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April 6, 2012

State of Washington
Energy Facility Site Evaluation Council
Attention: Mr. James Luce, Chair
925 Plum Street SE, Building 4
Olympia, Washington 98504-3172

RE: Grays Harbor Energy Center
Units 3 & 4
Request to Extend the Notice of Construction and Prevention of Significant Deterioration Permit

Dear Chair Luce:

Grays Harbor Energy LLC and Grays Harbor Energy II LLC (collectively Grays Harbor Energy), the holders of the Site Certification Agreement (SCA) for the Grays Harbor Energy Center (referred to as the Project), request that the requirement to begin construction under the Notice of Construction and Prevention of Significant Deterioration (NOC/PSD) permit issued for Units 3 and 4 by the Energy Facility Site Evaluation Council (EFSEC) and the U.S. Environmental Protection Agency (EPA) be extended for an additional 18 months. The request includes the following:

- Background information, including an explanation of why the extension is needed,
- A reevaluation of Best Available Control Technology (BACT) for criteria pollutants (Attachment 1), and
- An evaluation of greenhouse gas (GHG) BACT (Attachment 2).

Background

Grays Harbor Energy proposes to add two combined-cycle combustion turbine generators (Units 3 and 4) and one steam turbine generator, in a two-on-one configuration, to the existing Units 1 and 2 at the Grays Harbor Energy Center electrical power generating facility. The addition will increase the maximum electrical generating capacity of the facility by approximately 650 megawatts electric (MWe), doubling the overall maximum generating capacity of the facility to approximately 1,300 MW. Units 3 and 4 would be located entirely within the boundary of the current SCA. As with Units 1 and 2, Units 3 and 4 would be fueled by natural gas, and no backup fuel source is proposed for electrical generation (the emergency back-up generator and fire pump are diesel fueled). The fuel for Units 3 and 4 would be supplied from the natural gas pipeline installed for the existing facility.

A permit application for the Project was submitted Grays Harbor Energy on October 30, 2009, and the final permit was signed by EPA and EFSEC. Condition 23 of the permit specifies that

the permit "shall become invalid" if construction has not commenced within 18 months after receipt of final approval. However, "EPA and EFSEC may extend the 18-month period upon satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2)." Grays Harbor Energy is submitting this extension request because it does not expect to begin construction prior to 18 months after the permit was issued.

As an independent power producer, Grays Harbor Energy does not plan to commence construction of the Project absent a long-term power purchase agreement from a major utility company. The current economic downturn has reduced the demand for new power generation in the region. As a result, Grays Harbor Energy has been unable to secure the power purchase agreements necessary to begin construction of the Project. Grays Harbor Energy is confident that market conditions will eventually improve to justify construction of Units 3 & 4.

Criteria Pollutant BACT Reevaluation

The NOC/PSD permit issued for the Units 3 & 4 was based on the criteria pollutant BACT analysis provided in the permit application submitted in October 2009 and during the ensuing permitting process. A reevaluation of BACT that considers emission limits and control alternatives applied to similar facilities permitted since the Units 3 & 4 NOC/PSD permit was issued is included as Attachment 1 to this letter.

Greenhouse Gas BACT Evaluation

On May 13, 2010, EPA promulgated the final "Tailoring Rule" with the stated intent of establishing a "common sense approach" to addressing Greenhouse Gas (GHG) emissions from stationary sources, by "tailoring" the major source applicability thresholds under the PSD and Title V air operating permit programs and providing a phased implementation for GHG permitting requirements. After January 2, 2011, the date the Tailoring Rule went into effect, new sources or modifications of existing sources expected to increase total greenhouse gas emission rates by 75,000 tons per year (tpy) or more, on a carbon dioxide equivalent (CO_2e) basis, and whose emissions exceed the PSD threshold for one or more criteria pollutants, were subject to PSD review for GHGs. Because there is no ambient standard or increment for GHGs, the only PSD requirement that applies to GHGs is that BACT must be evaluated for potential reduction of GHG emissions from the proposed project.

At the time that the NOC/PSD permit was signed, the Project was not subject to the requirements of the Tailoring Rule and thus, the permitting process did not address GHG BACT. Washington Administrative Code (WAC) 173-400-720(5)(b)(i)(B) states that a PSD permit extension request must contain "[a]n evaluation of BACT … for all pollutants subject to the approval conditions in the PSD permit." Because GHGs are not subject to any approval conditions in the permit, this permit extension request perhaps need not include a GHG BACT analysis. However, in the spirit of adhering to the EPA's Tailoring Rule and to ensure that a permit extension can be issued in a timely manner, Grays Harbor Energy is voluntarily and

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proactively providing a GHG BACT analysis. The GHG BACT analysis is included as Attachment 2 to this letter.

Conclusions

The reevaluation of BACT for criteria pollutants confirms that 1) emission limits and emission control technologies deemed BACT in the 2010 NOC/PSD permit are consistent with recent BACT determinations, and 2) no significant state-of-the-art advancement has occurred in control technologies for combustion turbine-based combined-cycle power generating facilities since the 2010 NOC/PSD permit was issued.

The BACT analysis for GHGs was developed for all equipment with the potential to emit GHGs using EPA's recommended "top-down" approach. The design for Units 3 & 4, as permitted in the 2010 NOC/PSD, currently represents the Best Available Control Technology for GHG. As appropriate, numeric GHG emission limits, output-based standards, or work practices are provided for each emission unit.

Thank you for your consideration of this permit extension request. If you have any questions, please contact Tom Metzger at 720.283.4694.

Sincerely,

Grays Harbor Energy LLC
Grays Harbor Energy II LLC

Thomas Metzger
Senior Development Manager

Enclosures

cc: Karen McGaffey, Perkins Coie
Eric Hansen, ENVIRON
Richard Biederman, Invenergy LLC
Thomas Metzger, Invenergy LLC

Combined-Cycle Combustion Turbine Project

Best Available Control Technology Analysis

Grays Harbor Energy Center,
Units 3 and 4
Satsop, Washington

Prepared for:
Grays Harbor Energy, LLC and Grays Harbor Energy II, LLC
Satsop, Washington

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
April 2012

Project Number:
29-22706D

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1 Introduction

Grays Harbor Energy, LLC and Grays Harbor Energy II LLC (collectively GHE) proposes to construct and operate two combined-cycle combustion turbine generators (Units 3 and 4), and one steam turbine generator at the existing Grays Harbor Energy Center (GHEC) electrical power generating facility. The existing natural gas pipeline system would provide fuel to the new units, which would increase the maximum electrical generating capacity of the facility by approximately 650 megawatts electric (MWe), doubling the overall maximum generating capacity of the facility to approximately 1,300 MWe.

1.1 Background

A permit application for the Project was submitted by GHE on October 30, 2009, and the final Notice of Construction and Prevention of Significant Deterioration (PSD/NOC) permit was signed by the U.S. Environmental Protection Agency (EPA) and the Energy Facility Site Evaluation Council (EFSEC). The BACT determination reflected in the PSD permit issued for the Project was based on information provided in the October 2009 permit application and during the ensuing permitting process. Condition 23 of the PSD permit specifies that the permit "shall become invalid" if construction has not commenced within 18 months after receipt of final approval. However, "EPA and EFSEC may extend the 18-month period upon satisfactory showing that an extension is justified, pursuant to 40 CFR 52.21(r)(2)." WAC 173-400-730(5)(b)(i)(B) requires that a permit extension request include a reevaluation of BACT. This document provides such a reevaluation that considers emission limits and control alternatives imposed on similar facilities that were permitted since the PSD permit was issued

1.2 Project Information

The proposed addition to the existing electric power generating facility would be comprised of the following major pieces of equipment:

- Two Power Generation Units (PGUs), each consisting of a Combustion Turbine Generator (CTG) and an associated Heat Recovery Steam Generator (HRSG) with Duct Burning capability,
- One Steam Turbine Generator (STG),
- One Ten-Cell Cooling Tower,
- One Auxiliary Boiler,
- One Diesel-Powered Back-Up Generator; and
- One Diesel-Powered Emergency Fire Pump.

Of these, only the PGUs, Auxiliary Boiler, Cooling Tower, Diesel-Powered Back-Up Generator, and Diesel-Powered Emergency Fire Pump are expected to emit air pollutants for which BACT must be evaluated.

1.3 Methodology

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was conducted. The search included all entries made after January 2007 for combined-cycle combustion turbines (CCCTs) greater than 25 MWe, auxiliary boilers, diesel-powered emergency generators and fire pumps, and cooling towers. This search was refined using the following criteria:

- Eliminating sources operated in a significantly different manner (e.g., firing fuels other than natural gas, co-firing other fuels with natural gas, simple cycle as opposed to combined cycle, and combined cycle units that do not have duct burning capability).

- Eliminating permits issued before January 2007 from the RBLC database search. A detailed search of these databases was conducted prior to the permit application in October 2009. The search was extended back to January 2007 to capture any emission units permitted, but not added to the database, prior to submittal of the permit application.

2 Power Generation Unit

The CCCTs and the duct burners associated with HRSGs that comprise the PGUs would combust pipeline natural gas exclusively. The PGUs would emit the following criteria pollutants: NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, VOCs, and sulfuric acid (H_2SO_4), as well as toxic air pollutants (TAPs). A summary of the emission limits in the permit is provided in Table 1, and a listing of similar permitted emission units found in the RBLC database is provided in Table 2.

2.1 Oxides of Nitrogen (NO_X) Emissions

In the 2010 GHEC permit, lean, premixed dry-low-NO_X (DLN) turbine burners and low-NO_X duct burners with Selective Catalytic Reduction (SCR) represented BACT for control of NO_X from CCCTs with supplemental duct firing. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 2.0 parts per million (ppm) averaged over three hours. The updated analysis indicates that SCR in combination with DLN combustion remains BACT for similar units, and that there are no more stringent permit limits (see Table 3).

2.2 Carbon Monoxide (CO) Emissions

The 2010 GHEC permit indicated that an oxidation catalyst and good combustion practices represent BACT for control of CO from CCCTs with supplemental duct firing. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 2.0 ppm, averaged over three hours. This updated BACT Analysis indicates that this technology remains BACT for similar units, and that no more stringent permit limits (see Table 4).

2.3 Sulfur Dioxide (SO_2) Emissions

The sulfur content of the fuel determines SO_2 emission rates. The sulfur content of pipeline natural gas is monitored, and, to some extent, controlled by the gas supplier. EFSEC and EPA concurred with the BACT determination for control of SO_2. Virtually all permits for CCCTs in the RBLC database indicate that use of low-sulfur fuel or pipeline quality natural gas is BACT (see Table 5), indicating that BACT for SO_2 emitted by CCCTs has not changed since permit was issued in 2010. Because the sulfur content of natural gas varies from one region to another, it is not appropriate to compare SO_2 permit limits issued to sources in different regions.

