GREENHOUSE GAS BACT ANALYSIS
PUGET SOUND ENERGY
FREDONIA GENERATING STATION
EXPANSION PROJECT
MOUNT VERNON, WASHINGTON

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List of Acronyms

BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
bhp	brake-horsepower
bkW	brake-kilowatt
CARB	California Air Resources Board
CEC	California Energy Commission
CCCT	combined cycle combustion turbine
CCS	carbon capture and sequestration
CFR	code of federal regulation
CH_4	methane
CI	compression ignition
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
DC	direct current
DCS	distributed control system
DOE	United States Department of Energy
EOR	enhanced oil recovery
EPA	United States Environmental Protection Agency
EPS	emission performance standard
FGS	Fredonia Generating Station
FP&L	Florida Power and Light
FR	Federal Register
GE	General Electric
GHG	greenhouse gas
GWP	global warming potential
HHV	higher heating value
HRSG	heat recovery steam generator
kV	kilovolt
kW	kilowatt
LAER	lowest achievable emission rate
lb	pound
MSL	mean sea level
MW	megawatt
MW-hr	megawatt-hour
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standard
NETL	National Energy Technology Laboratory
NO_x	nitrogen oxides
NSPS	new source performance standard
NSR	new source review

NWCAA	Northwest Clean Air Agency
OAQPS	EPA Office of Air Quality Planning and Standards
PHPP	Palmdale Hybrid Power Project
PSD	prevention of significant deterioration
PSE	Puget Sound Energy
RBLC	RACT/BACT/LAER Clearinghouse
SCAQMD	South Coast Air Quality Management District
SCR	selective catalytic reduction
SF_6	sulfur hexafluoride
SJVAPCD	San Joaquin Valley Air Pollution Control District
tpy	tons per year
ULSD	ultra-low sulfur distillate
VAC	voltage alternating current
VDC	voltage direct current
WAC	Washington Administrative Code

This stand-alone Best Available Control Technology (BACT) analysis for greenhouse gases (GHGs) was prepared at the request of the Washington Department of Ecology (Ecology). It is provided in support of Puget Sound Energy's (PSE) Prevention of Significant Deterioration (PSD) Permit Application for the Fredonia Generating Station Expansion Project (submitted February 2011, and revised July and October 2011). This document replaces the GHG BACT analysis previously provided in Sections 5.3.4 through 5.3.4.5 and 5.4 of the PSD Permit Application. Those Application sections are now obsolete and will not be updated. GHG emission summaries in Section 3.2 and detailed emission calculations in Attachment A of the Application are up to date for all PSD pollutants including GHGs.

The following sections describe the Project (Section 2.0), summarize the Project's estimated emissions (Section 3.0), assess PSD applicability (Section 4.0), and provide a detailed BACT analysis for GHGs (Section 5.0).

2.1 PROJECT LOCATION

The Fredonia Generating Station (FGS) facility is located at 13085 Ball Road near Mount Vernon, Skagit County, Washington (see Figure 2-1). The site is on south side of Ovenell Road, south of the west end of the Skagit Regional Bayview Airport, approximately 2.5 miles inland of Padilla Bay. The proposed Project is not expected to increase the current footprint acreage of the site, which is approximately 40 acres. The terrain surrounding the facility is essentially flat. The elevation of the facility is approximately 50 feet above mean sea level (MSL). There are no known sensitive receptors nearby to the facility.

2.1.1 Land Use

The region surrounding the PSE site is primarily industrial and agricultural, with several municipal and industrial facilities in the immediate vicinity, including the Skagit Regional Bayview Airport and the Paccar Technical Center, both north of the PSE facility, and multiple lumber conversion facilities to the south.

2.2 DESCRIPTION OF THE PROPOSED SOURCE MODIFICATION

As stated in the Project's PSD Permit Application, the purpose of the proposed Project will be to provide additional power generation capacity to help meet future PSE system needs using locally available fuels. The Expansion Project must be capable of starting up and shutting down relatively quickly to meet sudden changes in system power demands. No physical change or changes in method of operation will occur to the exiting Fredonia Generating Station units. They will continue to respond to short-term system capacity requirements as they currently do.

