3% O_2.

Step 4: Evaluate Controls

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 4-8. The capital cost estimate for an SCR system and an ultra-low NO_x burner are based on information provided by Cleaver Brooks. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions (to 3 ppmvdc at 3% O_2) even though 5 ppmvdc has been approved in past projects. Control to this NO_x level is likely to correspond to an ammonia slip level of 10 ppm at 3% O_2. Table 4-8 indicates that the average and particularly the incremental cost effectiveness of an SCR are excessive, at over $19,000 per ton for average cost of control, and nearly $70,000 per ton on an incremental basis. The ultra-low-NO_x burner is cost effective and is the proposed BACT. There are no energy or environmental issues with ultra-low NO_x burners that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

Step 5: Select BACT

With respect to NO_x, the lowest limit identified for any of the power plant auxiliary boilers in Table 4-7 is consistent with the standard guarantee for ultra-low-NOx burners, which is 9 ppmvd at 3% O_2. This corresponds to 0.011 lb/MMBtu. There are several boilers with BACT limits for NOx in lb/hr calculated with 0.01 rather than 0.011 lb/MMBtu, but this is considered effectively the same limit at full load and is actually less stringent at part-load, since the limits expressed as 9 ppmvd at 3% O_2/0.011 lb/MMBtu apply throughout the load range. The Project auxiliary boiler meets this most stringent limit found for natural gas-fired auxiliary boilers at new large (> 100 MW) combustion turbine combined cycle projects.

Table 4-8. Summary of Auxiliary Boiler Top-Down BACT Analysis for NOx

Control Alternative	NOx Emissions			Economic Impacts				Energy Impacts (compared to baseline)	Environmental Impacts	
	ppmvd @ 3% O2	Tons per year (tpy)	Emissions Reduction Compared to Baseline (tpy)	Installed Capital Cost (differential over baseline)	Total Annualized Cost (differential over baseline)	Average Cost Effectiveness	Incremental Cost Effectiveness		Toxics Impacts (Yes/No)	Adverse Environmental Impacts (Yes/No)
SCR	3	0.95	8.51	$414,750	$162,668	$19,115	$69,786	Small	Yes	No
ULN	9	2.89	6.57	$134,400	$27.283	$4,153	--	negligible	No	No
LN (baseline)	30	9.46	--	--	--	--	--			

SCR – Selective Catalytic Reduction
ULN – Ultra low-NOx burner
LN – Low NOx burner

See Appendix A, Calculation Sheets 8 and 9, for calculation of cost values.

4.2.3 $PM/PM_{10}/PM_{2.5}$

For $PM/PM_{10}/PM_{2.5}$, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion control technologies available for $PM/PM_{10}/PM_{2.5}$. The "top-down" procedure does require selection of BACT emission limits, which is addressed in the following paragraphs.

Table 4-7 presents the review of BACT precedents for auxiliary boilers. With respect to $PM/PM_{10}/PM_{2.5}$, for limits expressed in mass units (lb/MMBtu or lb/hr converted to lb/MMBtu at full load), only two of the auxiliary boilers listed in the Table 4-7 have $PM/PM_{10}/PM_{2.5}$ limits that are more stringent than the Project auxiliary boiler limit of 0.005 lb/MMBtu. One of these boilers is at the Palmdale Hybrid Power facility, with a limit of 0.33 lb/hr, which corresponds to 0.003 lb/MMBtu at full load. However, this lb/hr limit could be met by reducing the boiler load, if the actual emissions exceed 0.003 lb/MMBtu. So at lower loads it is actually less stringent than the Project limit of 0.005 lb/MMBtu, which applies throughout the load range. The other boiler listed in the RBLC with a lower lb/MMBtu emission limit is at the Portland (OR) General Electric Carty Plant. This limit of 2.5 lb/MMcf of natural gas (which corresponds to 0.0025 lb/MMBtu) is considered unrealistically low for a guarantee for a boiler of this type. This is because of uncertainty and variability with available $PM/PM_{10}/PM_{2.5}$ test methods, and the risk of artifact emissions resulting in a tested exceedance. All new gas-fired boilers, properly operated, are expected to have intrinsically low $PM/PM_{10}/PM_{2.5}$ emissions. A limit of 0.005 lb/MMBtu is within the range of recent PSD BACT levels and is justified as PSD BACT.

Several of the boilers listed in Table 4-7 have $PM/PM_{10}/PM_{2.5}$ PSD BACT limits expressed as the sulfur content of the natural gas. These values range from 0.1 grains/100 scf to 0.4 grains/100 scf. All of these values are lower than what USEPA defines as the maximum sulfur content of pipeline natural gas (0.5 grains/100 scf). The Applicant does not believe it is prudent to assume a natural gas sulfur content lower than EPA's definition for pipeline natural gas. Therefore, these sulfur limits for $PM/PM_{10}/PM_{2.5}$ PSD BACT limits are not appropriate.

4.2.4 H_2SO_4

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of natural gas as the BACT fuel, this is the lowest sulfur content fuel suitable for the auxiliary boiler.

The BACT process for H_2SO_4 proceeds directly to the selection of BACT. Footprint has based the H_2SO_4 limit on 40% molar conversion of fuel sulfur to H_2SO_4. This is because Footprint has incorporated a CO oxidation catalyst to reduce CO emissions. One of the collateral impacts of this oxidation catalyst is an increase in H_2SO_4 emissions. With respect to H_2SO_4, none of the 6 of the projects in Table 4-7 with numeric H_2SO_4 limits have oxidation catalysts. Therefore, the proposed Project limit is less stringent than 5 of these 6 limits. The proposed Project limit of 0.0009 lb/MMBtu H_2SO_4 is justified as PSD BACT with the addition of a CO catalyst.

4.2.5 GHG

For GHG, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion controls suitable for GHG. The BACT process for GHG proceeds directly to the selection of BACT.

With respect to GHG, most of the auxiliary boilers listed in Table 4-7 with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. For its proposed GHG limit for the Auxiliary Boiler, the Project has chosen a conservative value based on the USEPA Part 75 default emission factor (119 lb/MMBtu). Another unit listed in the RBLC has an 80% efficiency specified in addition to an annual mass limit. This is the only auxiliary boiler approved with this type of limit. The Project will install an auxiliary boiler with a nominal efficiency of 83.7%. The Applicant proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (119 lb/MMBtu) as most appropriate PSD BACT limit.

4.3 Emergency Diesel Generator

This section supplements the PSD BACT analysis for the emergency diesel generator to address public comments made on the draft permit documents. The Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus the emergency diesel generator is subject to PSD BACT for these pollutants.

The Project includes a 750 kW emergency diesel generator that will have ultra-low sulfur diesel (ULSD) as the only fuel of use. Table 4-9 presents the proposed BACT limits for the emergency diesel generator for pollutants subject to PSD review.

Table 4-9. Emergency Diesel Generator Proposed PSD BACT Limits

Pollutant	Emission Limitation (grams/kWhr)	Emission Limitation (grams/hphr)
NOx	6.4	4.8
$PM/PM_{10}/PM_{2.5}$	0.20	0.15
H_2SO_4	0.0009 lb/hr (0.00012 lb/MMBtu)	
GHG as CO2e	162.85 lb/MMBtu	

The proposed PSD BACT limits for NO_x and $PM/PM_{10}/PM_{2.5}$ are based on compliance with the EPA New Source Performance Standards (NSPS), 40 CFR 60 Subpart IIII. For a 750 kW engine, Subpart IIII requires what is referred to as a Tier 2 engine. For H_2SO_4, the PSD BACT limit is based on use of ultra-low sulfur diesel (ULSD) fuel, and conversion of 5% of the fuel sulfur on a molar basis to H_2SO_4. The GHG limit is based on EPA emission factors for ULSD.

In order to inform the PSD BACT process, Footprint has compiled all the PSD BACT determinations in the last five years for emergency generators at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 4-10 provides this compilation. Review of Table 4-10 indicates that only one emergency generator is fired with natural gas, and all the others are fired with ULSD. The gas-fired engine, at Avenal Power Center in CA, does have SCR to control NOx. All other emergency generators in Table 4-10 do not have any post combustion controls for PSD pollutants. Table 4-10 will be referred to in the individual pollutant discussion below.