2.4 Particulate Matter (PM_{10} and $PM_{2.5}$) Emissions

Given that proper combustion is maintained, PM_{10} and $PM_{2.5}$ emissions are determined by the amounts of sulfur, nitrogen, and ash present in a fuel. While all natural gas contains negligible amounts of these constituents, the content is monitored and, to some extent, controlled by the gas supplier. The 2010 permit determined that the use of natural gas and proper combustion is BACT for PM_{10} and $PM_{2.5}$ emissions from a combined cycle gas turbine with duct firing. EFSEC and EPA concurred, and established permit limits for PM_{10} of 0.0078 lb/MMBtu with duct burners and 0.0072 lb/MMBtu without duct burning. The permit limit for $PM_{2.5}$ was established at 0.0020 lb/MMBtu with or without duct burning.

PM_{10} and $PM_{2.5}$ permit limits for similar sources vary (see Table 6), with much of the variability likely due to differences in the properties of the gas available in that region, and the turbine design. Virtually all permits in the RBLC database indicate that proper combustion of pipeline natural gas remains BACT for PM_{10} and $PM_{2.5}$.

2.5 Volatile Organic Compound (VOC) Emissions

VOC emissions are generally the result of incomplete combustion. The 2010 permit determined that DLN burners with an oxidation catalyst represent BACT for control of VOC emissions. EFSEC and EPA concurred with this BACT determination as well as the proposed permit limit of 1 ppm averaged over one hour. Virtually all permits in the RBLC database indicate that proper combustion of natural gas and an oxidation catalyst continue to be BACT (see Table 7).

2.6 Sulfuric Acid Mist (H_2SO_4) Emissions

Like SO_2 emissions, H_2SO_4 emissions are strongly related to fuel sulfur content. The 2010 permit determined that the use of natural gas and a permit limit of 3.66 lb/hr in a 12-month rolling average represented BACT. EFSEC and EPA concurred with this BACT determination. The updated review of the RBLC database indicates that the use of low-sulfur fuel or pipeline quality natural gas remains BACT for H_2SO_4 emissions from CCCTs (see Table 8).

2.7 Toxic Air Pollutant (TAP) Emissions

Analysis of BACT for toxic air pollutants (T-BACT) is required under Washington Administration Code (WAC) 173-460-040(4) for sources with a potential increase in emissions of regulated TAPs. The vast majority of TAP emissions from natural gas combustion are VOCs. For the 2010 permit, proper combustion and use of an oxidation catalyst represented T-BACT, and nothing currently in the RBLC suggests that T-BACT has changed since. Table 9 compares ammonia (NH_3) emission limits from the RBLC database with those in the GHEC permit as an example.

2.8 Summary

This BACT reevaluation demonstrates that no significant state-of-the-art advancement in BACT for CCCT-based power generating facilities has occurred. The control technologies deemed BACT in the 2010 GHEC permit are consistent with more recent BACT determinations. Where applicable, permit emission limits are also consistent with recent BACT determinations.

3 Auxiliary Boiler

The auxiliary boiler would combust exclusively natural gas and emit the following criteria pollutants: NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, VOCs, and sulfuric acid (H_2SO_4), as well as toxic air pollutants (TAPs). The auxiliary boiler generates steam to allow the steam turbine to start more quickly, which allows the facility to be responsive to changing load demands. It will operate no more than 2,500 hours per year. A summary of the auxiliary boiler emission limits in the permit is provided in Table 10, and a listing of similar permitted emission units found in the RBLC database is provided in Table 11.

3.1 NO_X Emissions

In the 2010 GHEC permit, ultra-low NO_X burners (ULNBs) represented BACT for control of NO_X from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 9.0 parts per million (ppm) averaged over one hour. The permit also limits the NO_X emissions to 0.32 lb/hr, which, when combined with the maximum heat rate (29.3 MMBtu), yields an equivalent emission factor of 0.0109 lb/MMBtu. The updated analysis indicates ULNBs remain BACT for similar units, and that the permit limit remains among the most stringent permit limits found in the RBLC database (see Table 12).

3.2 CO Emissions

The 2010 GHEC permit indicates that proper burner design and good combustion practices represents BACT for CO emissions from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 50 ppmvd. The permit also limits CO emission to 1.08 lb/hr, which, when combined with the maximum heat rate (29.3 MMBtu), yields an emission factor of 0.0369 lb/MMBtu. The updated analysis indicates no change to that determination, and that the permit limit remains among the most stringent permit limits found in the RBLC database (see Table 12).

3.3 SO_2 Emissions

Virtually all permits in the RBLC database indicate use of low-sulfur fuel (e.g., pipeline natural gas) is BACT (see Table 12). This represents no change from the BACT determination made for SO_2 emissions from the auxiliary boiler in the 2010 GHEC permit.

3.4 PM_{10} and $PM_{2.5}$ Emissions

The 2010 GHEC permit indicates that burning natural gas represents BACT for PM emissions from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 0.005 lb/MMBtu. The updated analysis indicates no change to that determination, and that the permit limit remains among the most stringent permit limits found in the RBLC database (see Table 12).

3.5 VOC Emissions

The 2010 GHEC permit indicates that proper burner design represents BACT for VOC emissions from the auxiliary boiler. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 0.004 lb/MMBtu. The updated analysis indicates that burner design and good combustion practices represent BACT for VOCs, and that the permit limit is among the most stringent permit limits found in the RBLC database (see Table 12).

3.6 TAP Emissions

As with the PGUs, the vast majority of TAP emissions from natural gas combustion are VOCs. For the 2010 permit, proper combustion represented T-BACT, and nothing currently in the RBLC suggests that T-BACT has changed since.

3.7 Summary

This BACT reevaluation demonstrates that no significant state-of-the-art advancement in BACT for natural gas-fired auxiliary boiler has occurred. The control technologies deemed BACT in the 2010 GHEC permit are consistent with more recent BACT determinations. Where applicable, permit emission limits are also consistent with recent BACT determinations.

4 Emergency Diesel Engines

A diesel-fueled back-up generator will be available to assist with an orderly shutdown of the PGU in the unusual situation that electrical power is not available from the grid during a shutdown. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection if a fire were to occur when grid power is unavailable. Under non-emergency conditions (i.e., for maintenance and testing), the engines will each operate no more than 100 hours per year. The permit requires that the engines meet the applicable standards in 40 CFR Part 60, Subpart IIII. Subpart IIII requires that an emergency generator of the size used at the site complies with an emissions limit of 2.98 g/bhp-hr for NO_x, 2.61 g/bhp-hr for CO and 0.20 g/bhp-hr for PM. Subpart IIII also requires that a firepump engine of the size used at the site complies with the emissions limits of 3.0 g/bhp-hr for NO_x and 0.15 g/bhp-hr for PM. A review of similar emission units (see Tables 13 and 14) in the RBLC database indicates that BACT has not changed since that determination was made. The engines that have a stricter permit limit are much larger than the ones that will be used at the Grays Harbor Energy site.

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5 Cooling Tower

The 2010 GHEC permit requires that drift eliminators capable of achieving a drift loss of 0.0005% or less of the recirculating water flow rate be installed, and that this, combined with a maximum 7-day average total dissolved solids (TDS) cooling water content of 1,800 ppmw, represents BACT for PM_{10} emissions from the cooling tower. EFSEC and EPA concurred with this determination as well as the suggested permit limit of 19.0 lb/day, averaged over 24 hours. The updated analysis indicates that drift eliminators continue to represent BACT (see Tables 15 and 16), and that the permit limits are still among the most stringent found in the RBLC.

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Tables

Table 1: GHEC BACT Limits for Power Generation Units

Pollutant	Averaging Period	Limit[a]
NO_X @ 15% O_2[b]	3-hour rolling average	2.0 ppm
	24-hour rolling average	1,550 lb/day
CO @ 15% O_2[c]	3-hour rolling average	2.0 ppm
SO_2	1-hour average	0.0058 lb/MMBtu
	Rolling annual average	0.0029 lb/MMBtu
PM_{10} (total w/duct firing)	1-hour average	0.0078 lb/MMBtu
PM_{10} (total w/out duct firing)	1-hour average	0.0072 lb/MMBtu
$PM_{2.5}$ (filterable)	1-hour average	0.0020 lb/MMBtu
VOC[d]	1-hour average	1.0 ppm
Sulfuric Acid Mist	12-month rolling average	3.66 lb H_2SO_4/hr
Ammonia @ 15% O_2	24-hour average	5.0 ppm
Opacity	6-minute average	5%

Notes:

a. Mass emission limits are "per turbine".

b. NOX emission limits are relieved during startup and shutdown and replaced with a limit of 175 lb/hr, averaged over the time associated with startup. NOX emissions are limited to 100 lbs per turbine per shutdown event.

c. CO emission limits are relieved during startup and shutdown and replaced with a limit of 100 lb/hr, averaged over the time associated with each startup. CO emissions are limited to 650 lbs per turbine per shutdown event.

d. VOC emission limits are relieved during startup and shutdown and replaced with a limit of 30 lb/hr, averaged over the time associated with each startup. VOC emission are limited to 40 lbs per turbine per shutdown event.

Table 2: Power Generation Unit RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Power Unit
Applied Energy LLC	San Diego, CA	3-20-09	0
Arsenal Hill Power Plant	Caddo, LA	3-20-08	2110 MMBTU/H
Athens Generating Plant	Greene, NY	1-19-07	3100 MMBTU/H
Blythe Energy Project II	Riverside, CA	4-25-07	170 MW
Caithnes Bellport Energy Center	Suffolk, NY	5-10-06	2221 MMBTU/H
Cane Island Power Park	Osceola, FL	9-8-08	1860 MMBTU/H
Carty Plant	Morrow, OR	12-29-10	2866 MMBTU/H
Chouteau Power Plant	Mayes, OK	1-23-09	1882 MMBTU/H
Fairbault Energy Park	Rice, MN	6-5-07	1758 MMBTU/H
Fpl West County Energy Center	Palm Beach, FL	1-10-07	2333 MMBTU/H
Fpl West County Energy Center Unit 3	Palm Beach County, FL	7-30-08	2333 MMBTU/H
Ineos Chocolate Bayou Facility	Brazoria, TX	8-29-06	35 MW
International Station Power Plant	Anchorage, AK	12-20-10	59900 hp ISO
King Power Station	Harris, TX	8-5-2010	1350 MW
Kleen Energy Systems, Llc	Middlesex, CT	2-25-08	2.1 MMCF/H
Langley Gulch Power Plant	Payette, ID	6-25-10	2375.28 MMBTU/H
Lawton Energy Cogen Facility	Comanche, OK	12-12-06	
Live Oaks Power Plant	Glynn, GA	4-8-10	600 MW
Madison Bell Energy Center	Madison, TX	8-18-09	275 MW
Nacogdoches Power Sterne Generating Facility	Nacogdoches, TX	6-5-06	190 MW
Natural Gas-Fired Power Generation Facility	Lamar, TX	6-22-09	250 MW
Ninemile Point Electric Generating Plant	Jefferson, LA	8-16-2011	7146 MMBTU/H
Northern States Power Co. Dba Xcel Energy - Riverside Plant	Ramsey, MN	5-16-06	1885 MMBTU/H
Otay Mesa Energy Center Llc	San Diego, CA	7-22-09	171.7 MW
Pattillo Branch Power Plant	Fannin, TX	6-17-09	350 MW
Pearsall Power Plant	Frio, TX	1-23-09	8.44 MW
Plant Mcdonough Combined Cycle	Cobb, GA	1-7-08	254 MW
Plaquemine Cogeneration Facility	Iberville, LA	7-23-08	2876 MMBTU/H
Progress Bartow Power Plant	Pinellas, FL	1-26-07	1972 MMBTU/H
Pso Southwestern Power Plt	Caddo, OK	2-9-07	
Rocky Mountain Energy Center, Llc	Weld, CO	5-2-06	300 MW