The proposed Project involves the addition of one or two simple cycle electric generating unit(s) to the existing FGS. The Project base design will consist of one of the following high-efficiency simple cycle turbine options:

- One General Electric (GE) 7FA.05 frame turbine, approximately 207 megawatts (MW);
- One GE 7FA.04 frame turbine, approximately 181 MW;
- One Siemens SGT6-5000F4 frame turbine, approximately 197 MW; or
- Two 100 MW GE LMS100 aeroderivative turbines, totaling approximately 200 MW.

The PSD Permit Application addresses each of these options. Final turbine selection will be made on the basis of a commercial and technical evaluation by PSE after further engineering and procurement efforts, possibly after air permits are issued. The selected equipment's thermodynamic and environmental performance will meet or exceed the performance of the turbines analyzed for the PSD Permit Application.

The primary fuel for the new gas turbine unit(s) will be natural gas. Back-up ultra-low-sulfur fuel oil (ULSD) will be needed/used rarely when natural gas is not reasonably available. PSE anticipates that operation of the new combustion turbine unit(s) on ULSD will occur no more than 336 hours per year. The back-up fuel use is described further in Sections 1.1 (Introduction) and 5 (BACT) of the PSD Permit Application.

In addition to the turbine(s), the Project includes one nominal 600 kilowatt (kW) diesel standby generator (Caterpillar C18, or equivalent) to supply the new units' critical electrical loads in the event power could not be back fed from either the site's 230 kilovolt (kV) or 115 kV

transmission systems. The turbine(s) would be supplied with a 125 VDC (voltage direct current) battery bank to supply a critical 120 VAC (voltage alternating current) Essential Power Bus through an inverter or directly from a 125 VDC Essential Power Bus. Examples of devices needing Essential Power from one or both of these sources would be the facility's Distributed Control System (DCS), protective relays and a direct current (DC) driven emergency lube oil pump. In the event of a transmission system failure and blackout of the facility, the 125 VDC and 120 VAC Essential Power Buses could be kept energized for a period of time from the 125 VDC battery bank. However, the turbine units have the potential to expend the battery's power quickly since they have large, heavy components, such as rotor bearings, that need large electrically driven lubricating pumps. To prevent damage to these components during a transmission system failure, an emergency generator is needed to provide power to back up the batteries. Testing and maintenance operations for the emergency generator are expected to occur 1 hour per week, or 52 hours per year. It is estimated that emergency use will not exceed 223 hours, for a total of up to 275 hours of emergency generator operation annually.

The Project's proposed new 230 kV switchyard will include eight new circuit breakers filled with sulfur hexafluoride (SF_6), a gaseous dielectric commonly used in breakers. In addition to these eight breakers accommodating the new equipment, there will also be two other new breakers installed to replace some existing units. A small amount of the GHG pollutant SF_6 might be emitted from switchyard breakers as a result of unavoidable leakage. Therefore, these 10 breakers are included in the Project's PSD Permit Application due to their potential GHG emissions. Although specific models have not been identified, PSE expects that Mitsubishi 200-SFMT-40E or 200-SFMT-63F breakers (or similar) will be used.

Conceptual plot plans for each of the four gas turbine options are provided in Figures 2-2 through 2-4 and Attachment C-2 in the PSD Permit Application. These figures are not duplicated in this GHG BACT Analysis.

2.3 PSD APPLICABILITY

The existing facility is a PSD major source. The proposed Project is considered a major modification to the existing source, thereby triggering this PSD process. Details regarding regulatory applicability are provided in Section 4 of the PSD Permit Application, and GHG emissions provided below in Section 3.1 of this document.