Table 4-10. Summary Of Recent PSD BACT Determinations for Emergency Generators at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Carroll County Energy	Washington Twp., OH	11/5/2013	1112 kW	Subpart IIII		0.000132 grams/kWhr	433.96 tpy
Renaissance Power	Carson City, MI	11/1/2013	(2) – 1000 kW	Subpart IIII		--	1731.4 tpy (both units)
Langley Gulch Power	Payette, ID	08/14/2013	750 kW	Subpart IIII		--	--
Oregon Clean Energy	Oregon, OH	06/18/2013	2250 kW	Subpart IIII		0.000132 grams/kWhr	877 tpy (87)
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	1500 kW	Subpart IIII		--	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	750 kW	6.0 grams/kWhr	0.25 grams/kWhr	--	80.5 tpy
Brunswick County Power	Freeman, VA	03/12/2013	2200 kW	Subpart IIII		ULSD	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	1472 hp	4.93 grams/hp-hr	0.02 grams/hp-hr	--	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 1006 hp	Subpart IIII		--	1186 tpy
Hess Newark Energy Center	Newark, NJ	11/01/2012	1500 kW	Subpart IIII		--	--
Moxie Liberty LLC	Asylum Twp, PA	10/10/2012		4.93 grams/hp-hr	0.02 grams/hp-hr	--	--
Cricket Valley	Dover, NY	09/27/12	4 Black Start EDGs 3000 kW each	Subpart IIII		--	--
ES Joslin Power	Calhoun, TX	09/12/2012	(2) -EDG	14.11 lb/hr/unit	0.44 lb/hr/unit	--	--
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	2174 kW	Subpart IIII		--	--
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	110	Subpart IIII		--	--

Facility	Location	Permit Date	Emergency Generator Size[1]	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Thomas C. Ferguson Power	Llano, TX	09/01/2011	1340 hp	16.52 lb/hr *(5.5 grams/hp-hr)*	0.55 lb/hr	--	15,314 lb/hr 30 day rolling average 765.7 tpy 365 day rolling average
Entergy Nine-mile Point Unit 6	Westwego, LA	08/16/2011	1250 hp	--	Subpart IIII	--	CO_2e 163.6 lb/MMBtu,
Avenal Power Center	Avenal, CA	05/27/2011	550 kW natural gas engine	SCR to 1 gram/hp-hr	0.34 gram/hp-hr	--	--
Dominion Warren County	Front Royal, VA	12/21/2010	2193 hp	Subpart IIII		--	--
Pondera/King Power Station	Houston, TX	08/05/2010	Size not given	26.61 lb/hr	1.88 lb/hr	--	--
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	3- 2000 kW each	5.45 gm/hp-hr	0.032 gm/hp-hr	--	--
Victorville 2 Hybrid	Victorville, CA	03/11/2010	2000 kW	Subpart IIII		--	--
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	750 hp	23.25 lb/hr (14 grams/hp-hr)	1.65 lb/hr (1.0 grams/hp-hr)	--	--
Panda Sherman Power	Grayson, TX	02/03/2010	Size not given	35.24 lb/hr	0.17 lb/hr	--	--
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	Size not given	18.0 lb/hr	0.5 lb/hr	--	--

[1] Generators are diesel generators except where noted.
[2] Short term limits only for NOx, PM, and H2SO4. Limits obtained from agency permitting documents when not available in RBLC.

4.3.1 Fuel Selection

Step 1: Identify Candidate Fuels

- Natural gas
- ULSD

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although use of natural gas is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

Natural gas engines can achieve lower emissions compared to ULSD.

Step 4: Evaluate Controls

Normally, for an emergency generator, it is very important to have the fuel supply directly available without the possibility of a natural gas supply interruption making it impossible to operate the emergency generator in an emergency. The purpose of the emergency generator is to be able to safely shut the plant down in the event of an electric power outage. So in order to maintain this important equipment protection function, ULSD, which can be stored in a small tank adjacent to the emergency generator, is the fuel of choice. Footprint is not aware of the specific circumstance for the emergency generator fuel selection at Avenal, but Footprint does not believe a natural gas fired generator for the Salem Project is a prudent choice.

Step 5: Select BACT

ULSD is proposed as the BACT fuel for the Project emergency generator.

4.3.2 NO_x

Step 1: Identify Candidate Control Technologies

- Selective Catalytic Reduction
- Low NO_x engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 2 engine for 750 kW unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of SCR is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

SCR can normally achieve 90% remove of NO_x emissions, so it is more effective than the Tier 2 engine design which is based on low-NO_x engine design. However, for an emergency generator, if this unit is used just for short period of test and facility shutdown in an actual emergency, the ability of the SCR to control emissions will be significantly reduced since the engine/SCR takes time to warm up to achieve good NO_x control.

Step 4: Evaluate Controls

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 4-11. The capital cost estimate for an SCR system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions even though this is unlikely in this application. Table 4-11 indicates that the cost effectiveness of an SCR is over $33,000 per ton of NO_x. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely) and 90% NO_x control of the full potential to emit is achieved.

There are no energy or environmental issues with a Tier 2 generator that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for NO_x for the emergency generator, Table 4-10 indicates that compliance with Subpart IIII is the most common limit. Several BACT determinations contain gram/kWhr or gram/hp-hr limits that approximate the Subpart IIII values but do not specifically reference Subpart IIII. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output.

Overall, with the elimination of SCR on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

4.3.3 PM/PM_{10}/$PM_{2.5}$

Step 1: Identify Candidate Control Technologies

- Active Diesel Particulate Filter (DPF)
- Low PM engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 2 engine for 750 kW unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of a DPF is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 2 engine design which is based on low-emission engine design.

Step 4: Evaluate Controls

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 4-12. The capital cost estimate for an active system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. Table 4-12 indicates that the cost effectiveness of an active DPF is over $600,000 per ton of PM/$PM_{10}$/$PM_{2.5}$. This cost is excessive, even if the emergency generator runs the maximum allowable amount of 300 hours per year (unlikely).

TABLE 4-11 750 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION -

BACT Assessment			
Control System Life:	10 years		
Interest Rate:	10.00%	Baseline NOx Emissions per 40 CFR 60 Subpart IIII (tpy)	1.74
Economic Factors from MassDEP Form BWP-AQ-BACT		SCR Control Efficiency (%)	90%
Capital Recovery Factor (CRF)	0.163		

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estimate (Per Milton Cat)		$150,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$7,500
Total Equipment Cost (TEC)			**$157,500**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$12,600
b.	Erection and Handling	(TEC*0.14)	$22,050
c.	Electrical	(TEC*0.04)	$6,300
d.	Piping	(TEC*0.02)	$3,150
e.	Insulation	(TEC*0.01)	$1,575
f.	Painting	(TEC*0.01)	$1,575
Total Direct Installation Cost			**$47,250**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$15,750
b.	Construction/Field Expenses	(TEC*0.05)	$7,875
c.	Construction Fee	(TEC*0.1)	$15,750
d.	Start up	(TEC*0.02)	$3,150
e.	Performance Test	(TEC*0.01)	$1,575
Total Indirect Installation Cost			**$44,100**
Total Capital Cost (TCC)			**$248,850**

Capital Recovery		**$40,563**
Direct Operating Costs		
a.	Ammonia	$2,256
b	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$480
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$480
d	Maintenance Materials = Maintenance Labor	$480
Total Direct Operating Cost		**$960**
Catalyst Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year		
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$576
b.	Property Tax: (TCC*0.01)	$2,489
c.	Insurance: (TCC*0.01)	$2,489
d.	Administration: (TCC*0.02)	$4,977
Total Indirect Operating Cost		**$10,531**
Total Annual Cost		**$52,054**
NOx Reduction (tons/yr)		**1.57**
Cost of Control ($/ton - NOx)		**$33,230**

Note 1: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH_3 injected per pound of NOx removed

TABLE 4-12 750 KW EMERGENCY GENERATOR
ECONOMIC ANALYSIS - ACTIVE DIESEL PARTICULATE FILTER

BACT Assessment			
Control System Life: 10 years			
Interest Rate: 10.00%		Baseline PM Emissions per 40 CFR 60 Subpart IIII (tpy)	0.06
Economic Factors from MassDEP Form BWP-AQ-BACT		DPF Control Efficiency (%)	85%
Capital Recovery Factor (CRF) 0.163			

Equipment Cost (EC)	(Factor)		
a. DPF Capital Cost Estimate (per Milton Cat)		$90,000	
b. Instrumentation (0.10A)		Included	
c. Taxes and Freight	(EC*0.05)	$4,500	
Total Equipment Cost (TEC)		**$94,500**	
Direct Installation Costs			
a. Foundation	(TEC*0.08)	$7,560	
b. Erection and Handling	(TEC*0.14)	$13,230	
c. Electrical	(TEC*0.04)	$3,780	
d. Piping	(TEC*0.02)	$1,890	
e. Insulation	(TEC*0.01)	$945	
f. Painting	(TEC*0.01)	$945	
Total Direct Installation Cost		**$28,350**	
Indirect Installation Costs			
a. Engineering and Supervision	(TEC*0.1)	$9,450	
b. Construction/Field Expenses	(TEC*0.05)	$4,725	
c. Construction Fee	(TEC*0.1)	$9,450	
d. Start up	(TEC*0.02)	$1,890	
e. Performance Test	(TEC*0.01)	$945	
Total Indirect Installation Cost		**$26,460**	
Total Capital Cost (TCC)		**$149,310**	