Table 2: Power Generation Unit RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Power Unit
Thomas C. Ferguson Power Plant	Llano, TX	9-1-2011	390 MW

Table 3: PGU NOx Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	SCR and DLN	BACT-PSD	2.0 ppm	3-hr avg
Other BACT Determinations				
Applied Energy LLC	SCR	BACT-PSD	2 ppm	1 hour
Athens Generating Plant	DLN, Natural gas, SCR	LAER	2 ppm	3 hour block average
Blythe Energy Project II	SCR	BACT-PSD	2 ppm	At 15% O2, 3-hr avg
Caithnes Bellport Energy Center	SCR	BACT-PSD	2ppm	
Cane Island Power Park	SCR	BACT-PSD	2 ppm	24-hr
Carty Plant	SCR	BACT-PSD	2 ppm	3-hr rolling
Chouteau Power Plant	SCR AND DLN	BACT-PSD	2 ppm	1-h avg @ 15% O2
FPL West County Energy Center	DLN and SCR	BACT-PSD	2 ppm	24-hr
FPL West County Energy Center Unit 3	DLN and SCR	BACT-PSD	2 ppm	24-hr
King Power Station	DLN burners and SCR	LAER	2 ppm	1-hour average
Langley Gulch Power Plant	SCR, DLN and Good Combustion Practices	BACT-PSD	2 ppm	3-hr rolling / 15% O2
Madison Bell Energy Center	SCR	BACT-PSD	2 ppm	@ 15% O2, 24-hr rolling average
Natural Gas-Fired Power Generation Facility	SCR	BACT-PSD	2 ppm	@ 15% O2, 24-hr rolling average
Otay Mesa Energy Center LLC	SCR	Other	2 ppm	
Pattillo Branch Power Plant	SCR	BACT-PSD	2 ppm	@ 15% O2 24-hr rolling average
Thomas C. Ferguson Power Plant	DLN and SCR	BACT-PSD	2 ppm	Rolling 24-hr at 15% Oxygen
Live Oaks Power Plant	SCR and DLN	BACT-PSD	2.5 ppm	3 hr avg
Fairbault Energy Park	DLN and SCR	BACT-PSD	3 ppm	3-hr avg
Rocky Mountain Energy Center	DLN AND SCR	BACT-PSD	3 ppm	Hourly Max
Lawton Energy Cogen Facility	SCR and DLN	BACT-PSD	3.5 ppm	@15% O2
International Station Power Plant	SCR and DLN	BACT-PSD	5 ppm	4-hr avg
PSO Southwestern Power Plant	DLN	BACT-PSD	9 ppm	
Progress Bartow Power Plant	Water Injection	BACT-PSD	15 ppm	30-day basis
Arsenal Hill Power Plant	DLN, Duct Burners and	BACT-PSD	0.007 lb/MMBtu	Max

Table 3: PGU NOx Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
	SCR			
Nacogdoches Power Sterne Generating Facility	SCR and DLN	BACT-PSD	0.070 lb/MMBtu	
Pearsall Power Plant	SCR	BACT-PSD	0.0728 lb/MMBtu	
Plaquemine Cogeneration Facility	DLN and SCR	BACT-PSD	0.083 lb/MMBtu	Hourly maximum
Ineos Chocolate Bayou Facility	DLN and SCR	BACT-PSD	0.096 lb/MMBtu	3-hr avg
Kleen Energy Systems, LLC	SCR and DLN	LAER	15.5 lb/hr	Without duct burner

Table 4: PGU CO Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Oxidation Catalyst	BACT-PSD	2.0 ppm	3-hr avg
Other BACT Determinations				
Plant McDonough Combined Cycle	Oxidation catalyst	BACT-PSD	1.8 ppm	3-hour
Caithnes Bellport Energy Center	Oxidation catalyst	BACT-PSD	2 ppm	
King Power Station	Good combustion practice, oxidation catalyst	BACT-PSD	2 ppm	3-hr rolling average
Langley Gulch Power Plant	Catalytic Oxidation and Good combustion practices	BACT-PSD	2 ppm	3-Hr Rolling / 15% O2
Live Oaks Power Plant	Good combustion practices and catalytic oxidation	BACT-PSD	2 ppm	3-hr average
Pattillo Branch Power Plant	Oxidation catalyst	BACT-PSD	2 ppm	@ 15% O2, 3-hr rolling average
Ninemile Point Electric Generating Plant	Oxidation catalyst and good combustion practices	BACT-PSD	3 ppm	hourly average
Rocky Mountain Energy Center	Oxidation catalyst and good combustion practices	BACT-PSD	3 ppm	
Thomas C. Ferguson Power Plant	Good combustion practices and oxidation catalyst	BACT-PSD	4 ppm	Rolling 3-hr at 15% oxygen
Blythe Energy Project II		BACT-PSD	4 ppm	At 15% O2, 3-hr avg
Cane Island Power Park	Good combustion practices	BACT-PSD	6 ppm	12-Month
FPL West County Energy Center Unit 3	Good combustion	BACT-PSD	6 ppm	12-Month
Progress Bartow Power Plant	Good combustion	BACT-PSD	8 ppm	24-hr block
Chouteau Power Plant	Good combustion	BACT-PSD	8 ppm	1-Hr avg
FPL West County Energy Center		BACT-PSD	8 ppm	24-Hr
Fairbault Energy Park	Good combustion	BACT-PSD	9 ppm	3-Hr avg
Northern states Power Co. DBA Xcel Energy – Riverside Plant	Good combustion practices	BACT-PSD	10 ppm	3-hr block
Natural Gas-Fired Power Generation Facility	Good Combustion Practices	BACT-PSD	15 ppm	@ 15% O2, 24-hr rolling average
Lawton Energy Cogen Facility	Good combustion practices	BACT-PSD	16.38 ppm	@15% O2
Madison Bell Energy Center	Good combustion practices	BACT-PSD	17.5 ppm	@ 15% O2, 1-hr rolling average
PSO Southwestern Power Plant	Combustion Control	BACT-PSD	25 ppm	@15% O2
Kleen Energy Systems, LLC	CO Catalyst	BACT-PSD	4.3 lb/hr	W/out Duct Burner

Table 4: PGU CO Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Arsenal Hill Power Plant	Proper operating practices	BACT-PSD	0.0679 lb/MMBtu	Max
Plaquemine Cogeneration Facility	Good combustion practices	BACT-PSD	0.0739 lb/MMBtu	Hourly maximum
Nacogdoches Power Sterne Generating Facility	Good combustion practices	BACT-PSD	0.169 lb/MMBtu	
Pearsall Power Plant	Oxidation catalyst	BACT-PSD	0.26 lb/MMBtu	
Ineos Chocolate Bayou Facility	Good combustion practices	BACT-PSD	0.560 lb/MMBtu	

Table 5: PGU SO2 Control Technologies Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Low sulfur natural gas	BACT-PSD	0.0058 lb/MMBtu	1-hr average
Other BACT Determinations				
Chouteau Power Plant	Natural gas fuel	N/A	0.0006 lb/MMBtu	3-hr average
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0011 lb/MMBtu	
Arsenal Hill Power Plant	Low sulfur natural gas	BACT-PSD	0.0057 lb/MMBtu	Max
Nacogdoches Power Sterne Generating Facility	Pipeline natural gas	BACT-PSD	0.0110 lb/MMBtu	
Plaquemine Cogeneration Facility	Low sulfur fuels	BACT-PSD	0.0142 lb/MMBtu	Hourly maximum
Thomas C. Ferguson Power Plant	Pipeline quality natural gas	BACT-PSD	0.0203 lb/MMBtu	1-hr
INEOS Chocolate Bayou Facility	Low sulfur natural gas	BACT-PSD	0.1060 lb/MMBtu	
Cane Island Power Park	Fuel specifications	BACT-PSD	2 gr S/100 SCF gas	
Progress Bartow Power Plant		BACT-PSD	2 gr S/100 SCF gas	
FPL West County Energy Center	Low sulfur fuel	BACT-PSD	2 gr S/100 SCF gas	

Table 6: PGU PM Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Low sulfur natural gas	BACT-PSD	PM_{10}: 0.0078 lb/MMBtu $PM_{2.5}$: 0.0020 lb/MMBtu	1-hr average
Other BACT Determinations for PM_{10}				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0050 lb/MMBtu	No duct burner
Lawton Energy Cogen Facility	Good combustion practices	BACT-PSD	0.0067 lb/MMBtu	
Rocky Mountain Energy Center	Natural gas and good combustion practices	BACT-PSD	0.0074 lb/MMBtu	
PSO Southwestern Power Plant	Natural gas and efficient combustion	BACT-PSD	0.0093 lb/MMBtu	
Fairbault Energy Park		BACT-PSD	0.01 lb/MMBtu	Natural gas
Blythe Energy Project II	Low sulfur natural gas	BACT-PSD	0.0103 lb/MMBtu	
Plaquemine Cogeneration Facility	Clean burning fuel	BACT-PSD	0.0116 lb/MMBtu	Hourly maximum
Nacogdoches Power Sterne Generating Facility	Pipeline natural gas	BACT-PSD	0.0415 lb/MMBtu	
INEOS Chocolate Bayou Facility	Proper combustion control and natural gas	BACT-PSD	0.0840 lb/MMBtu	
Kleen Energy Systems, LLC		BACT-PSD	11 lb/hr	No duct burner
Carty Plant	Clean fuel	BACT-PSD	2.5 lb/MMcf	
FPL West County Energy Center		BACT-PSD	2 gr S/100 scf gas	
Langley Gulch Power Plant	Good combustion practices	BACT-PSD		
Other BACT Determinations for $PM_{2.5}$				
King Power Station	Low ash fuel and good combustion practices	BACT-PSD	0.0024 lb/MMBtu	
Ninemile Point Electric Generating Plant	Low ash fuel and good combustion practices	BACT-PSD	0.0037 lb/MMBtu	1-hour average
International Station Power Plant	Good combustion practices	BACT-PSD	0.0066 lb/MMBtu	3-hour average
Thomas C. Ferguson Power Plant	Pipeline quality natural gas	BACT-PSD	0.0251 lb/MMBtu	1-hour average