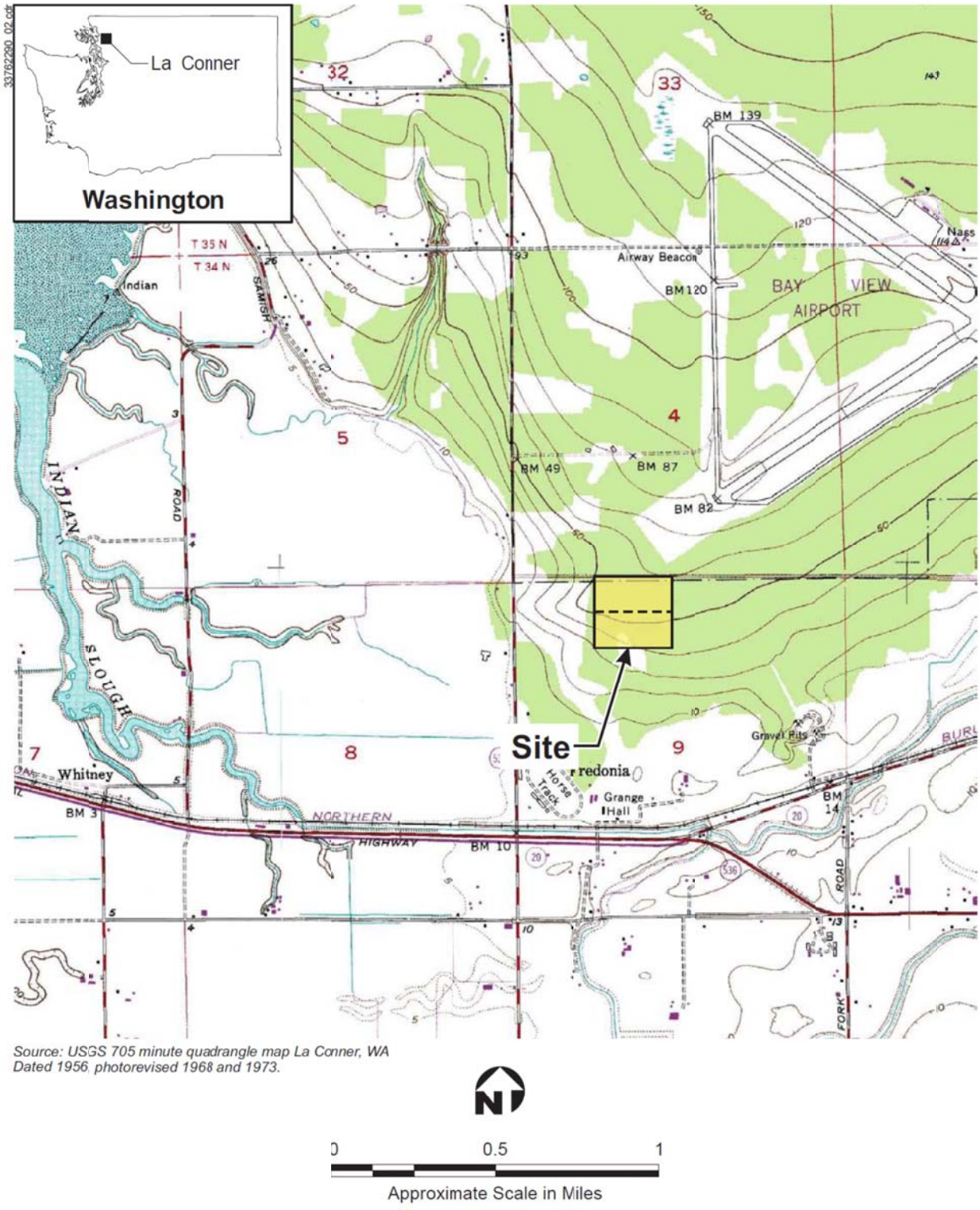

Figure 2-1 – General Location Map

3.1 ESTIMATED EMISSIONS FOR APPLICABILITY ANALYSES

This existing Fredonia Generating Station (FGS) is a major source of GHG. Emissions from existing operations at the FGS exceed 75,000 tons per year (tpy).