Capital Recovery	**$24,338**
Direct Operating Costs	
a Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c. Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost	**$720**
DPF Replacement is not included since the emergency generator will only operate a maximum of 300 hours in any year	
Indirect Operating Costs	
a. Overhead (60% of OL+ML)	$288
b. Property Tax: (TCC*0.01)	$1,493
c. Insurance: (TCC*0.01)	$1,493
d. Administration: (TCC*0.02)	$2,986
Total Indirect Operating Cost	**$6,260**
Total Annual Cost	**$31,318**
PM Reduction (tons/yr)	**0.05**
Cost of Control ($/ton - PM)	**$614,080**

There are no energy or environmental issues with a Tier 2 generator that would indicate selection of a DPF as BACT, given the unfavorable economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for $PM/PM_{10}/PM_{2.5}$ for the emergency generator, Table 4-10 indicates that compliance with Subpart IIII is the most common limit. There are two BACT determinations for PA projects (Moxie projects) that both have very low $PM/PM_{10}/PM_{2.5}$ limits of 0.02 gram/hp-hr. Footprint suspects that this limit is a mistaken entry for the Subpart IIII value of 0.2 grams/kWhr. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output. Brockton (MA) also has a very low PM limit, much lower than the Subpart IIII requirements. Footprint does not consider a PM limit less than the Subpart IIII requirements to be an appropriate BACT

Overall, with the elimination of a DPF on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

4.3.4 H_2SO_4

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of ULSD as the BACT fuel, this is the lowest sulfur content fuel suitable for the emergency generator.

The BACT process for H_2SO_4 proceeds directly to the selection of BACT. Footprint has based the H_2SO_4 limit on 5% molar conversion of fuel sulfur to H_2SO_4. Most of the emergency generators in Table 4-10 do not have an H_2SO_4 limit. The only numerical limits for H_2SO_4 identified for an emergency generator are those for the two recent Ohio PSD permits (Oregon and Carroll County). The limit in each case is 0.000132 grams/kWhr. Both these project are approved with ULSD as the emergency generator fuel. Conversion of the Footprint limit to grams/kWhr indicates that 5% molar conversion of the fuel sulfur to H_2SO_4 yields 0.0005 grams/kWhr, or about 4 times the Ohio limits. Review of the Ohio approvals indicates this factor is based on an EPA toxics emission factor which apparently allows for a much lower molar conversion of fuel sulfur to H_2SO_4. While this factor may be suitable for estimating actual emissions, Footprint believes this factor is not appropriate for setting an emission limit. Therefore, given that most agencies do not even regulate emergency generator H_2SO_4, Footprint believes the PSD BACT emission rate based on 5% molar conversion of fuel sulfur to H_2SO_4 is justified as BACT. This 5% molar conversion of fuel sulfur to H_2SO_4 is a reasonable upper limit permit limit assumption for fuel combustion sources that do not have an SCR or oxidation catalyst.

4.3.5 GHG

For GHG, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion controls suitable for GHG. The BACT process for GHG proceeds directly to the selection of BACT. Given that emergency generators operate so little, agencies have not required review of generator efficiency as part of GHG BACT.

With respect to GHG, most of the emergency generators listed on the RBLC with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. Therefore, these GHG equipment-specific limits are not automatically transferrable as comparable limits for this Project. One unit listed in

Table 4-10 has a lb/MMBtu limit based on ULSD corresponding to 163.6 lb CO_2e/MMBtu. For its proposed GHG limit for the emergency generator, the Project has chosen a value based on the USEPA Part 75 default emission factors (162.85 lb/MMBtu), incorporating both CO_2, CH_4, and N_2O. The Applicant proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (162.85 lb/MMBtu) as most appropriate PSD BACT limit.

4.4 Emergency Fire Pump

This section supplements the PSD BACT analysis for the emergency diesel fire pump to address public comments made on the draft permit documents. The Project is subject to PSD review for NO_x, $PM/PM_{10}/PM_{2.5}$, H_2SO_4, and GHG, and thus the emergency diesel fire pump is subject to PSD BACT for these pollutants.

The Project includes a 371 hp emergency diesel fire pump that will have ultra-low sulfur diesel (ULSD) as the only fuel of use. Table 4-13 presents the proposed BACT limits for the emergency diesel fire pump for pollutants subject to PSD review.

Table 4-13. Emergency Diesel Fire Pump Proposed PSD BACT Limits

Pollutant	Emission Limitation (grams/kWhr)	Emission Limitation (grams/hphr)
NOx	4.0	3.0
$PM/PM_{10}/PM_{2.5}$	0.20	0.15
H_2SO_4	0.0003 lb/hr (0.00012 lb/MMBtu)	
GHG as CO2e	162.85 lb/MMBtu	

The proposed PSD BACT limits for NO_x and $PM/PM_{10}/PM_{2.5}$ are based on compliance with the EPA New Source Performance Standards (NSPS), 40 CFR 60 Subpart IIII. For a 371 hp fire pump engine, Subpart IIII requires what is referred to as a Tier 3 engine. For H_2SO_4, the PSD BACT limit is based on use of ultra-low sulfur diesel (ULSD) fuel, and conversion of 5% of the fuel sulfur on a molar basis to H_2SO_4. The GHG limit is based on EPA emission factors for ULSD.

In order to inform the PSD BACT process, Footprint has compiled all the PSD BACT determinations in the last five years for emergency fire pumps at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 4-14 provides this compilation. Review of Table 4-14 indicates that all emergency fire pumps are fired with ULSD. All emergency fire pumps in Table 4-14 do not have any post combustion controls for PSD pollutants. Table 4-14 will be referred to in the individual pollutant discussion below.

Table 4-14. Summary of Recent PSD BACT Determinations for Reciprocating Fire Pump Engines at Large (>100MW) Gas Fired Combined-Cycle Generating Plants for NO_x, PM, H_2SO_4, GHG

Facility	Location	Permit Date	Fire Pump Engine Size	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Carroll County Energy	Washington Twp., OH	11/5/2013	400 hp	Subpart IIII		0.000132 grams/kWhr	115.75 tpy
Oregon Clean Energy	Oregon, OH	06/18/2013	300 hp	Subpart IIII		0.000132 grams/kWhr	87 tpy
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	330 hp	Subpart IIII		--	Low carbon fuel and efficient operation
Hickory Run Energy LLC	New Beaver Twp., PA	04/23/2013	450 hp	1.9 gm/hp-hr	0.15 grams/hp-hr	0.00012 grams/hp-hr	33.8 tpy
Brunswick County Power	Freeman, VA	03/12/2013	305 hp	Subpart IIII		ULSD	Low carbon fuel and efficient operation
Moxie Patriot LLC	Clinton Twp PA	01/31/2013	460 hp	2.6 grams/hp-hr	0.09 grams/hp-hr	--	--
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	(2) – 371 hp	Subpart IIII		--	172 tpy
Hess Newark Energy Center	Newark, NJ	11/01/2012	270 hp	Subpart IIII		--	--
Moxie Liberty LLC	Asylum Twp PA	10/10/2012	Size not given	2.6 grams/hp-hr	0.09 grams/hp-hr	--	--
Cricket Valley	Dover, NY	09/27/2012	460 hp	Subpart IIII		--	--
ES Joslin Power	Calhoun, TX	09/12/2012	Size not given	2.08 lb/hr	0.10 lb/hr	--	--
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	270 hp	Subpart IIII		--	--
Palmdale Hybrid Power	Palmdale, CA	10/18/2011	182 hp	Subpart IIII		--	--
Thomas C. Ferguson Power	Llano, TX	09/01/2011	617 hp	3.81 lb/hr	0.20 lb/hr	--	7,027.8 lb/hr 30 day rolling average 351.4 tpy 365 day rolling average
Entergy Nine-mile Point Unit 6	Westwego, LA	08/16/2011	350 hp	--	Subpart IIII	--	CO_2e 163.6 lb/MMBtu,

Facility	Location	Permit Date	Fire Pump Engine Size	Emission Limits[1]			
				NOx	PM/PM10/PM2.5	H2SO4	GHG
Brockton Power	Brockton MA	07/20/2011 (MA Plan Approval)	100 hp	5.45 gm/hp-hr	0.032 gm/hp-hr	--	--
Avenal Power Center	Avenal, CA	05/27/2011	288 hp	3.4 grams/hp-hr	ULSD	--	--
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	265	Subpart IIII		--	--
Dominion Warren County	Front Royal, VA	12/21/2010	2,3 MMBtu/hr	Subpart IIII		--	--
Pondera/King Power Station	Houston, TX	08/05/2010	Size not given	1.54 lb/hr	0.55 lb/hr	--	--
Victorville 2 Hybrid	Victorville, CA	03/11/2010	182 hp	Subpart IIII		--	--
Panda Sherman Power	Grayson, TX	02/03/2010	Size not given	7.75 lb/hr	0.55 lb/hr	--	--
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	Size not given	9.3 lb/hr	0.7 lb/hr	--	--

[1] Short term limits only for NOx, PM, and H2SO4. Limits obtained from agency permitting documents when not available in RBLC

4.4.1 Fuel Selection

Step 1: Identify Candidate Fuels

- Natural gas
- ULSD

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although use of natural gas would be unusual for an emergency fire pump engine.