Table 7: PGU VOC Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Oxidation Catalyst	BACT-PSD	1 ppm	1-hr average
Other BACT Determinations				
Chouteau Power Plant	Good combustion	LAER	0.3 ppm	3-hr avg
FPL West County Energy Center Unit 3		BACT-PSD	1.2 ppm	
Progress Bartow Power Plant	Good combustion	LAER	1.2 ppm	
Ninemile Point Electric Generating Plant	Good combustion practices	BACT-PSD	1.4 ppm	1-hr avg without duct burner
Fairbault Energy Park		BACT-PSD	1.5 ppm	
FPL West County Energy Center		BACT-PSD	1.5 ppm	
King Power Station	DLN and oxidation catalyst	BACT-PSD	1.8 ppm	3-hr rolling average
Plant McDonough Combined Cycle	Oxidation catalyst	BACT-PSD	1.8 ppm	3-hr avg
Applied Energy LLC	Oxidation Catalyst	BACT-PSD	2 ppm	1-hr avg
Langley Gulch Power Plant	Catalytic Oxidation, DLN and good combustion practices	BACT-PSD	2 ppm	3-hr rolling
Live Oaks Power Plant	Good combustion practices, catalytic oxidation	BACT-PSD	2 ppm	3-hr average
Otay Mesa Energy Center LLC		BACT-PSD	2 ppm	1 hr
Pattillo Branch Power Plant	Oxidation catalyst	Other	2 ppm	3-hr rolling avg
Thomas C. Ferguson Power Plant	Good combustion practices and oxidation catalyst	BACT-PSD	2 ppm	3-hr
Madison Bell Energy Center	Good combustion practices	BACT-PSD	2.5 ppm	1-hr rolling avg
Athens Generating Plant	Good combustion control	BACT-PSD	4 ppm	3-hr block avg
Natural Gas-Fired Power Generation Facility	Good combustion practices	BACT-PSD	4 ppm	24-hr rolling avg
Northern States Power Co. DBA Xcel Energy-Riverside Plant	Good combustion practices	BACT-PSD	4.6 ppm	3-hr block
Rocky Mountain Energy Center	Good combustion practices and oxidation catalyst	BACT-PSD	0.0029 lb/MMBtu	
Arsenal Hill Power Plant	Proper operating practices	BACT-PSD	0.0057 lb/MMBtu	Max
Nacogdoches Power Sterne Generating Facility	Good combustion practices	BACT-PSD	0.0212 lb/MMBtu	
INEOS Chocolate Bayou Facility	Proper combustion control	BACT-PSD	0.0514 lb/MMBtu	
Pearsall Power Plant	Good combustion practices and oxidation catalyst	BACT-PSD	0.8864 lb/MMBtu	
Kleen Energy Systems		LAER	10 lb/hr	Without duct burner

Table 8: PGU Sulfuric Acid Mist Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Natural gas	BACT-PSD	3.66 lb/hr 0.006 lb/MMBtu	12-month rolling average
Other BACT Determinations				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0004 lb/MMBtu	
Arsenal Hill Power Plant	Low sulfur fuel	BACT-PSD	0.0009 lb/MMBtu	Max
Nacogdoches Power Sterne Generating Facility		BACT-PSD	0.0020 lb/MMBtu	
Thomas C. Ferguson Power Plant	Pipeline quality natural gas	BACT-PSD	0.0103 lb/MMBtu	1-hour average
INEOS Chocolate Bayou Facility	Low sulfur fuel	BACT-PSD	0.0162 lb/MMBtu	

How about expressing GHE limit as lb/MMBtu?

Table 9: PGU NH3 Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project	Best management practices	T-BACT	5.0 ppm	24-hr avg
Other BACT Determinations				
Kleen Energy Systems, LLC		BACT-PSD	2 ppm	
Cane Island Power Park		BACT-PSD	5 ppm	
FPL West County Energy Center		BACT-PSD	5 ppm	
FPL West County Energy Center Unit 3		BACT-PSD	5 ppm	
Progress Bartow Power Plant			5 ppm	
Thomas C. Ferguson Power Plant	Best management practices	BACT-PSD	7 ppm	
Nacogdoches Power Sterne Generating Facility		BACT-PSD	0.0259 lb/MMBtu	
INEOS Chocolate Bayou Facility		BACT-PSD	0.0708 lb/MMBtu	

Table 10: GHEC BACT Limits for Auxiliary Boiler

Pollutant	Averaging Period	Limit
NO_X @ 15% O_2[b]	1-hour average	9 ppm
CO @ 15% O_2[c]	1-hour average	50 ppm
SO_2	1-hour average	0.0058 lb/MMBtu
	Rolling annual average	0.0029 lb/MMBtu
PM_{10} (total)	1-hour average	0.005 lb/MMBtu
$PM_{2.5}$ (filterable)	1-hour average	0.005 lb/MMBtu
VOC[d]	1-hour average	0.004 lb/MMBtu

Table 11: Auxiliary Boiler RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Emission Unit
American Municipal Power Generating Station	Meigs, OH	10-8-09	150 MMBTU/H
Caithnes Bellport Energy Center	Suffolk, NY	5-10-06	29.4 MMBTU/H
Carty Plant	Portland, OR	12-29-10	91 MMBTU/H
Chouteau Power Plant	Mayes, OK	1-23-09	33.5 MMBTU/H
Concord Steam Corporation	Merrimack, NH	2-27-09	76.7 MMBTU/H
FPL West County Energy Center	Palm Beach, FL	1-10-07	99.8 MMBTU/H
Karn Weadock Generating Complex	Bay, MI	12-29-09	220 MMBTU/H
Lawton Energy Cogen Facility	Comanche, OH	12-12-06	
Northern States Power Co. DBA Xcel Energy – Riverside Plant	Ramsey, MN	5-16-06	160 MMBTU/H
Plant McDonough Combined Cycle	Cobb, GA	1-7-08	200 MMBTU/H
Progress Bartow Power Plant	Pinellas, FL	1-26-07	99 MMBTU/H

Table 12: Auxiliary Boiler Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE (NOx)				
Grays Harbor Energy		BACT-PSD	0.0109 lb/MMBtu 9 ppm	
Other BACT Determinations (NOx)				
Caithnes Bellport Energy Center	Low NO_X burners and flue gas recirculation	BACT-PSD	0.011 lb/MMBtu	
Karn Weadock Generating Complex	Low NO_X burners	BACT-PSD	0.018 lb/MMBtu	30-day rolling average
Lawton Energy Cogen Facility	Dry low NO_X burners	BACT-PSD	0.036 lb/MMBtu	
FPL West County Energy Center		BACT-PSD	0.04 lb/MMBtu	
Concord Steam Corporation	Low NO_X burners, flue gas recirculation	LAER	0.049 lb/MMBtu	Average of 3 1-hr test runs
Carty Plant	Low NO_X burners	BACT-PSD	0.049 lb/MMBtu	
Chouteau Power Plant	Low NO_X burners	BACT-PSD	0.07 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.14 lb/MMBtu	
Current BACT Limits for GHE (CO)				
Grays Harbor Energy		BACT-PSD	0.0369 lb/MMBtu 50 ppm	
Other BACT Determinations (CO)				
Karn Weadock Generating Complex	Efficient Combustion		0.035 lb/MMBtu	Test method
Caithnes Bellport Energy Center	Good combustion practices	BACT-PSD	0.036 lb/MMBtu	
Plant McDonough Combined Cycle		BACT-PSD	0.037 lb/MMBtu	3-hr average
FPL West County Energy Center		BACT-PSD	0.08 lb/MMBtu	
Northern States Power Co. DBA Xcel Energy – Riverside Plant	Good combustion practice	BACT-PSD	0.08 lb/MMBtu	3-hr average
Progress Bartow Power Plant		BACT-PSD	0.08 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.084 lb/MMBtu	
Chouteau Power Plant	Good combustion practice		0.1499 lb/MMBtu	
Current BACT Limits for GHE (SO_2)				
Grays Harbor Energy		BACT-PSD	0.0058 lb/MMBtu 0.0029 lb/MMBtu	1-hr average Annual avg
Other BACT Determinations (SO_2)				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0005 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.0006 lb/MMBtu	

Table 12: Auxiliary Boiler Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Chouteau Power Plant	Low sulfur fuel		0.0009 lb/MMBtu	
FPL West County Energy Center		BACT-PSD	2 gr S / 100 SCF gas	
Current BACT Limits for GHE (PM_{10} and $PM_{2.5}$)				
Grays Harbor Energy		BACT-PSD	0.005 lb/MMBtu	1-hr average
Other BACT Determinations (PM_{10})				
Caithnes Bellport Energy Center	Low sulfur fuel	BACT-PSD	0.0033 lb/MMBtu	
American Municipal Power Generating Station		BACT-PSD	0.0076 lb/MMBtu	
Carty Plant	Low sulfur fuel	BACT-PSD	2.5 lb/MMcf	
FPL West County Energy Center		BACT-PSD	2 gr S / 100 SCF gas	
Current BACT Limits for GHE (VOCs)				
Grays Harbor Energy		BACT-PSD	0.004 lb/MMBtu	1-hr average
Other BACT Determinations (VOCs)				
Karn Weadock Generating Complex	Good combustion practices	BACT-PSD	0.0013 lb/MMBtu	Test Method
Chouteau Power Plant	Good combustion practices	BACT-PSD	0.0161 lb/MMBtu	
Northern States Power Co. DBA Xcel Energy – Riverside Plant	Good combustion practices	BACT-PSD	0.005 lb/MMBtu	3-hr average
Plant McDonough Combined Cycle		LAER	0.0051 lb/MMBtu	3-hr average
American Municipal Power Generating Station		BACT-PSD	0.0055 lb/MMBtu	
FPL West County Energy Center		BACT-PSD	2 gr S / 100 SCF gas	
Progress Bartow Power Plant		BACT-PSD	2 gr S / 100 SCF	

Table 13: Emergency Diesel Engine RBLC Search Results Summary

Facility and Emission Unit	Location County, State	Permit Date or Update	Output per Emission Unit
International Station Power Plant	Anchorage, AK	12-20-10	1500 KW-e
Langley Gulch Power Plant – Fire Pump	Payette, ID	6-25-10	235 KW
Langley Gulch Power Plant – Emergency Generator	Payette, ID	6-25-10	750 KW
Chouteau Power Plant – Emergency Generator	Mayes, OK	01-23-09	2200 HP
Chouteau Power Plant – Fire Pump	Mayes, OK	01-23-09	267 HP
Cane Island Power Park – Fire Pump	Osceola, FL	09-08-08	
Cane Island Power Park – Emergency Generator	Osceola, FL	09-08-08	
FPL West County Energy Center Unit 3	Palm Beach, FL	07-30-08	21 MMBtu/Hr
Arsenal Hill Power Plant	Caddo, LA	03-20-08	310 HP
Fairbault Energy Park	Rice, MN	06-05-07	1750 KW
Blythe Energy Project II	Riverside, CA	04-25-07	303 HP
Progress Bartow Energy Plant	Pinellas, FL	01-26-07	
FPL West County Energy Center – Emergency Generators	Palm Beach, FL	01-10-07	4 x 2250 KW
FPL West County Energy Center – Fire pump	Palm Beach, FL	01-10-07	
Karn Weadock Generating Complex	Bay, MI	12-29-09	2000 KW