Potential annual emissions for the new gas turbine units and auxiliary equipment are based on worst-case operating scenarios estimated by PSE, and were generated from forecast load requirements. Maximum annual operating hours for the Frame turbines (GE 7FA.05, GE 7FA.04, and Siemens SGT6-5000F4) are expected to be approximately 2400 hours per year. Maximum annual operating hours for the GE LMS100's are expected to be approximately 3200 hours per year (for each of the two units). A maximum of 336 hours (equivalent to 14 days) firing on distillate is included in the annual emission estimates. On a pollutant-by-pollutant basis, this worst-case maximum of 336 hours (consecutive or nonconsecutive) firing on backup ULSD is included in the annual emission estimates only if pollutant emissions on ULSD are higher than emissions on natural gas.

A worst-case maximum number of start-ups and shutdowns on both natural gas and ULSD are also included in the annual emission estimates. Table 3-1 summarizes potential annual emission estimates for the four turbine options. Table 3-2 provides a breakdown of the potential individual GHG compounds from the Project: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and SF_6. The total carbon dioxide equivalents (CO_2e) for each equipment unit is also shown, calculated using the Global Warming Potential (GWP) for each individual pollutant. Detailed emission spreadsheets are included in Attachment A of the Project's revised PSD Permit Application and are not duplicated in this document.

The Project's circuit breakers will have the potential to emit a very small amount of GHG (as SF_6). Circuit breakers do not emit SF_6 normally, but do have the potential for minor leakage, or fugitive emissions. The rate of leakage is conservatively assumed to be 0.5 percent per year based on estimates from PSE for previous equipment which showed lower rates. The quantity of SF_6 in each circuit breaker is based on equipment specifications. Because specific breakers have not yet been chosen for this Project, the equipment option with the highest volume of SF_6 has been assumed for the emission calculations. Emission calculation details are provided in Attachment A-13 of the PSD Permit Application. The breaker emissions are used in the GHG analyses, applying the 100-year SF_6 GWP of 23,900 to convert SF_6 emissions to CO_2e. This conversion is also shown in Attachment A-13, and the breaker emissions are included in the CO_2e emission totals shown in in Attachment A-1 of the PSD Permit Application.

Further details regarding PSD applicability are addressed in Section 4.1 of the PSD Permit Application.

Table 3-1
Estimated Annual Emissions for the Potential Turbine Options

Pollutant	Expected Increased Emissions (tpy)				Significant Emission Rate (PSD Threshold) (tpy)
	GE 7FA.05	GE 7FA.04	Siemens SGT6-5000F4	GE LMS100 (2 Units)	
NO_x	32	31	38	37	40
CO	58	39	*160*	31	100
SO_2	7	6	6	8	40
TSP	*43*	*43*	*32*	*45*	25
PM_{10}	*43*	*43*	*32*	*45*	15
$PM_{2.5}$	*43*	*43*	*32*	*45*	10
VOC	6	5	20	8	40
H_2SO_4	*16*	*14*	*17*	*17*	7
Pb	0.0200	0.0194	0.0194	0.0193	0.6
CO_2e	*311,631*	*274,752*	*302,023*	*327,826*	75,000

(1)40 CFR 51.166(b)(48)(v)(b).