Step 3: Rank Control Technologies by Control Effectiveness

Natural gas engines can achieve lower emissions compared to ULSD.

Step 4: Evaluate Controls

Normally, for an emergency fire pump, it is very important to have the fuel supply directly available without the possibility of a natural gas supply interruption making it impossible to operate the emergency fire pump in an emergency. The purpose of the emergency fire pump is to be able to pump water in the event of a fire. So in order to maintain this important emergency function, ULSD, which can be stored in a small tank adjacent to the emergency fire pump, is the fuel of choice.

Step 5: Select BACT

ULSD is proposed as the BACT fuel for the Project emergency fire pump.

4.4.2 NO_x

Step 1: Identify Candidate Control Technologies

- Selective Catalytic Reduction
- Low NOx engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 3 engine for 371 hp fire pump unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of SCR is unusual for an emergency fire pump.

Step 3: Rank Control Technologies by Control Effectiveness

SCR can normally achieve 90% remove of NO_x emissions, so it is more effective than the Tier 3 engine design which is based on low-NO_x engine design. However, for an emergency fire pump, if this unit is used just for short period of test and facility shutdown in an actual emergency, the ability of the SCR to control emissions will be significantly reduced since the engine/SCR takes time to warm up to achieve good NOx control.

Step 4: Evaluate Controls

Since SCR is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 4-15. The capital cost estimate for an SCR system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. The SCR has been conservatively assumed to control 90% of the potential NO_x emissions even though this is unlikely in this application. Table 4-15 indicates that the cost effectiveness of an SCR is over \$90,000 per ton of NO_x. This cost is excessive, even if the emergency fire pump runs the maximum allowable amount of 300 hours per year (unlikely) and 90% NO_x control of the full potential to emit is achieved.

There are no energy or environmental issues with a Tier 3 fire pump that would indicate selection of SCR as BACT, given the unfavorable SCR economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for NO_x for the emergency fire pump, Table 4-14 indicates that compliance with Subpart IIII is the most common limit. Several BACT determinations contain gram/kWhr or gram/hp-hr limits that approximate the Subpart IIII values but do not specifically reference Subpart IIII. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output.

With the elimination of SCR on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

4.4.3 PM/PM_{10}/$PM_{2.5}$

Step 1: Identify Candidate Control Technologies

- Active Diesel Particulate Filter (DPF)
- Low PM engine design in accordance with EPA NSPS, 40 CFR 60 Subpart IIII (Tier 3 engine for 371 hp unit)

Step 2: Eliminate Infeasible Technologies

Both these technologies are technically feasible, although application of a DPF is unusual for an emergency engine.

Step 3: Rank Control Technologies by Control Effectiveness

An active DPF can achieve up to 85% particulate removal (CARB Level 3), so it is more effective than the Tier 3 engine design which is based on low-emission engine design.

Step 4: Evaluate Controls

Since a DPF is technically feasible, an economic analysis of the cost effectiveness for emission control was conducted. This economic analysis is presented in Table 4-16. The capital cost estimate for an active system is based on information provided by Milton Cat Power Systems. The other factors are from the OAQPS Cost Control Manual. Table 4-16 indicates that the cost effectiveness of an active DPF is over \$1,000,000 per ton of PM/PM_{10}/$PM_{2.5}$. This cost is excessive, even if the emergency fire pump runs the maximum allowable amount of 300 hours per year (unlikely).

TABLE 4-15 371 HP EMERGENCY FIRE PUMP
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION -

BACT Assessment							
Control System Life:		10 years					
Interest Rate:		10.00%		Baseline NOx Emissions per 40 CFR 60 Subpart IIII (tpy)			0.37
Economic Factors from MassDEP Form BWP-AQ-BACT				SCR Control Efficiency (%)			90%
Capital Recovery Factor (CRF)		0.163					
Equipment Cost (EC)		(Factor)		**Capital Recovery**			**$22,985**
a.	SCR Capital Cost Estmate (per Milton Cat)		$85,000	Direct Operating Costs			
b.	Instrumentation (0.10A)		Included	a.	Ammonia		$477
c.	Taxes and Freight	(EC*0.05)	$4,250	b	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)		$480
				c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)		$480
Total Equipment Cost (TEC)			**$89,250**	d	Maintenance Materials = Maintenance Labor		$480
Direct Installation Costs				**Total Direct Operating Cost**			**$1,440**
a.	Foundation	(TEC*0.08)	$7,140				
b.	Erection and Handling	(TEC*0.14)	$12,495				
c.	Electrical	(TEC*0.04)	$3,570	Catalyst Replacement is not included since the emergency fire pump			
d.	Piping	(TEC*0.02)	$1,785	will only operate a maximum of 300 hours in any year			
e.	Insulation	(TEC*0.01)	$893				
f.	Painting	(TEC*0.01)	$893				
Total Direct Installation Cost			**$26,775**				
				Indirect Operating Costs			
				a.	Overhead (60% of OL+ML)		$576
Indirect Installation Costs				b.	Property Tax: (TCC*0.01)		$1,410
a.	Engineering and Supervision	(TEC*0.1)	$8,925.00	c.	Insurance: (TCC*0.01)		$1,410
b.	Construction/Field Expenses	(TEC*0.05)	$4,463	d.	Administration: (TCC*0.02)		$2,820
c.	Construction Fee	(TEC*0.1)	$8,925				
d.	Start up	(TEC*0.02)	$1,785	**Total Indirect Operating Cost**			**$6,216**
e.	Performance Test	(TEC*0.01)	$893				
Total Indirect Installation Cost			**$24,990**	**Total Annual Cost**			**$30,641**
				NOx Reduction (tons/yr)			**0.33**
Total Capital Cost (TCC)			**$141,015**	**Cost of Control ($/ton - NOx)**			**$92,502**

Note 1: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

TABLE 4-16 371 HP EMERGENCY DIESEL FIRE PUMP
ECONOMIC ANALYSIS - ACTIVE DIESEL PARTICULATE FILTER

BACT Assessment			
Control System Life:	10 years		
Interest Rate:	10.00%	Baseline PM Emissions per 40 CFR 60 Subpart IIII (tpy)	0.018
Economic Factors from MassDEP Form BWP-AQ-BACT		DPF Control Efficiency (%)	85%
Capital Recovery Factor (CRF)	0.163		

Equipment Cost (EC)		(Factor)	
a.	DPF Capital Cost Estmate		$45,000
b.	Instrumentation (0.10A)		Included
c.	Taxes and Freight	(EC*0.05)	$2,250
Total Equipment Cost (TEC)			**$47,250**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$3,780
b.	Erection and Handling	(TEC*0.14)	$6,615
c.	Electrical	(TEC*0.04)	$1,890
d.	Piping	(TEC*0.02)	$945
e.	Insulation	(TEC*0.01)	$473
f.	Painting	(TEC*0.01)	$473
Total Direct Installation Cost			**$14,175**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$4,725.00
b.	Construction/Field Expenses	(TEC*0.05)	$2,363
c.	Construction Fee	(TEC*0.1)	$4,725
d.	Start up	(TEC*0.02)	$945
e.	Performance Test	(TEC*0.01)	$473
Total Indirect Installation Cost			**$13,230**
Total Capital Cost (TCC)			**$74,655**

Capital Recovery		**$12,169**
Direct Operating Costs		
a	Operating Labor (OL):(0.25 hr/shift)($25.6/hr)	$240
b	Maintenance Labor (ML):(0.25 hr/shift)($25.6/hr)	$240
c.	Maintenance Materials = Maintenance Labor	$240
Total Direct Operating Cost		**$720**

DPF Replacement is not included since the emergency fire pump will only operate a maximum of 300 hours in any year

Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$288
b.	Property Tax: (TCC*0.01)	$747
c.	Insurance: (TCC*0.01)	$747
d.	Administration: (TCC*0.02)	$1,493
Total Indirect Operating Cost		**$3,275**
Total Annual Cost		**$16,164**
PM Reduction (tons/yr)		**0.02**
Cost of Control ($/ton - PM)		**$1,033,319**

There are no energy or environmental issues with a Tier 3 fire pump that would indicate selection of a DPF as BACT, given the unfavorable economics.