Table 14: Emergency Diesel Engine Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE				
Grays Harbor Energy Project – Emergency Generator	Meet 40 CFR 60 Subpart IIII	BACT-PSD	NO_x: 2.98 g/bhp-hr CO: 2.61 g/bhp-hr PM: 0.15 g/bhp-hr	
Grays Harbor Energy Project – Fire Pump	Meet 40 CFR 60 Subpart IIII	BACT-PSD	NO_x: 3.0 g/bhp-hr PM: 0.15 g/bhp-hr	
Other BACT Determinations (NOx)				
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD	2.98 g/bhp-hr	NOx+NMHC
Cane Island Power Park – Fire Pump		BACT-PSD	3 g/bhp-hr	
International Station Power Plant	Turbocharger and Aftercooler	BACT-PSD	4.77 g/bhp-hr	Instantaneous
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	4.77 g/bhp-hr	NOx+NMHC
Chouteau Power Plant – Emergency Generator		BACT-PSD	4.77 g/bhp-hr	
Cane Island Power Park – Emergency Generator		BACT-PSD	4.8 g/bhp-hr	
Chouteau Power Plant – Fire Pump		BACT-PSD	5.10 lb/hr	
FPL West County Energy Center Unit 3		BACT-PSD	6.9 g/bhp-hr	
FPL West County Energy Center – Emergency Generator		BACT-PSD	6.9 g/bhp-hr	
Progress Bartow Energy Plant		BACT-PSD	7.8 g/bhp-hr	
FPL West County Energy Center – Fire pump		BACT-PSD	7.8 g/bhp-hr	
Fairbault Energy Park		BACT-PSD	10.9 g/bhp-hr	3-hr average
Blythe Energy Project II		BACT-PSD	11.23 g/bhp-hr	
Arsenal Hill Power Plant	Low sulfur fuels, limiting operating hours and maintenance	BACT-PSD	14.06 g/bhp-hr	Max
Other BACT Determinations (CO)				
Blythe Energy Project II		BACT-PSD	1.05 g/bhp-hr	
Fairbault Energy Park		BACT-PSD	2.49 g/bhp-hr	
Chouteau Power Plant – Fire Pump		BACT-PSD	2.6 g/bhp-hr	
Cane Island Power Park – Fire Pump		BACT-PSD	2.6 g/bhp-hr	
Cane Island Power Park – Emergency Generator		BACT-PSD	2.6 g/bhp-hr	
FPL West County Energy Center – Fire pump		BACT-PSD	2.6 g/bhp-hr	

Table 14: Emergency Diesel Engine Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Progress Bartow Energy Plant		BACT-PSD	2.6 g/bhp-hr	
Karn Weadock Generating Complex	Low sulfur fuel	BACT-PSD	2.61 g/bhp-hr	
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	2.61g/bhp-hr	
Chouteau Power Plant – Emergency Generator		BACT-PSD	2.61 g/bhp-hr	
Arsenal Hill Power Plant	Low sulfur fuels, limiting operating hours and maintenance	BACT-PSD	3.03 g/bhp-hr	
FPL West County Energy Center Unit 3		BACT-PSD	8 g/bhp-hr	
FPL West County Energy Center – Emergency Generator		BACT-PSD	8.5 g/bhp-hr	
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD		
Other BACT Determinations (PM)				
Karn Weadock Generating Complex	Low sulfur fuel	BACT-PSD	0.066 g/bhp-hr	
Chouteau Power Plant – Emergency Generator		BACT-PSD	0.15 g/bhp-hr	
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	0.15 g/bhp-hr	
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD	0.15 g/bhp-hr	
Fairbault Energy Park		BACT-PSD	0.318 g/bhp-hr	3-hr average
FPL West County Energy Center Unit 3 – Emergency Generator		BACT-PSD	0.4 g/bhp-hr	
Chouteau Power Plant – Fire Pump		BACT-PSD	0.41 g/bhp-hr	
Other BACT Determinations (SO_2)				
Fairbault Energy Park		BACT-PSD	0.181 g/bhp-hr	3-hr average
Chouteau Power Plant – Emergency Generator	Low sulfur diesel	BACT-PSD	0.184 g/bhp-hr	
Chouteau Power Plant – Fire Pump	Low sulfur diesel	BACT-PSD	0.187 g/bhp-hr	
Arsenal Hill Power Plant	Ultra low sulfur diesel	BACT-PSD	0.94 g/bhp-hr	Max
Cane Island Power Park – Fire Pump		BACT-PSD		
Cane Island Power Park – Emergency Generator		BACT-PSD	0.0015 % S	By weight
FPL West County Energy Center Unit 3	Ultra low sulfur diesel	BACT-PSD	0.0015 % S	
FPL West County Energy Center		BACT-PSD	0.0015 % S	

Table 14: Emergency Diesel Engine Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Other BACT Determinations (VOC)				
Fairbault Energy Park		BACT-PSD	0.318 g/bhp-hr	3-hr average
Chouteau Power Plant – Emergency Generator	Good combustion practices	BACT-PSD	0.32 g/bhp-hr	
Chouteau Power Plant – Fire Pump	Good combustion practices	BACT-PSD	1.121 g/bhp-hr	
Arsenal Hill Power Plant	Low sulfur fuel	BACT-PSD	1.127 g/bhp-hr	Max
Langley Gulch Power Plant – Emergency Generator	Tier 3 engine based good combustion practices	BACT-PSD	2.98 g/bhp-hr	NOx + NMHC
Langley Gulch Power Plant – Fire Pump	Tier 2 engine based good combustion practices	BACT-PSD	4.77 g/bhp-hr	NOx + NMHC

Table 15: Cooling Tower RBLC Search Results Summary

Facility	Location County, State	Permit Date or Update	Output per Power Unit
Langley Gulch Power Plant	Payette, ID	06-25-10	63200 gal/min
Chouteau Power Plant	Mayes, OK	01-23-09	9 cells
Plaquemine Cogeneration Facility	Iberville, LA	07-23-08	
FPL West County Energy Center	Palm Beach, FL	01-10-07	306000 gal/min
Arsenal Hill Power Plant	Caddo, LA	03-20-08	140000 gal/min
Cane Island Power Park	Osceola, FL	09-08-08	
FPL West County Energy Unit 3	Palm Beach, FL	07-30-08	
Crystal River Power Plant	Citrus, FL	10-12-07	342306 gal/min
Wolf Hollow Power Plant No. 2	Hood, TX	03-03-10	

Table 16: Cooling Tower Control Technology Search Results

Facility	Control Description	Basis	Permit Limit	Limit Notes
Current BACT Limits for GHE (PM)				
Grays Harbor Energy Project	Drift Eliminators	BACT-PSD	0.0005% drift	24-hr average
Other BACT Determinations (PM)				
Chouteau Power Plant	Drift Eliminators	BACT-PSD	3.6 lb/hr	24-hr average
Plaquemine Cogeneration Facility	Good operating practices	BACT-PSD	1.4 lb/hr	Hourly max
Arsenal Hill Power Plant	Use of mist eliminators	BACT-PSD	1.4 lb/hr	Max
FPL West County Energy Unit 3		BACT-PSD	0.0005 % Drift	
Crystal River Power Plant		BACT-PSD	0.0005 % Drift	
Wolf Hollow Power Plant No. 2	Drift eliminators	BACT-PSD	0.0005 % Drift	

Combined-Cycle Combustion Turbine Project

Greenhouse Gas Best Available Control Technology Analysis

Grays Harbor Energy Center,
Units 3 and 4
Satsop, Washington

Prepared for:
Grays Harbor Energy, LLC and Grays Harbor Energy II, LLC
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Date:
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1 Introduction

Grays Harbor Energy, LLC and Grays Harbor Energy II, LCC (collectively GHE) propose to construct and operate two combustion turbine generators (Units 3 and 4), and one steam turbine generator in a combined cycle at the existing Grays Harbor Energy Center (GHEC) electrical power generating facility. The combustion turbines would both be either GE 7FA.03 or GE 7FA.04 units. The existing natural gas pipeline system will provide fuel to the new units, which would increase the maximum electrical generating capacity of the facility by approximately 650 megawatts electric (MWe), doubling the overall maximum generating capacity of the facility to approximately 1,300 MWe.

On May 13, 2010, the U.S. Environmental Protection Agency (EPA) issued the final "Tailoring Rule" with the stated intent of establishing a "common sense approach" to addressing greenhouse gas (GHG) emissions from stationary sources, by "tailoring" the major source applicability thresholds under the Prevention of Significant Deterioration (PSD) and Title V air operating permit programs and providing a phased implementation for GHG permitting requirements. The Tailoring Rule defines GHGs as an aggregate of: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). Under the second phase of the Tailoring Rule, which began on July 1, 2011, if an existing facility with the potential to emit GHGs of 100,000 tpy CO_{2e} or more proposes a project that will result in a GHG emissions increase of 75,000 tpy CO_{2e} or more, then the project is subject to PSD review for GHGs, even if it will not significantly increase emissions of any other PSD pollutant.

Because the PSD permit was signed on December 21, 2011, before the Tailoring Rule went into effect, the project was not subject to PSD review for GHGs. It is not clear that a request to extend a permit issued prior to the effective date of the Tailoring Rule is subject to the requirements of the Tailoring Rule as a result of a permit extension request that occurs after the Tailoring Rule has gone into effect. Rather than dispute the point, GHE has conservatively assumed that the project is now subject to the requirements of the Tailoring Rule.

The existing facility is a major source of GHGs (i.e., a potential to emit greater than 100,000 tpy CO_2e), and the modification is expected to emit GHGs at a rate greater than 75,000 tpy CO_2e, thus, the Units 3 and 4 Expansion Project is subject to PSD review for GHGs. Because there are no ambient standards or increments for GHGs, the only PSD requirement that applies to GHGs is that Best Available Control Technology (BACT) must be employed to reduce GHG emissions from the proposed project.

1.1 Project Information

The proposed addition to the existing electric power generating facility would be comprised of the following major pieces of equipment:

- Two Power Generation Units (PGUs), each consisting of a Combustion Turbine Generator (CTG) and an associated Heat Recovery Steam Generator (HRSG) with Duct Burning Capability,
- One Steam Turbine Generator (STG),
- One Ten-Cell Cooling Tower,
- One Auxiliary Boiler,

- One Diesel-Powered Back-Up Generator
- One Diesel-Powered Emergency Fire Pump, and
- Five High-Voltage Circuit Breakers.

The PGU, Auxiliary Boiler, Diesel-Powered Back-Up Generator, Diesel-Powered Emergency Fire Pump, and High-Voltage Circuit Breakers are expected to emit GHGs.