Notes:

- Emissions estimates are inclusive of the turbine(s), one emergency generator and switchyard breakers, and are based on equipment vendor data (as provided by Black & Veatch and PSE) and operating scenarios provided by PSE (see Attachment A of the Project's PSD Permit Application for details).
- SO_2 and particulate emissions are based on historic annual average sulfur content in natural gas of 2.25 grains (gr) per 100 standard cubic foot (scf) [gr/100 scf] reported at the Williams Northwest Pipeline Sumas compressor station.
- Significant Emission Rate (SER) per 40 CFR 52.21(b)(23)(i) and WAC 173-400-030. The PSD Threshold for CO_2e is from 40 CFR 51.166(b)(48)(v)(b).
- Values shown in *italic* exceed the SER.
- Gas turbine CO_2e emissions in this table are based on CO_2 emission estimates in PSD Permit Application Attachment A. For reasons cited in Section 5.3.1 of this GHG BACT Analysis, CO_2 is the predominant contributor to total CO_2e emissions; emissions of other GHGs (including N_20, CH_4, and SF_6) are in the noise level (less than 0.01%) of CO_2 estimates.

Table 3-2
Estimated Annual GHG Emissions by Pollutant

Source	tpy				
	CO_2	CH_4	N_2O	SF_6	CO_2e
Turbine Option:					
GE 7FA.05	309,364	0.04057	6.506	--	311,382
GE 7FA.04	272,733	0.03560	5.710	--	274,503
Siemens SGT6-5000F4	299,766	0.04039	6.477	--	301,775
GE LMS100 (2 Units)	325,312	0.04556	7.306	--	327,577
Emergency Generator	128.28	0.00702	--	--	128.43
Circuit Breakers	--	--	--	0.00503	120.10

Notes:

- Emissions of individual GHG compounds (CO_2, CH_4, and N_2O) and the summation CO_2e emissions in this table include the turbine(s), one emergency generator and switchyard breakers, and are based on more detailed estimates in PSD Permit Application Attachment A. CO_2e emissions are calculated using the following GWP's for each GHG compound:

  CO_2: 1

  CH_4: 21

  N_2O: 310

  SF_6: 23,900

- Emission calculations are provided in Attachment A of the Project's PSD Permit Application.

4.1 PSD APPLICABILITY REVIEW

Ecology is the state-level governing body for air quality in Washington. In addition, the state is divided into multiple air pollution control agencies. The Project site is located within the Northwest Clean Air Agency's (NWCAA) authority. The regional air pollution control agencies defer to Ecology for major source attainment permitting issues, such as PSD. The U.S. Environmental Protection Agency (EPA) currently oversees New Source Reviews (NSR) for some PSD pollutants including GHGs.

The existing facility is a PSD major source with potential GHG emissions exceeding 75,000 tpy. The PSD NSR process is required for GHG's from new emission units at major sources when the new units' potential to emit exceeds 75,000 tpy CO_2e (40 CFR 51.166(b)(48)(v)(b)). This is the case for the proposed Project, as shown above in Table 3-1. As a result, BACT is required for the Project's GHG emissions.

PSD rules require a BACT analysis to ensure the use of the most effective air pollution control equipment and procedures. Section 5 of this document presents a thorough BACT analysis, and demonstrates that the Project will meet BACT requirements for GHG. BACT for other PSD pollutants is addressed in Section 5 of the PSD Permit Application.

5.1 INTRODUCTION

40 CFR 51.21(j) defines BACT as emission limits "based on maximum degree of reduction for each pollutant." BACT determinations are made on a case-by-case basis, taking into account energy, environmental, and economic impacts, and other costs.

BACT requirements may be more stringent, but not less stringent than other applicable emission standards. There are presently no GHG emission standards for the Project's proposed sources.

As stated in Section 2.2 above, three air emission source types are proposed for this project:

- Simple cycle gas turbine generator(s), for which four equipment options are being considered by PSE:
  - One GE 7FA.05 frame turbine;
  - One GE 7FA.04 frame turbine;
  - One Siemens SGT6-5000F4 frame turbine; or
  - Two GE LMS 100 aeroderivative turbines.
- A 600 kW emergency generator (Caterpillar with Model C18 ATAAC Tier 2 engine (approximately 890 brake-horsepower (bhp)), or similar make and model).
- Substation breakers containing SF_6.