Step 5: Select BACT

With respect to the selection of a PSD BACT for $PM/PM_{10}/PM_{2.5}$ for the emergency fire pump, Table 4-14 indicates that compliance with Subpart IIII is the most common limit. There are two BACT determinations for PA project (Moxie projects) that both have very low $PM/PM_{10}/PM_{2.5}$ limits of 0.02 gram/hp-hr. Footprint suspects that this limit is a mistaken entry for the Subpart IIII value of 0.2 grams/kWhr. Several Texas projects have lb/hr limits but do not provide the engine size to determine limits per unit of output. Brockton (MA) also has a very low PM limit, much lower than the Subpart IIII requirements. Footprint does not consider a PM limit less than the Subpart IIII requirements to be an appropriate BACT

With the elimination of a DPF on economic grounds, the review of other RBLC precedents supports the selection of Subpart IIII compliance as BACT.

4.4.4 H_2SO_4

For H_2SO_4, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since the only available control for H_2SO_4 is limiting the fuel sulfur content. Based on the selection of ULSD as the BACT fuel, this is the lowest sulfur content fuel suitable for the emergency fire pump.

The BACT process for H_2SO_4 proceeds directly to the selection of BACT. Footprint has based the H_2SO_4 limit on 5% molar conversion of fuel sulfur to H_2SO_4. Most of the emergency fire pumps in Table 4-14 do not have an H_2SO_4 limit. The only numerical limits for H_2SO_4 identified for an emergency fire pump are those for the two recent Ohio PSD permits (Oregon and Carroll County), and the Hickory Run (PA) project. The limit for the Ohio cases is 0.000132 grams/kWhr, and for Hickory Run is 0.00012 grams/hp-hr (0.00016 grams/kW-hr). All these projects are approved with ULSD as the emergency fire pump fuel. Conversion of the Footprint limit to grams/kWhr indicates that 5% molar conversion of the fuel sulfur to H_2SO_4 yields 0.0005 grams/kWhr, or about 4 times the Ohio limits and three times the Hickory Run limit. Review of the Ohio approvals indicates this factor is based on an EPA toxics emission factor which apparently allows for a much lower molar conversion of fuel sulfur to H_2SO_4. While this factor may be suitable for actual emissions, Footprint believes this factor is not appropriate for setting an emission limit. Therefore, given that most agencies do not even regulate emergency fire pump H_2SO_4, Footprint believes the PSD BACT emission rate based on 5% molar conversion of fuel sulfur to H_2SO_4 is justified as BACT. As noted above for the emergency diesel generator, this 5% molar conversion of fuel sulfur to H_2SO_4 is a reasonable upper limit permit limit assumption for fuel combustion sources that do not have an SCR or oxidation catalyst.

4.4.5 GHG

For GHG, this evaluation does not identify and discuss each of the five individual steps of the "top-down" BACT process, since there are no post-combustion controls suitable for GHG. The BACT process for GHG proceeds directly to the selection of BACT. Given that emergency fire pumps operate so little, agencies have not required review of fire pump efficiency as part of GHG BACT.

With respect to GHG, most of the emergency pumps listed on the RBLC with GHG limits for PSD BACT are expressed as a mass emission value, which is a project specific number reflecting the particular size and gas throughput limits of the specific project unit. Therefore, these GHG equipment-specific limits are not automatically transferrable as comparable limits for this Project. One unit listed in Table 4-14 has a lb/MMBtu limit based on ULSD corresponding to 163.6 lb CO_2e/MMBtu. For its proposed GHG limit for the emergency pumps, the Project has chosen a value based on the USEPA Part 75 default emission factors (162.85 lb/MMBtu), incorporating both CO_2, CH_4, and N_2O. The Applicant proposes a GHG PSD BACT limit expressed in the units of lb/MMBtu (162.85 lb/MMBtu) as most appropriate PSD BACT limit.

4.5 Auxiliary Cooling Tower

This section provides a PSD BACT analysis for the auxiliary mechanical draft cooling tower. The primary function for the auxiliary cooling tower is to provide necessary equipment cooling for the gas turbine itself, which is not possible to provide using the Air Cooled Condenser (ACC) used to condense steam discharged from steam turbines. The auxiliary mechanical draft cooling tower planned for use is a 3-cell commercial scale tower, with a total circulating water flow (all 3 cells) of 13,000 gallons per minute (gpm).

In general, mechanical draft cooling towers provide cooling of the circulating water by spraying (warm) circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water may be entrained into this air flow. These droplets of circulating water contain dissolved solids. Specially designed drift eliminators are typically located above the water sprays to remove most of these droplets and return them to the fill. But a small fraction of these droplets can escape into the fan discharge into the atmosphere. These droplets then evaporate, and the particulates in these droplets are a source of particulate ($PM/PM_{10}/PM_{2.5}$) emissions. $PM/PM_{10}/PM_{2.5}$ are the only PSD pollutants emitted from the auxiliary cooling tower.

The Footprint auxiliary cooling tower is being designed to limit the drift rate to 0.001% of the circulating water flow (0.13 gpm). The design dissolved solids concentration for the circulating water is 1,500 milligrams per liter (mg/l) As documented in Appendix B of the December 2012 PSD Application, Calculation Sheet 6, the potential PM/PM_{10} emissions from the auxiliary cooling tower are 0.43 tpy, and the potential $PM_{2.5}$ emissions are 0.17 tpy.

Step 1: Identify Candidate Technologies

Particulate control technologies identified for cooling towers at new large > 100 MW combined cycle turbines are as follows:

- Air-Cooled Condensers (ACCs): This eliminates the use of circulating water for cooling and thus eliminates drift for large towers used for steam turbine condenser cooling
- High efficiency cooling tower drift eliminators.
- Reduction in the dissolved solids concentration in circulating water.

Step 2: Eliminate Infeasible Technologies

ACCs are technically feasible for steam turbine condenser cooling large combined cycle units. However, use of an ACC is not technically feasible for the auxiliary equipment cooling required for a GE Frame

7FA.05 combustion turbines since ACCs cannot achieve the degree of cooling performance required. High efficiency cooling tower drift eliminators are also technically feasible for mechanical draft cooling towers. The total dissolved solids concentration (TDS) in circulating water is a function of the makeup water TDS, which depends on the makeup water source, and the TDS at which the tower is operated. Removing TDS from the makeup water is considered technically infeasible for a small auxiliary mechanical draft cooling tower. However, the TDS in the circulating water can be decreased by increasing the amount of "blowdown" from the tower. Blowdown is a stream of wastewater continuously discharged from the tower to remove TDS from the circulating water. Increasing blowdown reduces the TDS and is technically feasible.

Step 3: Rank Control Technologies by Control Effectiveness

The ranking of the technically feasible technologies is as follows:

1. High efficiency cooling tower drift eliminators: Generally recognized to be capable of achieving a drift rate of 0.0005% of circulating water flow for large cooling tower used for power plant steam turbine condenser cooling. However, for small commercial mechanical draft cooling towers being used in this application, the standard design is for 0.001% drift.
2. Reduce the TDS in circulating water: Mechanical draft cooling towers are operated with circulating water TDS as low as 1000 milligrams/liter (mg/l).

Step 4: Evaluate Controls

Footprint has compiled all the PSD BACT determinations in the last five years for mechanical draft cooling towers at new large (> 100 MW) combustion turbine combined cycle projects. This compilation is based on the USEPA RBLC (RACT/BACT/LAER Clearinghouse). Several recent projects not included in RBLC have also been included in this compilation. Table 4-17 provides this compilation.

Review of Table 4-17 indicates that the available cooling tower BACT determinations are almost exclusively for large towers used for steam turbine condenser cooling. These towers are commonly specified for 0.0005% drift. Texas project determinations typically do not have the size of the tower indicated, and only have lb/hr emissions indicated which does not provide a meaningful comparison.