1.2 BACT Analysis Process

BACT is defined at 40 CFR 52.21(b)(12) as:

> *an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air 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.*

The process for conducting BACT analyses for criteria pollutants is relatively well established because it has been implemented for decades. In contrast, BACT analyses and BACT determinations for GHGs are relatively new and few in number. This, combined with the lack of cost-effectiveness criteria for GHGs and far less available guidance, results in a much more limited “body of precedent” upon which to base GHG BACT analyses at this time. In preparing this BACT analysis, ENVIRON reviewed available information in the EPA’s RACT/BACT/LAER Clearinghouse, GHG BACT analyses and permits that include GHG limits, EPA comments on GHG BACT determinations and permit limits, guidance documents posted on EPA’s GHG permitting webpage, and other available information.

In November 2010, EPA issued guidance for conducting BACT analyses for GHGs which was updated in March 2011 (hereafter referred to as “the March 2011 Guidance”). EPA recommended (but does not require) that permitting agencies apply to GHGs the same “top down” process applied to determine criteria pollutant BACT. The top-down analysis process is comprised of the following steps:

- Step 1 – Identify Available Control Technologies. Identify all available control techniques that could potentially be applied to control emissions of the regulated pollutants from the emission units.

- Step 2 – Eliminate Technically Infeasible Alternatives. If any of the control techniques cannot be successfully used on the emission units due to technical difficulties, document this finding. Such control techniques would not be considered further in the BACT analysis.

- Step 3 – Rank Technically Feasible Alternatives. Assess the performance of each control technique and rank them beginning with the most effective control technique.

- Step 4 – Evaluate Economic, Energy, and Environmental Impacts. Estimate emission reductions, annual costs, cost effectiveness, energy impacts, and other environmental impacts of the controls techniques. Detailed cost effectiveness information is presented for the most effective control and for other control techniques that are in the least cost envelope.

- Step 5 – Select BACT. Identify the most effective option not rejected based on energy, environmental, and economic impacts.

BACT is applied on a case-by-case basis, and selection of BACT frequently requires discretion and judgment to balance competing interests. While EPA established and recommends usage of the five-step, top-down process to determine BACT, it is not a binding requirement . In this case, however, the BACT analysis presented here follows the EPA-recommended five-step, top-down process, which is applied to each individual emission unit.

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2 Project Greenhouse Gas Emissions

The project has the potential to emit four of the six gases that fall within the Tailoring Rule definition of GHGs: CO_2, CH_4, N_2O, and SF_6. The Tailoring Rule further defines CO_2e as the sum of the mass emissions of the constituent GHG, each multiplied by the appropriate global warming potential (GWP) factor provided in Table A-1 of the Federal Mandatory GHG Reporting Rule (MRR, codified in 40 CFR Part 98). Table 2-1 summarizes the calculations and shows that the project has the potential to generate a maximum of approximately 2,515,769 tons of CO_2e per year.

Table 2-1: Proposed Facility GHG Emissions

Emission Unit	Activity	Maximum Annual Operation (hr/yr)	GHG	Emission Factor[1]	Emission Rate[2]	
					(lb/hr)	(tpy)
PGU (2 Units)	4,901 MMBtu/hr	8,760	CO_2	117 lb/MMBtu	572,812	2,508,917
			CH_4	0.00220 lb/MMBtu	10.8	47.3
			N_2O	0.000220 lb/MMBtu	1.08	4.73
			CO_2e	--	573,374	2,511,377
Auxiliary Boiler	29.3 MMBtu/hr	2,500	CO_2	117 lb/MMBtu	3,425	4,281
			CH_4	0.00220 lb/MMBtu	0.0646	0.0807
			N_2O	0.000220 lb/MMBtu	0.00646	0.00807
			CO_2e	--	3,428	4,285
Back-up Generator Diesel Engine	31.9 gal/hr	100	CO_2	22.5 lb/gal	718	35.9
			CH_4	0.000913 lb/gal	0.0291	0.00146
			N_2O	0.000183 lb/gal	0.00582	0.000291
			CO_2e	--	720	36.0
Emergency Fire Pump Diesel Engine	16.5 gal/hr	100	CO_2	22.5 lb/gal	371	18.6
			CH_4	0.000913 lb/gal	0.0151	0.000753
			N_2O	0.000183 lb/gal	0.00301	0.000151
			CO_2e	--	373	18.6
Switchyard Circuit Breakers	133 lb SF_6/unit[4]	3 units	SF_6	1% leakage/year/unit[6]	0.000455	0.00200
			CO_2e		10.9	47.7
Generator Circuit Breakers	15.8 lb SF_6/unit[5]	2 units	SF_6	1% leakage/year/unit[6]	0.000036	0.00016
			CO_2e		0.9	3.8
Total	--		CO_2	--	577,326	2,513,252
			CH_4		10.9	47.4
			N_2O		1.10	4.74
			SF_6		0.000492	0.002153
			CO_2e		577,906	2,515,769

1 The emission factors for combustion of natural gas (for the PGUs and Auxiliary Boiler) and distillate fuel oil No. 2 (for the diesel engines) were obtained from 40 CFR Part 98, Tables C-1 and C-2; the lb/MMBtu and lb/gallon emission factors were calculated using the 2.2046 lb/kg conversion factor.

2 100-year time horizon global warming potential (GWP – from 40 CFR Part 98, Table A-1.

3 Emission rates for the individual GHGs were calculated by multiplying the emission factor by the maximum annual heat input or fuel use. CO_2e was calculated for each emission unit by multiplying the individual GHG emission rate by the appropriate 100-year time horizon global warming potential (GWP) factor from 40 CFR Part 98, Table A-1 (GWP factors used were: CO_2 – 1, CH_4 – 21, N_2O – 310, SF_6 – 23,900), and summing. For example, the CO_2e emission rate was calculated for the PGUs as follows:

(572,812 lb CO_2/hr * 1 lb CO_2e/lb CO_2) + (10.8 lb CH_4/hr * 21 lb CO_2e/lb CH_4) + (1.08 lb N_2O/hr * 310 lb CO_2e/lb N_2O) = 572,812 lb CO_2e/hr + 227 lb CO_2e/hr + 335 lb CO_2e/hr = 573,374 lb CO_2e/hr

4 Quantity of SF_6 in an ABB 242PMR switchyard circuit breaker.

5 Quantity of SF_6 in an ABB HGC3 generator circuit breaker.

6 Worst-case expected leakage rate, based on current industry standard.

3 Power Generation Unit

The combustion turbines and the duct burners associated with HRSGs that comprise the PGUs would combust pipeline natural gas exclusively. As indicated in the previous section, the PGUs would emit the three GHGs associated with combustion: CO_2, CH_4, and N_2O.

3.1 Step 1 – Identify Available Control Alternatives

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for the emissions unit and pollutant undergoing the BACT analysis. Available control technologies are those with a practical potential for application to the particular pollutant and emissions unit under review, which have been demonstrated in practice on full scale operations and are commercially available. Pollutant emission reduction options can be grouped into two categories:

- Inherently lower-emitting processes, practices or designs; and,
- Add-on control technologies.

Emission reduction options can sometimes be used in combination.

In the March 2011 Guidance document, EPA acknowledges that, although “clean fuels” are to be considered in step 1 of the BACT analysis, the initial list of control options does not need to include “clean fuel” options that that would fundamentally redefine the source. In this case, use of pipeline natural gas is part of the original design of the project, and is one of the, if not the, lowest-carbon fuel available. Clearly, substitution of any other fuel would drastically alter the proposed project. As a result, no electrical generation technology other than a natural gas-fired combined-cycle combustion turbine system is considered in this analysis.

3.1.1 Inherently Lower-Emitting Processes, Practices or Design

An inherently lower-emitting process is one that maximizes product yield and thermal efficiency while minimizing pollutant emissions. For electrical generation, this is typically achieved by utilizing state-of-the-art equipment design that converts as much fuel as possible to electricity, minimizes energy use, or uses clean fuels. For GHGs, clean fuels are “low-carbon” fuels or those that combust most efficiently, thereby emitting fewer GHGs per unit of heat input.

The following inherently lower-emitting processes, practices and design options are included as “available” control options for the consideration of BACT in this analysis, and all can be considered in combination. All of these control options are also considered technically feasible for the project.

- Use of lower-emitting and lower-carbon fuel; and
- Energy efficient equipment.

3.1.2 Add-On Control Technologies

In Step 1 of a top-down BACT analysis, the permit applicant and the permitting authority should consider control technologies that have a practical potential to reduce GHG emissions from the emission unit in question. EPA guidance provides that, in Step 1, permit applicants need only include control

technologies that have been demonstrated in practice on full scale operations and that are commercially available at the time the permit application is prepared.[1]

3.1.2.1 Carbon Capture and Sequestration (CCS)

The only potential add-on control technology for removing CO_2 (which constitutes greater than 99% of the GHG emissions attributable to the project) from a gas stream is typically referred to as "carbon capture and sequestration" (CCS), which consists of three stages: (1) removing or otherwise segregating CO_2 from the gas stream, (2) compressing and transporting the CO_2 to a storage facility, and (3) storing the CO_2 on a permanent or long-term basis (e.g., until a practical and economic use is identified).

Post-combustion CO_2 reduction is typically referred to as "carbon capture and sequestration or storage" (CCS), which consists of three stages: (1) removing CO_2 from the exhaust stream, (2) compressing and transporting the CO_2, and (3) permanently storing the CO_2. Technology exists for all three components of CCS, but they have not yet been deployed at a scale necessary to achieve GHG reduction targets. While components of CCS have been used commercially to produce CO_2 from coal-fired power plants, applications have been limited to capturing relatively small fractions of the CO_2 present in the exhaust to produce food and chemical grade CO_2. Scaling up of current CCS technology to capture the majority of the CO_2 produced by a power plant poses significant engineering challenges, and is not expected to become a commercial reality for over a decade.[2] Nevertheless, per the March 2011 Guidance, CCS technology is considered an available add-on control technology for reducing CO_2 emissions from fossil fuel-fired power plants.

3.1.2.2 Add-On Control Options for Non-CO_2 GHGs

Add-on technologies to remove CH_4 and N_2O exist (e.g., thermal and catalytic oxidation, non-selective catalytic reduction), but none have been employed to remove these GHG compounds from combined-cycle combustion turbines, or from combustion sources in general. Furthermore, CH_4 and N_2O emissions comprise only approximately 0.1% of the total projected GHG emissions increase; thus, application of add-on technology to reduce these pollutants would not have a practical effect on the overall GHG emission rate, even if such control were found to be technically feasible. Therefore, no add-on technologies for removal of CH_4 or N_2O will be considered in this BACT analysis.

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[1] For example, the 1990 Draft NSR Manual, states that control options should be considered "to the extent that the technologies have been successfully demonstrated in practice on full scale operations. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." The Manual further states, "Although not required in step 1, the applicant may also evaluate and propose innovative technologies as BACT. In essence, if a developing technology has the potential to achieve a more stringent emissions level than otherwise would constitute BACT or the same level at a lower cost, it may be proposed as an innovative control technology. Innovative technologies are distinguished from technology transfer BACT candidates, in that an innovative technology is still under development, and has not been demonstrated in a commercial application on identical or similar emission units."