5.2 BACT ASSESSMENT METHODOLOGY

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency recommended use of a "top-down" methodology for determining BACT. This top-down BACT analysis process consists of five steps (from the EPA's *Draft New Source Review Workshop Manual*, 1990):

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

If the applicant proposes to implement the most effective or "top" available control strategy, Step 4 is not necessary. During PSE's June 16, 2010 preapplication meeting with Ecology and NWCAA staff, it was agreed that PSE's BACT analysis would rely on recent relevant BACT determinations to identify the top current control levels achieved in practice.

Three sources were reviewed to identify relevant BACT determinations for simple cycle gas turbines in the past 5 years (2006 to date):

- EPA's RACT/BACT/LAER Clearinghouse (RBLC),
- California Air Resources Board (CARB) BACT Clearinghouse, and
- Information for California Energy Commission (CEC) power plant siting cases, including local air quality management district findings.

Because BACT determinations generally become increasingly stringent as emission control technology and operating experience improve over time, only projects that were approved in 2006 to date were included in this analysis.

5.2.1 EPA RBLC

BACT determinations identified in the RBLC for large utility-scale simple cycle industrial gas turbine generator units since 2006 are listed in Table 5-1 of the PSD Permit Application. The RBLC contains a wide range of BACT emission limitations. Table 5-2 of the PSD Permit Application summarizes the ranges of BACT emission limits found in the RBLC for various PSD pollutants for natural gas and diesel-fired gas turbines. No top-down BACT determinations for GHGs were found in the RBLC for simple cycle gas turbines.

5.2.2 California BACT Determinations

In addition to evaluating BACT determinations reported in the RBLC, California BACT determinations listed in the CARB Clearinghouse and CEC permitting information were evaluated. California BACT determinations are often more stringent than decisions from other states because California's BACT definition is equivalent to federal Lowest Achievable Emission Rate (LAER) requirements, which does not consider the economic feasibility of control options.

The CARB BACT Clearinghouse was reviewed. This database is no longer regularly updated. The last BACT determination entered into the clearinghouse for utility-scale simple cycle gas turbine was dated 1999. These determinations are considered outdated.

A well-documented source of recent power plant permitting information is the CEC. In California, any new power plant unit similar in size to PSE's proposed project must be certified by the CEC prior to construction. The CEC's power plant siting case list was reviewed to identify similar large utility-scale simple cycle gas turbine power projects (current and past CEC certification projects are summarized at http://www.energy.ca.gov/sitingcases/all_projects.html #approved). Air permits to construct for each identified siting case were reviewed to identify BACT emission limitations. California BACT determinations are summarized in Table 5-3 of the PSD Permit Application. To date, no PSD BACT determinations have been completed for GHG emissions from simple cycle gas turbines in California.

5.3 BACT FOR GAS TURBINES

This section addresses PSD BACT requirements for GHGs that became effective January 2, 2011. Not directly related to BACT, compliance with applicable Washington Administrative Code (WAC) 173-407 performance standard and mitigation requirements for GHGs, is addressed in Section 9 of the PSD Permit Application.

Detailed GHG emissions calculations are provided in Attachments A-1 and A-3 of the PSD Permit Application and results are summarized in Tables 3-1 and 3-2 above. Carbon dioxide (CO_2) is by far the dominant GHG pollutant for the Project. Previous source testing at PSE's Sumas and Mint Farm Generating Stations in 2009 (required by WAC 173-407, and previously reported to Ecology and NWCAA) demonstrated that actual emissions of CH_4 and N_2O combined are less than 0.01% by weight of source-tested CO_2 emission rates. Converted to CO_2e, combined CH_4 and N_2O emissions are less than 1 percent of a gas turbine's CO_2e emissions. CO_2 emissions contribute more than 99 percent of the CO_2e total. (Note: the Sumas and Mint Farm gas turbines both include selective catalytic reduction (SCR) and oxidation catalyst systems. Therefore, it is reasonable to expect a similar emissions relationship for the Project). Even with GWPs of 21 for CH_4 and 310 for N_2O (the GWP of CO_2 is 1), these two pollutants will contribute less than 3 percent to the Project's total CO_2e emissions. For these reasons, this BACT analysis focuses on CO_2 emissions from the gas turbine stack(s).