The smallest tower identified with a PM PSD BACT determination is the 12,000 gpm chiller tower at the Entergy Ninemile Point project in Louisiana. This tower in fact has drift specified at 0.001%, which agrees with our finding that small towers are designed for 0.001% drift. Therefore, it is concluded that 0.001% drift is justified as BACT for the small auxiliary mechanical draft cooling tower for Footprint. All towers identified with drift limits of 0.0005% are significantly larger than the Footprint auxiliary tower.

With respect to the circulating water total dissolved solids (TDS) concentration, for projects where this value is identified, these values range from 1000 to 6200 mg/l. Only two projects have design values < Footprint's 1500 mg/l. A collateral environmental impact of increasing the blowdown to decrease TDS is increasing consumption of water. Footprint has selected 1500 mg/l as a reasonable TDS value balance to drift emissions and water conservation.

Step 5: Select BACT

The Footprint Project will meet 0.001% drift and limit the potential PM/PM_{10} emissions from the auxiliary cooling tower to 0.43 tpy, and the potential $PM_{2.5}$ emissions to 0.17 tpy. These values are justified as BACT.

Table 4-17. Summary of Recent Cooling Tower Particulate BACT Determinations for Large (>100MW) Gas Fired Combined-Cycle Generating Plants

Facility	Location	Permit Date	Cooling Tower Description (total circulating water flow rate in gallons per minute unless otherwise specified)	BACT[1] $PM/PM_{10}/PM_{2.5}$
Renaissance Power	Carson City, MI	11/1/2013	10 cell tower	0.0005% drift
Langley Gulch Power	Payette, ID	08/14/2013	76,151 gpm	Drift Eliminators (not limit specified); 5000 mg/l
Oregon Clean Energy	Oregon, OH	06/18/2013	322,000 gpm	0.0005% drift; 2030.5 mg/l
Green Energy Partners / Stonewall	Leesburg, VA	04/30/2013	187,400 gpm	0.0005% drift; 5000 mg/l
Brunswick County Power	Freeman, VA	03/12/2013	46,000 gpm (towers for turbine inlet air chillers)	0.0005% drift; 1000 mg/l
St. Joseph Energy Center	New Carlisle, IN	12/03/2012	2 towers at 170,000 gpm each	0.0005% drift
Hess Newark Energy	Newark, NJ	11/01/2012	220,870 gpm	0.0005% drift; 4150 mg/l
Channel Energy Center, LLC	Houston, TX	10/15/2012	Size not specified	1.33 lb/hr PM_{10}
Pioneer Valley Energy Center (PVEC)	Westfield, MA	04/05/2012	Full wet cooling for 431 MW combined cycle facility – circulating flow not given	0.0005% drift
Deer Park Energy Center LLC	Deer Park, TX	09/26/2012	Cooling tower size not specified	PM –3.13 lb/hr $PM_{10}/PM_{2.5}$ 1.75lb/hr
Entergy Ninemile Point Unit 6	Westwego, LA	08/16/2011	Chiller cooling tower 12,000 gpm Unit 6 cooling tower 115,847 gpm	Chiller cooling tower 0.001% drift Unit 6 cooling tower 0.0005% drift
Brockton Power	Brockton MA	7/20/2011	92,500 gpm	0.0005% drift; 3235 mg/l
Portland Gen. Electric Carty Plant	Morrow, OR	12/29/2010	Cooling tower circulating water flow rate 85,000 gpm	0.0005% drift; 1200 mg/l
Pondera/King Power Station	Houston, TX	08/05/2010	2 towers - size not specified	1.28 lb/hr/tower
Victorville 2 Hybrid	Victorville, CA	03/11/2010	130,000 gpm	0.0005% drift; 5000 mg/l
Stark Power/Wolf Hollow	Granbury, TX	03/03/2010	Cooling tower size not specified	0.0005% drift
Russell Energy Center	Hayward, CA	02/03/2010	141,352 gpm	0.0005% drift; 6200 mg/l
Panda Sherman Power	Grayson, TX	02/03/2010	Cooling tower sizes not specified	Main tower 4.68 lb/hr PM, inlet air chiller tower 0.27 lb/hr PM Both 0.0005% drift
Lamar Power Partners II LLC	Paris, TX	06/22/2009	Cooling tower size not specified	2.4 lb/hr PM_{10}
Pattillo Branch Power LLC	Savoy, TX	06/17/2009	4 towers - size not specified	1.0 lb/hr/tower PM 0.3 lb/hr/tower PM_{10}

[1]Mass emissions (lb/hr) are only specified if comparable units across projects (% drift, total dissolved solids) are not provided.

Appendix A

Updates to Footprint Air Emissions Calculations

Updated GE performance data is provided as Attachment A-1 (3 sheets). These sheets update the performance data previously provided.

Items that have changed subsequent to the public review drafts issued by MassDEP are highlighted in yellow on all the sheets that are updates of prior sheets.

Calculation Sheet 1 presents the potential to emit (PTE) calculations for one turbine. Two operating cases are used to calculate potential emissions (PTE) are 100% load at 50 °F for baseload operation (8,040 hours/year) and 100% load at 90 °F with the duct burners and evaporative coolers on (720 hours per year). GE Case 7 is 100% load at 50 °F, with a heat input of 2,130 MMBtu/hr. GE Case 12 is 100% load at 90 °F with the duct burners and evaporative coolers on with a heat input of 2,449 MMBtu/hr. The PTE values are based on the direct calculation with the exact lb/MMBtu values shown on Sheet 1.

For CO, Sheet 1 shows the PTE based on 8,760 hours of operation, but the worst case PTE is based on separate calculations using startup and shutdown (SUSD) emissions and an assumed operating scenario. These calculations are provided on Sheet 2 for GE and reflect a higher PTE for CO compared to those in Sheet 1. Therefore, the maximum SUSD scenario value for CO PTE is used. Calculation Sheet 1 shows the revised emissions for CO for both the turbine (based on a maximum rate of 8.0 lb/hr/turbine) and the auxiliary boiler with the CO catalyst. The auxiliary boiler CO emission rate with the oxidation catalyst is 10% of the prior rate (0.035 lb/MMBtu)(0.10) = 0.0035 lb/MMBtu.

Calculation Sheet 3 in the December 21, 2012 application had been for Siemens SUSD and is now dropped. Calculation Sheets 4, 5, and 6 presented emission calculations for the emergency generator, emergency diesel fire pump, and auxiliary cooling tower respectively. These have not changed and are not repeated here.

Calculation Sheet 7 presents the updated overall summary of potential-to-emit (PTE) for the facility.

Calculation Sheets 8 and 9 are new, and are the NO_x BACT cost spreadsheets for the auxiliary boiler, supporting the values in Table 4-8.

Attachment A-1 (Sheet 1 of 3)

GE Energy 107F Series 5 Rapid Response Combined Cycle Plant - Emissions Data - Natural Gas

GE Energy Performance Data - Site Conditions

Operating Point		1	2	3	4	5	6	7	8	9	10	11	12	13
Case Description		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	50% DB firing	100% DB firing	Unfired
Ambient Temperature	°F	0	0	0	20	20	20	50	50	50	90	90	90	90
Ambient Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Relative Humidity	%	60	60	60	60	60	60	60	60	60	60	60	60	60

GE Energy Performance Data - Plant Status

HRSG Duct Burner (On/Off)		Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Unfired	Fired	Fired	Unfired
Evaporative Cooler state (On/Off)		Off	Off	Off	Off	Off	Off	Off	Off	Off	On	On	On	Off
Gas Turbine Load	%	BASE	75%	50%	BASE	75%	46%	BASE	75%	46%	BASE	PEAK	PEAK	BASE
Gas Turbines Operating		1	1	1	1	1	1	1	1	1	1	1	1	1

GE Energy Performance Data - Fuel Data

GT Heat Consumption	MMBtu/hr	2300	1850	1460	2250	1790	1360	2130	1700	1310	2040	2082	2082	1980
Duct Burner Heat Consumption	MMBtu/hr	0	0	0	0	0	0	0	0	0	0	183	367	0
Total (GT + DB)	MMBtu/hr	2300	1850	1460	2250	1790	1360	2130	1700	1310	2040	2265	2449	1980

GE Energy Performance Data - HRSG Exit Exhaust Gas Emissions

NOx	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2	2
CO	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2	2
VOC	ppmvdc	1	1	1	1	1	1	1	1	1	1	2	2	1
NH3	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2	2