[2] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

3.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

In Step 1, energy efficiency, use of lower-emitting fuel, and CCS were identified as potential control technologies.

3.2.1 Energy Efficiency

Maximizing the quantity of steam and electricity generated per unit of fuel combusted is the goal of most power plant designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics.

3.2.2 Use of Lower-Emitting Fuel

As discussed in Step 1, natural gas is considered to be the fossil fuel that produces the least quantity of GHGs per unit of heat input. While the combustion turbines are capable of burning other fuels, natural gas is the only fuel proposed for use in the combustion turbine and duct burners.

3.2.3 Carbon Capture and Sequestration

As stated previously, CCS consists of three stages: (1) removing CO_2 from the exhaust stream, (2) compressing and transporting the CO_2, and (3) permanently storing the CO_2.

There are three approaches to CO_2 capture that are generally applicable to power generation:

- Pre-combustion systems designed to separate CO_2 and hydrogen (H_2) from produced syngas,
- Post-combustion systems designed to separate CO_2 from flue gas, and
- Oxy-combustion that uses high-purity oxygen (O_2) instead of air, which produces flue gas composed largely of CO_2.

The first approach is really applicable to pipeline natural gas, which has had most of the CO_2 removed from the raw gas prior to being placed the pipeline for consumption. The third option, while technically feasible, is still in the development phase, and, therefore, not available commercially. Only post-combustion systems will be considered for application to the proposed PGU.

Compression and transport of CO_2 is a mature technology, and is therefore considered technically feasible.

There are four endpoints for captured CO_2: (1) geologic sequestration, (2) ocean sequestration, (3) mineral carbonation, and (4) industrial use. Some forms of geologic sequestration, such as injection into depleted oil and gas reservoirs, use in enhanced oil and gas recovery, and injection into underground saline formations are technically feasible. Others, like enhanced coal bed methane recovery, are still being developed and demonstrated. Ocean sequestration, either by injecting and dissolving CO_2 into the water column, or depositing it on the ocean floor where CO_2 is denser than water, is still in the research phase, and therefore not technically feasible. Similarly, mineral carbonation, where CO_2 is reacted with

metal oxides to form stable carbonates is in the demonstration phase, and is therefore not technically feasible. There are many mature industrial uses for CO_2, but the demand is limited, and most uses do not permanently store the CO_2, emitting it later in a product lifecycle.

In summary, there are technically feasible approaches to each of the three phases required for a CCS system; therefore, CCS is considered technically feasible for reducing CO_2 emissions from the proposed PGUs.

3.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective. Before ranking all feasible control alternatives from the previous section, the effectiveness of each is discussed.

3.3.1 Energy Efficiency

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures. The manufacturer indicates that the proposed PGUs will be capable of achieving a net efficiency of between 46 and 51 percent, and a net heat rate of between 6,665 and 7,503 British thermal units per kilowatt-hour (Btu/kWh), depending upon which generation combustion turbine is installed, the operational mode, and the ambient conditions. Operating at maximum load with duct firing, under design conditions, the net efficiency of the model 7FA.03 combustion turbine is expected to be 47 percent, and the net heat rate is expected to be 7,260 Btu/kWh. The model 7FA.04 is expected to have a 48 percent net efficiency, and an expected net heat rate of 7,115 Btu/kWh.

Maximum energy efficiency is the goal of every power generation facility, but some designs are able to achieve more efficient operation than others. Table 3-1 presents the thermal efficiencies of several recently-permitted power plants which featured natural gas-fired combined-cycle combustion turbines.

Table 3-1: Comparison of Thermal Efficiency of Recent Combined-Cycle Power Plants

Facility	Date Permit Issued (Issuing Agency)	Facility Size (MW)	Thermal Efficiency (LHV)
Grays Harbor Energy Center Units 3 & 4	12/21/2010 (EFSEC)	650	51% 7,503 Btu/kWh
Kalama Energy Center	Pending (WA Ecology)	346	57.5%
CPV Vaca Station Power Plant	Pending (Y-SAQMD)	660	55%
Palmdale Hybrid Power Project	10/18/2011 (EPA Region 9)	530/598/560	56.5%/57.3%/57.3% 7,319 Btu/kWh
Thomas C. Ferguson Power Plant	9/1/2011 (TCEQ)	590	7,730 Btu/kWh
Entergy Ninemile Point Electric Generating Plant	8/16/2011 (LDEQ)	600	7,630 Btu/kWh (HHV)
Avenal Energy Power Plant	5/27/2011 (EPA Region 9)	600	50.5%

Victorville 2 Hybrid Power Project	3/11/2010 (EPA Region 9)	563	52.7% (w/ duct burner) 59.0% (thermal solar)
Russell Energy Center	2/3/2010 (BAAQMD)	600	56.4% 7,730 Btu/kWh
Lodi Energy Center	1/22/2010 (SJVAPCD)	294	55.6%
Colusa Generation Station	10/14/2008 (EPA Region 9)	660	56%
Blythe Energy Project Phase II	4/25/2007 (EPA Region 9)	520	55 – 58%
SMUD Consumnes Phase I	9/9/2003 (CEC)	500	55.1%
Palomar Energy Project	8/8/2003 (CEC)	550	55.3% (w/o duct firing) 54.2% (w/ duct firing)

As shown in Table 3-1, the maximum efficiency of the proposed project is comparable to other recently permitted projects. Of the projects listed, only Russell Energy Center (voluntarily) and those receiving permits after January 2, 2011 (except Avenal Energy, which was grandfathered by EPA) underwent GHG BACT analyses. It should be noted that the maximum heat rate of the proposed PGUs is less than the Washington GHG Emission Performance standard (RCW 80.80), which requires that baseload electric generation facilities not emit regulated GHGs at a rate greater than 1,100 lb CO_2e/MWh (net).

3.3.2 Use of Lower-Emitting Fuel

Natural gas is the only fuel proposed for use in the combustion turbine and duct burners, and is, therefore, considered part of the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to this measure.

3.3.3 Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing the CO_2. The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas. However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by up to 40 percent. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. Experimental observations and models suggest that properly selected and maintained geological storage sites could trap over 99 percent of injected CO_2 for at least 100, and up to 1 million, years.

A CCS system would have no impact on CH_4 or N_2O in the exhaust; the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would further degrade the net GHG reduction, but because the quantities of those GHGs is so small, the degradation is slight. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 86 percent.

3.3.4 Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Carbon Capture and Sequestration – 86 percent reduction in emitted GHGs on a CO_2e basis
- Energy Efficiency – Baseline

3.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because energy efficiency and use of natural gas are considered baseline GHG control alternatives, only CCS was evaluated for economic, energy, and environmental impacts.

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the PGU flue gas, as well as to compress it for transport and storage. In the case of a combined-cycle combustion turbine, the concentration of CO_2 in the exhaust gas is dilute (i.e., between 4 and 6 percent by weight), which would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

In November 2010, the U.S. Department of Energy (DOE) National Energy Technology Laboratory published a document establishing performance and cost estimates for fossil energy plants with and without CCS systems installed. For a net 555 MWe natural gas-fired combined cycle power plant, the cost of CO_2 avoided using CCS was $95 per ton.[3] This is considerably higher than the 2013 auction reserve price set by California's GHG cap and trade rules ($10 per metric ton, or approximately $11 per short ton). It should be noted that adding the CCS system reduced the net plant efficiency by 7.4 percent, reduced the net power output by 81.5 MWe, and increased the normalized water withdrawal by 95 percent. In reality, rather than operating with a reduced net power output, the maximum design heat input would be increased to achieve a net power output equivalent to an equivalent facility without CCS, which would increase emissions of other GHGs (i.e., CH_4 and N_2O), as well as criteria and toxic air pollutants.

The considerable monetary and energy requirements of a CCS system suggest unacceptable collateral economic, energy, and environmental impacts. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the proposed PGU.

3.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the proposed PGUs is an energy-efficient system design. GHE proposes a 12-month rolling total GHG emissions limit of 2,470,034 tons of CO_2e per year (tons CO_2e/yr) for two model 7FA.03 combustion turbines, and 2,511,377 tons CO_2e/yr for two model 7FA.04 combustion turbines. In addition, GHE proposes to maintain the PGUs such that the GHG emission rate per unit of electricity produced would not exceed 878 lb CO_2e/MW on a 12-month rolling average for the model 7FA.03 combustion turbines, and 859 lb CO_2e/MW for the model 7FA.04. The mass emission limit is based on continuous operation of both

[3] National Energy Technology Laboratory. Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity. Revision 2, November 2010. DOE/NETL-2010/1397.

PGUs at 100 percent load with duct firing, and the heat rate limit is based on worst-case operation (low load and high ambient temperature).

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4 Auxiliary Boiler

The auxiliary boiler would combust exclusively natural gas and emit only the three combustion GHG gases (CO_2, CH_4, and N_2O). The auxiliary boiler generates steam to allow the steam turbine associated with the PGU to start more quickly, which allows the facility to be responsive to changing load demands. It will operate no more than 2,500 hours per year.

4.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

4.1.1 Use of Lower-Emitting Fuel

In the case of GHGs, a "clean fuel," or "low-carbon fuel" is one that generates the least amount of CO_2 when combusted. The fuel that produces the least CO_2 while allowing the operational flexibility needed to fulfill the boiler's role at the facility is natural gas. No other alternative fuels will be considered in the BACT analysis.

4.1.2 Inherently Lower-Emitting Processes, Practices or Design

Maximizing the overall efficiency of the boiler minimizes the fuel combusted per unit of steam generated, which minimizes the quantity of CO_2 generated per unit of steam. In addition, proper combustion practices and properly designed equipment can minimize non-CO_2 GHG emissions by ensuring a sufficient combustion temperature and adequate mixing of fuel with combustion air.

4.1.3 Add-On Control Technologies

As discussed in the PGU BACT analysis section, the only add-on control available to reduce CO_2 is CCS. Add-on technologies to reduce CH_4 and N_2O have not been employed to reduce GHG emissions from combustion sources, and the potential for such technologies to have a meaningful impact on overall GHG emission rates is doubtful. As for the PGUs, no add-on technologies for removal of CH_4 or N_2O will be considered as BACT for the auxiliary boiler.

4.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated. In Step 1, the use of energy efficiency and CCS were identified as potential GHG control technologies.

4.2.1 Energy Efficiency

Maximizing the quantity of steam generated per unit of fuel combusted is the goal of most boiler designers and operators. Striving for energy efficiency is technically feasible within the limitations of the second law of thermodynamics.

4.2.2 Use of Lower-Emitting Fuel

As discussed in Step 1, natural gas is considered to be the fossil fuel that produces the least quantity of GHGs per unit of heat input, and is the only fuel proposed for use in the auxiliary boiler.

4.2.3 Carbon Capture and Sequestration (CCS)

As discussed in the PGU BACT analysis, CCS systems that feature post-combustion CO_2 capture schemes are considered technically feasible for reducing CO_2 emitted by combustion units.