Although there is no federal new source performance standard (NSPS) for GHGs; the State of Washington has an emission performance standard (EPS) of 1,100 pounds per megawatt-hour (lb/MW-hr) for baseload power plants (WAC 173-407-130). As discussed in Section 9 of the PSD Permit Application, Washington's EPS does not apply to peaking power plants such as the proposed Project.

GHG emissions are a function of fuel consumption which is minimal during start-ups and shutdowns compared to full load operation. The four simple cycle gas turbines proposed for the Project are all capable of achieving fast start-ups and shutdowns, which reduces the effect of start-ups and shutdowns on the GHG emissions. This BACT analysis focuses on normal operating modes (other than start-up and shutdown) which dominate GHG emissions.

BACT for GHGs is determined by the same five step top-down process outlined above for PSD pollutants.

5.3.1 Step 1: Available Control Technologies

According to EPA's recent *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), available control technologies should include lower emitting processes, practices and designs, the use of add-on controls and combinations of the two. However, inherently lower polluting processes that would fundamentally redefine the nature of the sources being proposed by the permit applicant need not be considered. Potentially available control technologies for the Project are summarized below.

Fuel selection. The type of fuel burned determines the amount of GHG pollutants emitted. Viable existing local fuel options for the Project include natural gas and fuel oil. Burning natural gas produces less CO_2 than burning fuel oil due to the lower carbon/hydrogen count in methane. According to EPA AP-42 emission factors, burning distillate fuel oil produces less CH_4 and N_20 emissions than burning natural gas, but higher overall CO_2e emissions.

Fuel efficient engine technology. CO_2e emissions are the direct result of the amount and type of fuel burned. More efficient engines emit less CO_2e relative to the amount of electricity produced. During early project development evaluations, PSE identified seven modern, efficient engine generator options that could be used to satisfy the Project's rapid-start peaking electricity generation. The four simple cycle gas turbine generator models named in this application were considered along with two additional simple cycle gas turbine engine generator models (58 MW

Pratt and Whitney FT8-3's and 41 MW GE LM6000's), plus one reciprocating engine technology (17 MW Wartsila model 18V50DF's). Due to the individual generating capacities of the latter three options, banks of three to ten or more engine generators would be needed to meet the Project's capacity requirements.

Ignoring a longer startup to full load, a combined cycle combustion turbine (CCCT) produces less GHG emissions per MW-hr of electricity generated due to the higher efficiency of the technology; however, it is not an available technology that would meet the Project requirements. As stated previously in this application, the Project objective is to respond to rapidly changing and often short-term peak power demand on PSE's system. Although a CCCT is more efficient for continuous operation applications, simple cycle combustion turbines are best suited for, and are more cost-effective for peaking applications.

The modern CCCT power plant is designed to serve intermediate and baseload electricity generation needs. In other words, they are designed to operate for long periods of time between start and stop than a peaking power plant operates. In PSE's experience combined cycle plants can take anywhere from 3-8 hours to start and reach 100% load, depending on the length of time since the unit was last operated, as they require very careful thermal management to avoid structural damage to the steam generating unit and steam turbines. Because of this long start time characteristic, CCCTs are expensive to start due to the amounts of fuel, back feed electricity and other consumables required to bring the entire unit up to temperature. Accordingly, the operator seeks to run the unit for multiple days, or at the very least, a whole day for each time the unit is started in order to justify the expense of the start. In addition, frequent start-ups generally increase annual maintenance costs for CCCTs and can significantly reduce the time between major maintenance outages which are costly.