NOx	lb/MMBtu	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074
CO	lb/MMBtu	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045
VOC	lb/MMBtu	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0022	0.0022	0.0013
NH3	lb/MMBtu	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
Particulates - Filterable + Condensible, Including Sulfates	lb/MMBtu	0.0038	0.0048	0.0060	0.0039	0.0049	0.0065	0.0041	0.0052	0.0067	0.0043	0.0057	0.0053	0.0044

NOx	lb/hr	17.0	13.7	10.8	16.7	13.2	10.1	15.8	12.6	9.7	15.1	16.8	18.1	14.7
CO	lb/hr	8.0	8.0	6.6	8.0	8.0	6.1	8.0	7.7	5.9	8.0	8.0	8.0	8.0
VOC	lb/hr	3.0	2.4	1.9	2.9	2.3	1.8	2.8	2.2	1.7	2.7	5.0	5.4	2.6
NH3	lb/hr	6.2	5.0	3.9	6.1	4.8	3.7	5.8	4.6	3.5	5.5	6.1	6.6	5.3
Particulates - Filterable + Condensible, Including Sulfates	lb/hr	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	13.0	13.0	8.8

ppmvdc is parts per million by volume, dry basis, corrected to 15% O2
MMBtu is on a Higher Heating Value (HHV) basis

Attachment A-1 (Sheet 2 of 3)

GE Energy 107F Series 5 Rapid Response Combined Cycle Plant - Emission Data - Natural Gas

GE Energy Performance Data - Site Conditions

Operating Point		14	15	16	17	18	19	20	21	22	23	24	25
Case Description		50% DB firing	100% DB firing	Unfired	Unfired	Unfired	50% DB firing	100% DB firing	Unfired	50% DB firing	100% DB firing	Unfired	Unfired
Ambient Temperature	°F	90	90	90	90	105	105	105	105	105	105	105	105
Ambient Pressure	psia	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Ambient Relative Humidity	%	60	60	60	60	50	50	50	50	50	50	50	50

GE Energy Performance Data - Plant Status

HRSG Duct Burner (On/Off)		Fired	Fired	Unfired	Unfired	Unfired	Fired	Fired	Unfired	Fired	Fired	Unfired	Unfired
Evaporative Cooler state (On/Off)		Off	Off	Off	Off	On	On	On	Off	Off	Off	Off	Off
Gas Turbine Load	%	PEAK	PEAK	75%	47%	BASE	PEAK	PEAK	BASE	PEAK	PEAK	75%	49%
Gas Turbines Operating		1	1	1	1	1	1	1	1	1	1	1	1

GE Energy Performance Data - Fuel Data

GT Heat Consumption	MMBtu/hr	2017	2017	1590	1260	1990	2005	2005	1880	1928	1928	1520	1240
Duct Burner Heat Consumption	MMBtu/hr	183	377	0	0	0	183	377	0	183	377	0	0
Total Heat Consumption (GT + DI	MMBtu/hr	2201	2394	1590	1260	1990	2188	2382	1880	2112	2305	1520	1240

GE Energy Performance Data - HRSG Exit Exhaust Gas Emissions

NOx	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2
CO	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2
VOC	ppmvdc	1.7	1.7	1	1	1	1.7	1.7	1	1.7	1.7	1	1
NH3	ppmvdc	2	2	2	2	2	2	2	2	2	2	2	2
NOx	lb/MMBtu	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074
CO	lb/MMBtu	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045	0.0045
VOC	lb/MMBtu	0.0022	0.0022	0.0013	0.0013	0.0013	0.0022	0.0022	0.0013	0.0022	0.0022	0.0013	0.0013
NH3	lb/MMBtu	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027	0.0027
Particulates - Filterable + Condensible, Including Sulfates	lb/MMBtu	0.0059	0.0054	0.0055	0.0070	0.0044	0.0059	0.0055	0.0047	0.0062	0.0056	0.0058	0.0071

NOx	lb/hr	16.3	17.7	11.8	9.3	14.7	16.2	17.6	13.9	15.6	17.1	11.2	9.2
CO	lb/hr	8.0	8.0	7.2	5.7	8.0	8.0	8.0	8.0	8.0	8.0	6.8	5.6
VOC	lb/hr	4.8	5.3	2.1	1.6	2.6	4.8	5.2	2.4	4.6	5.1	2.0	1.6
NH3	lb/hr	5.9	6.5	4.3	3.4	5.4	5.9	6.4	5.1	5.7	6.2	4.1	3.3
Particulates - Filterable + Condensible, Including Sulfates	lb/hr	13.0	13.0	8.8	8.8	8.8	13.0	13.0	8.8	13.0	13.0	8.8	8.8

ppmvdc is parts per million by volume, dry basis, corrected to 15% O2
MMBtu is on a Higher Heating Value (HHV) basis

Attachment A-1 (Sheet 3 of 3)

GE Energy 107FA.05 Rapid Response Combined Cycle Plant
Manufacturer's Emissions Data - Natural Gas - Startup and Shutdown Conditions - Single Unit Basis

	NOx (lb)	CO (lb)	VOC (lb)	PM10 (lb)	Duration (min)
Cold Start (GT Fire to HRSG Stack Emissions Compliance with Base Load Hold)	89	285	23	7.3	45
Warm Start (GT Fire to HRSG Stack Emissions Compliance with Base Load Hold)	54	129	13	5.0	32
Hot Start (GT Fire to HRSG Stack Emissions Compliance with Base Load Hold)	28	121	12	2.6	18
Shutdown (HRSG Stack EC to GT Flame Off)	10	151	29	5.8	27

Calculation Sheet 1

Annual Potential Emissions for Combustion Turbines and Auxiliary Boiler

	One Combustion Turbine at 100% Load			Auxiliary Boiler	
	50 deg F	90 deg F	Annual	Gas	Annual
	No DF	DF, EC	tpy	lb/MMBtu	tpy
Hours per Year	8040	720		6570 (FLE)	6570 (FLE)
MMBtu/hr	2130	2449		80	
NOx (lb/MMBtu)	0.0074	0.0074	69.9	0.011	2.9
CO	8.0 lb/hr		35.0	0.0035	0.9
VOC (lb/MMBtu)	0.0013	0.0022	13.1	0.005	1.3
SO2 (lb/MMBtu)	0.0015	0.0015	14.2	0.0015	0.4
PM/PM-10/PM-2.5	8.8 lb/hr	13.0 lb/hr	40.1	0.005	1.3
NH3 (lb/MMBtu)	0.0027	0.0027	25.5	--	--
H2SO4 (lb/MMBtu)	0.001	0.001	9.4	0.0009	0.24
Lead (lb/MMBtu)	--	--	--	4.90E-07	0.00013
Formaldehyde (lb/MMBtu)	0.00035	0.00035	3.3	7.40E-05	0.019
Total HAP (lb/MMBtu)	0.000667	0.000667	6.3	1.90E-03	0.5
CO2 (lb/MMBtu)	118.9	118.9	1,122,920	118.9	31,247
CO2e (lb/MMBtu)	119.0	119.0	1,124,003	119.0	31,277

Notes:

1. DF = Duct Firing
2. EC = Evaporative Coolers
3. FLE = Full Load Equivalent
4. Annual potential emissions per turbine for all pollutants except CO and PM are based on [(2130 MMBtu/hr)(lb/MMBtu no DF)(8040 hrs)+(2449 MMBtu/hr)(lb/MMBtu DF)(720 hrs)]/2000 lb/ton
5. Annual potential emissions shown here per turbine for CO are based on 8 lb/hr for 8760 hours. However, the worst case PTE for CO includes the startup/shutdown scenario as shown in Calculation Sheet 2.
6. Annual potential emissions per turbine for PM/PM-10/PM-2.5 are based on [(8.8 lb/hr)(8040 hrs) + (13.0 lb/hr)(720 hrs)]/2000 lb/ton
7. H2SO4 emissions for the aux boiler are based on 40% molar conversion of fuel sulfur to H2SO4 Correcting for molecular weight, the H2SO4 emission rate is: (0.0015 lb SO2/MMBtu)(0.4)(98 lb/mole H2SO4)/(64 lb/mole SO2) = 0.0009 lb/MMBtu
8. Annual potential emissions for the aux boiler are based on: (80 MMBtu/hr)(lb/MMBtu)(6570 hours FLE)/(2000 lb/ton)

Calculation Sheet 2

GE Emissions for CO and VOC Including Startup Shutdown Scenario

Emissions for Normal Load Cases	MMBtu/hr	CO (lb/hr)	VOC (lb/hr)
Spring/Fall Normal Load Case 7 (50 deg)	2130	8.0	2.8
Summaer Case 13 except for 720 hours	1980	8.0	2.6
Summer Case 12 for 720 hours (90 deg)	2449	8.0	5.4
Winter Case 4 (20 deg)	2250	8.0	2.9