4.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility are ranked, starting with the most effective. The March 2011 Guidance says that "to best reflect the impact on the environment, the ranking of control options should be based on the total CO_2e rather than the total mass or mass for the individual GHGs. Before ranking all feasible control alternatives from the previous section, the effectiveness of each on a CO_2e basis is discussed.

4.3.1 Energy Efficiency

The proposed project would operate in a manner that minimizes emissions of all pollutants, and maximizes the energy derived from the fuel consumed. Thus, these measures, in combination, are considered the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to these measures.

4.3.2 Use of Lower-Emitting Fuel

Natural gas is the only fuel proposed for use in the auxiliary boiler, and is, therefore, considered part of the baseline from which all other alternatives will be evaluated, and it is assumed that all other options would be applied in addition to this measure.

4.3.3 Carbon Capture and Sequestration

A CCS system is comprised of three parts: (1) capturing the CO_2, (2) transporting the CO_2, and (3) permanently storing the CO_2. The effectiveness of the system to reduce CO_2 emissions is determined by the removal rate of CO_2 from the flue gas, and degree to which the CO_2 is retained while being transported and stored. Currently available technology can capture approximately 90 percent of the post-combustion CO_2 in flue gas. However, due to the considerable energy requirements for the capture and compression of the CO_2, the electrical generating capacity of the proposed cogeneration unit would have to be increased by up to 40 percent. Although 90 percent of the additional CO_2 generated would also be captured, the net CO_2 reduction would be reduced from 90 percent to 86 percent.

Transport of CO_2 by pipeline is a mature technology, and expected losses of CO_2 in a pipeline would be minimal. Experimental observations and models suggest that properly selected and maintained geological storage sites could trap over 99 percent of injected CO_2 for at least 100, and up to 1 million, years.

A CCS system would have no impact on CH_4 or N_2O in the exhaust; the increase in emissions of those GHG compounds as a result of the additional capacity needed to power the CCS systems would further degrade the net GHG reduction. On a CO_2e basis, CCS has the potential to reduce GHG emissions by approximately 86 percent.

4.3.4 Ranking GHG Control Alternatives by Effectiveness

Below is a ranking of the technically feasible GHG control alternatives, starting with the most effective, on a CO_2e basis:

- Carbon Capture and Sequestration – 86 percent reduction in emitted GHGs on a CO_2e basis
- Proper Combustion/Energy Efficiency – Baseline
- Lower-Emitting Fuels – Baseline

4.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because energy efficiency and use of natural gas are considered baseline GHG control alternatives, only CCS was evaluated for economic, energy, and environmental impacts.

As discussed in Step 3, CCS systems require additional energy to remove CO_2 from the boiler flue gas, as well as to compress it for transport and storage. In the case of a natural gas-fired boiler, the concentration of CO_2 in the exhaust gas is dilute (i.e., between 4 and 6 percent by weight), which would require a strong solvent to capture the CO_2, as well as a considerable amount of energy to regenerate the solvent. The economic impacts of this additional energy requirement would be in addition to the capital and operating costs associated with equipping and maintaining a CCS system.

Most cost information related to CCS technology focuses on fossil fuel (particularly coal) combustion, natural gas processing, and syngas production operations. U.S. Department of Energy analyses indicate that application of post-combustion CCS technology to a new nominal 550 MWe net output power plant would cost approximately $95 per ton of CO_2 avoided.[4] This is considerably higher than the 2013 auction reserve price set by California's GHG cap and trade rules ($10 per metric ton, or approximately $11 per short ton), even without accounting for the economy of scale realized by a 550 MWe unit as compared to that of a 29.3 MMBtu/hr unit (which could potentially generate approximately 3 MWe).

The considerable monetary and energy requirements of a CCS system suggest unacceptable economic, energy, and environmental impacts. The increased energy requirements would result in additional emissions of all pollutants other than CO_2, and, therefore, CCS systems have an unacceptable collateral environmental impact as well. As a result, CCS systems are removed from consideration as BACT for GHGs emitted by the proposed auxiliary boiler.

4.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the natural gas-fired auxiliary boiler is energy-efficient system design, and proper combustion practices. GHE proposes a rolling 12-month average GHG emissions limit of 190 pounds of CO_2e per thousand pounds of steam produced (lb/klb steam).

[4] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

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5 Reciprocating Internal Combustion Engines

A diesel-fueled back-up generator will be available to assist with an orderly shutdown of the PGUs in the unusual situation that electrical power is not available from the grid during a shutdown. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection if a fire were to occur when grid power is unavailable. The engines will each operate no more than 100 hours per 12-month rolling period for maintenance and testing.

5.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies.

The purpose of the two proposed diesel-fueled engines associated with the project is to provide quickly deployable sources of power that rely on an immediately available fuel source for use during emergency situations. The limited operation proposed for the engines under non-emergency conditions is solely intended to maintain the engines in proper working order to enable them to fulfill their emergency role should that become necessary.

Diesel engines are a well-developed technology with a long-standing reputation for reliability, and diesel fuel is a stable, easily stored source of energy. These qualities make a diesel engine the ideal candidate to supply the critical power needs of a facility when grid power is unavailable. While lower emitting processes and cleaner (i.e., lower carbon-containing) fuels undoubtedly exist, none offer the unique qualities that a diesel engine can provide for emergency power services. For this reason, no alternative processes or fuels are considered for this analysis. However, within the category of reliable diesel engines that provide sufficient power for the assigned task, use of the most efficient available model will result in the least GHG emissions.

GHG-reducing add-on technologies exist, and have been discussed at length in this document for application to a natural gas-fired combustion turbine and a natural gas-fired boiler. Because the engines must be available quickly and reliably, add-on controls that complicate operation and potentially reduce engine readiness compromise the emergency role of the engines, and are therefore unacceptable for consideration as GHG-reducing technologies for emergency diesel engines.

5.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

Use of the most efficient diesel engine that is capable of reliably providing sufficient power in timely manner is a technically feasible means of limiting GHG emissions from the emergency diesel engines.

5.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective.

The only alternative considered is the use of the most efficient diesel engines that do not compromise the availability and rapid deployment of the engines for emergency duty.

5.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because only one alternative is considered, there is no opportunity to compare and contrast the collateral impacts of competing technologies.

5.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the diesel-fueled emergency engines is the use of the most efficient engines capable of providing reliable and timely operation to fulfill the assigned emergency roles. At this evolutionary stage of the project, specific units have not yet been identified, but they will be similar in size and design to the following:

- Emergency Back-Up Generator – approximately 400 kWe, powered by an approximately 600 hp diesel-fired engine
- Emergency Firewater Pump Engine – powered by an approximately 275 hp diesel-fired engine

6 High-Voltage Circuit Breakers

The switchyard that will be installed to interconnect the PGU to the electrical transmission system (the "grid") will include high-voltage circuit breakers that will provide a means to isolate portions of the switchyard for service and to protect circuits from damage due to overload or short circuit conditions. In addition, there will be generator circuit breakers that make it possible to separate the combustion turbine generators from the main transmission system. GHE proposes to install 3 (three) 242 kV-class switchyard circuit breakers (maximum rated voltage 245 kV), and 2 (two) 7.7 kA-class generator circuit breakers (maximum rated short-circuit breaking current 63 kA) that use sulfur hexafluoride (SF_6) as a dielectric medium to insulate and quench arcing when the current is interrupted. The circuit breakers would not emit SF_6 directly, but an EPA report indicates that even closed-pressure circuit breaker designs have some leakage associated with them.[5]

6.1 Step 1 – Identify Available Control Alternatives

The first step of a top-down BACT analysis is to identify all available pollutant reduction options. Options typically fall into three categories: inherently low-emitting processes, clean fuels, and add-on control technologies. Because circuit breakers do not combust fuel of any kind, clean fuel options do not apply.

Since their introduction in the 1950s, SF_6 circuit breakers have come to dominate the market for high-voltage switchgear because they provide maximum reliability and safety while reducing the physical space and maintenance requirements of the equipment. Current state-of-the-art SF_6 circuit breakers are designed to minimize fugitive emissions to be a close to zero as possible. Industry guidelines and standards limit SF_6 leakage to 0.5 percent per year (National Electrical Manufacturers Association), or 0.1 percent per year (International Electro-technical Commission), and leakage rates for new systems are typically below 0.2 percent per year. A leak-detection program to promptly identify and eliminate fugitive emissions would further reduce the potential for SF_6 emissions.

Older, less reliable technologies with much greater space and materials requirements that utilize oil or air as the insulating and quenching media are still used at existing operations, but new breakers that use these designs are not available with the specifications required by KEC. Circuit breakers that use a vacuum as an arc-quenching media are popular for medium-voltage applications; research and development of high-voltage applications is currently underway, but high-voltage vacuum circuit breakers that do not rely on any SF_6 are not yet commercially available. Development of a replacement for SF_6 is ongoing, but none has yet been identified that can match the safety, reliability, and materials reduction capabilities provided by SF_6.

6.2 Step 2 – Eliminate Technically Infeasible Alternatives

In the second step of a top-down BACT analysis, the available pollutant reduction options listed in Step 1 are considered, and, if found to be technically infeasible for the specific emission unit under review, eliminated.

[5] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), SF6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada, June 2006, available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf.

Use of state-of-the-art SF_6 circuit breakers, with or without a leak detection and repair program, is a technically feasible approach for reducing SF_6 emissions from high-voltage circuit breakers.

Use of circuit breakers with air-, oil-, or vacuum-based designs is not technically feasible because designs of these types are not commercially available with the capacity required by the proposed project. Representatives of the three leading high-voltage circuit breaker manufacturers (ABB, Mitsubishi, and Siemens) were contacted, and each confirmed that there are no alternatives to SF_6 in the 242 kV-class of high-voltage circuit breakers, nor for the 7.7 kA-class of generator circuit breakers.

6.3 Step 3 – Rank Technically Feasible Alternatives

In Step 3, the remaining alternatives that have not been removed from consideration due to technical infeasibility, are ranked, starting with the most effective.

- State-of-the-art SF_6 circuit breakers with a leak detection and repair program
- State-of-the-art SF_6 circuit breakers

6.4 Step 4 – Evaluate Economic, Energy, and Environmental Impacts

Because the most effective alternative is proposed as BACT, an impacts analysis is not necessary. Nevertheless, while SF_6 is considered the most potent GHG, the reduction in net GHG emissions that modern circuit breaker designs are able to realize as a result of the minimization of materials and pressurization requirements afforded by the properties inherent to SF_6, more than compensates for the high GWP value.

6.5 Step 5 – Selection of BACT

Based on the analysis presented here, GHE proposes that BACT for GHGs from the high-voltage circuit breakers is the use of current state-of-the-art closed pressure SF_6 circuit breakers, operated in conjunction with a leak detection and repair program. At this evolutionary stage of the project, specific makes and models have not yet been identified, but they will be in the 242 kV class (245 kV maximum rating).