	ASSUMED OPERATING SCENARIOS											GE STARTUP/SHUTDOWN EMISSIONS						Normal Load Cases Emissions for Each Season	
	Assumed Operating Profile Normal Loads					starts/wk			starts/yr			CO			VOC				
	days/ week	hrs/ day	hrs/ week	Weeks/ yr	hrs/yr	cold	warm	hot	cold	warm	hot	cold	warm	hot	cold	warm	hot		
	Combined startup/shutdown pounds of emissions per single event											***436***	***280***	***272***	***52***	***42***	***41***		
												Annual SUSD emissions for each category and season (lbs)							
Spring/Fall	5	12	60	20	1200	0.25	4.75	0	5	95	0	2180	26600	0	260	3990	0		
																	Case 7	9600	3323
Summer	7	24	168	2	336	0	2	0	0	4	0	0	1120	0	0	168	0		
	5	16	80	8	640	0	5	0	0	40	0	0	11200	0	0	1680	0		
	5	12	60	2	120	0	5	0	0	10	0	0	2800	0	0	420	0		
					1096												Case 13	3008	968
																	Case 12	5760	3879
Winter	7	24	168	2	336	0	1	0	0	2	0	0	560	0	0	84	0		
	5	16	80	8	640	0.25	4.75	0	2	38	0	872	10640	0	104	1596	0		
					976												Case 4	7808	2855
TOTAL RUN HRS				42	**3272**														
Planned outage	7	24	168	4	**672**				6			2616	0	0	312	0	0		
Not Dispatched (includes time in SUSD)					**4457**														
Unplanned FO	4.1%				**359**						4			1088			164		
ANNUAL HRS					**8760**														
Total Tons in Each Category													**29.8**			**4.4**		**13.1**	**5.5**
																		CO	**VOC**
																	Total Emissions per unit	**42.9**	**9.9**

Note: The startup/shutdown cycling scenario is no longer controlling for annual VOC emissions.

Calculation Sheet 7
Summary of Facility Potential to Emit (PTE) in tons per year (tpy)

Pollutant	Annual emissions, tons/year						
	CT Unit 1 (GT + DB)	CT Unit 2 (GT + DB)	Aux Boiler	Emergency Generator	Fire Pump	Aux Cooling Tower	Facility Totals
NO_x	69.9	69.9	2.9	1.7	0.4	0	144.8
CO	42.9	42.9	0.9	1.0	0.3	0	88.0
VOC	13.1	13.1	1.3	0.35	0.12	0	28.0
SO_2	14.2	14.2	0.4	0.0017	0.0006	0	28.8
PM_{10}	40.1	40.1	1.3	0.1	0.0	0.4	82.0
$PM_{2.5}$	40.1	40.1	1.3	0.1	0.0	0.2	81.8
NH_3	25.5	25.5	0	0	0	0	51.0
H_2SO_4 mist	9.4	9.4	0.24	1.33E-04	4.84E-05	0	19.0
Lead	0	0	0.00013	8.54E-07	3.10E-07	0	0.00013
Formaldehyde	3.3	3.3	0.019	8.76E-05	4.76E-04	0	6.6
Total HAP	6.3	6.3	0.5	1.76E-03	1.57E-03	0	13.1
CO_2	1,122,920	1,122,920	31247	180	66	0	2,277,333
CO_2e	1,124,003	1,124,003	31277	181	66	0	2,279,530

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Calculation Sheet 8

80 MMBtu/hr Auxiliary Boiler
ECONOMIC ANALYSIS - SELECTIVE CATALYTIC REDUCTION

BACT Assessment				
Control System Life:	10 years			
Interest Rate:	10.00%		Baseline Emissions at 30 ppmvdc corrected to 3% O2 (tpy)	9.46
Economic Factors from MassDEP Form BWP-AQ-BACT			SCR Emissions at 3 ppmvdc corrected to 3% O2 (tpy)	0.95
Capital Recovery Factor (CRF)	0.163			

Equipment Cost (EC)		(Factor)	
a.	SCR Capital Cost Estimate (Cleaver Brooks)		$250,000
b	Taxes and Freight	(EC*0.05)	$12,500
Total Equipment Cost (TEC)			**$262,500**
Direct Installation Costs			
a.	Foundation	(TEC*0.08)	$21,000
b.	Erection and Handling	(TEC*0.14)	$36,750
c.	Electrical	(TEC*0.04)	$10,500
d.	Piping	(TEC*0.02)	$5,250
e.	Insulation	(TEC*0.01)	$2,625
f.	Painting	(TEC*0.01)	$2,625
Total Direct Installation Cost			**$78,750**
Indirect Installation Costs			
a.	Engineering and Supervision	(TEC*0.1)	$26,250
b.	Construction/Field Expenses	(TEC*0.05)	$13,125
c.	Construction Fee	(TEC*0.1)	$26,250
d.	Start up	(TEC*0.02)	$5,250
e.	Performance Test	(TEC*0.01)	$2,625
Total Indirect Installation Cost			**$73,500**
Total Capital Cost (TCC)			**$414,750**

Capital Recovery		**$67,604**
Direct Operating Costs		
a.	Ammonia	$12,261
b.	Operating Labor (OL):(0.5 hr/shift)($25.6/hr)	$10,512
c.	Maintenance Labor (ML):(0.5 hr/shift)($25.6/hr)	$10,512
d.	Maintenance Material = Maintenance Labor	$10,512
Total Direct Operating Cost		**$43,797**
Catalyst Replacement		
a.	33% of TEC required at year 3.33 and year 6.67, plus erection and indirect costs (0.25 of replacement)	
b.	10-year annualized cost for catalyst replacement	**$22,062**
Indirect Operating Costs		
a.	Overhead (60% of OL+ML)	$12,614
b.	Property Tax: (TCC*0.01)	$4,148
c.	Insurance: (TCC*0.01)	$4,148
d.	Administration: (TCC*0.02)	$8,295
Total Indirect Operating Cost		**$29,205**
Total Annual Cost		**$162,668**
NOx Reduction (tons/yr)		**8.51**
Cost of Control ($/ton - NOx)		**$19,115**

Note 1: Ammonia cost based on estimated as delivered cost for 19% aqueous ammonia of $0.60 per pound of ammonia, and 1.2 lbs of NH3 injected per pound of NOx removed

Calculation Sheet 9

80 MMBtu/hr Auxiliary Boiler
ECONOMIC ANALYSIS - ULTRA LOW NOx (ULN) BURNER COMPARED TO STANDARD LOW NOx BURNER

BACT Assessment
Control System Life: 10 years
Interest Rate: 10.00%
Economic Factors from MassDEP Form BWP-AQ-BACT
Capital Recovery Factor (CRF) 0.163

Baseline Emissions at 30 ppmvdc corrected to 3% O2 (tpy) 9.46
Controlled Emissions at 9 ppmvdc corrected to 3% O2 (tpy) 2.89

Equipment Cost (EC)		(Factor)	
a.	Capital Cost Estimate (Differential Cost of ULN compared to standard low NOx burner) (per Cleaver Brooks)		$100,000
b	Taxes and Freight	(EC*0.05)	$5,000
Total Equipment Cost (TEC)			**$105,000**

Direct Installation Costs

Direct Installation Costs are assumed to be the same for ULN compared to standard low-NOx burner

Indirect Installation Costs (based on differential cost)

a.	Engineering and Supervision	(TEC*0.1)	$10,500
b.	Construction/Field Expenses	(TEC*0.05)	$5,250
c.	Construction Fee	(TEC*0.1)	$10,500
d.	Start up	(TEC*0.02)	$2,100
e.	Performance Test	(TEC*0.01)	$1,050
Total Indirect Installation Cost			**$29,400**

Total Capital Cost Differential for ULN Compared to Standard Low NOx Burner **$134,400**

Capital Recovery **$21,907**

Direct Operating Costs

Direct Operating Costs are assumed to be the same for ULN compared to standard low-NOx burner

Indirect Operating Costs (based on differential cost)

a.	Overhead (60% of OL+ML)	$0
b.	Property Tax: (TCC*0.01)	$1,344
c.	Insurance: (TCC*0.01)	$1,344
d.	Administration: (TCC*0.02)	$2,688
Total Indirect Operating Cost		**$5,376**

Total Annual Cost	$27,283
NOx Reduction (tons/yr)	6.57
Cost of Control ($/ton - NOx)	$4,153