Both Siemens and GE have recently announced plans to offer fast start versions of CCCT units that could have the capability to come up to partial load within as few as 10 minutes. However, these are unproven technologies. To PSE's knowledge, neither company has actually constructed and operated a fast start CCCT. This presents substantial technological risk as these types of facilities rarely operate as expected in the first generation. It would not be in the best interest of PSE's ratepayers to take on this type of technology risk. PSE is unwilling to be a "test" customer for such a plant.

In contrast, the simple-cycle turbines that PSE is considering can start and reach stead state operating loads within approximately 10 minutes, and most of the turbine options are well-proven technologies. Note that the GE Frame 7FA.05 is new technology that is yet to be proven in use. PSE's purpose in expanding the FGS is to provide additional "peaking" generating capacity that is capable of responding quickly and reliably to rapid changes in electricity demand. PSE needs to respond to real-time changes in electricity demand, which often means being able to start generators quickly, operate them for a short-period of time, and then stop them, only to restart them again when system demands require.

It may be possible to use these fast start CCCT units to address intermediate electricity generating needs in applications when start times and steady-state load requirements are predictable. However, PSE's peaking generation needs do not fit that profile. In addition the minimum size of vendors' currently proposed new fast start combined cycle units is 270 MW, which is above the capacity that PSE is seeking to meet projected needs. This technology also

currently offers continuous emission guarantees only at approximately 50% load or 135 MW. This higher minimum load would reduce the number of hours at which the Project unit(s) could operate to support PSE's generation system needs.

Using combined cycle technology would require the Project objective to be redefined; therefore, it is not an available technology option for consideration in this BACT evaluation.

Carbon capture and sequestration. According to recent EPA guidance, carbon capture and sequestration (CCS) should be considered a potentially available control option. However, no GHG control technologies are currently demonstrated in practice for simple cycle gas turbines. CO_2 is the dominant carbon compound emitted by the Project's proposed new sources.

As noted above, the EPA RBLC, California BACT Clearinghouse and a review of recent CEC permits did not identify any BACT determinations for GHG emissions from simple cycle gas turbines. Voluntary BACT analyses were performed for two projects permitted in late 2010: the Calpine Russell City Energy Center Project, a combined cycle combustion turbine project, and Portland General Electric's Port Westward II Project, which includes a simple cycle GE LMS100 gas turbine. In both voluntary BACT analyses, CCS was found to be unavailable or infeasible in practice. The use of natural gas as the primary fuel was considered BACT.

PSD Permit Number SE 09-01 was recently issued by EPA Region IX on October 18, 2011 for the Palmdale Hybrid Power Project (PHPP) in southern California. The proposed PHPP includes solar technology and two combined cycle GE Frame 7FA CCCTs to generate electrical power. EPA's BACT analysis for GHG emissions from the CCCTs considered two control technologies: 1) the use of new thermally efficient CCCTs, and 2) the use of CCS. CCS was eliminated as technically infeasible in EPA's BACT analysis (see EPA Region IX. August 2011. Fact Sheet and Ambient Air Quality Impact Report – Palmdale Hybrid Power Project PSD Permit Number SE 09-01, Section 7.1.4). While EPA determined that, in general, CCS is technically feasible, EPA concluded that transport of the captured CO_2 from the PHPP to potential sequestration sites (i.e., by pipeline) was not feasible. As a result, CCS was found not to be technically feasible for the PHPP and was not considered beyond BACT Step 2. Because transport was not feasible, EPA also concluded that it is not necessary to evaluate the feasibility of CO_2 storage. (Note that capture and sequestration options are both analyzed in more detail below for PSE's Project at Ecology's request.) EPA found the use of thermally efficient technology to be BACT for GHG emissions from the PHPP's proposed CCCTs.

Available technologies necessary to capture, compress, transport, inject, and sequester CO_2 from the flue gas of a combustion turbine exist. However, experience with CCS technologies with simple-cycle combustion turbines in peaking applications is limited, and has not been demonstrated in practice for the scale or application similar to the Project's proposed new gas turbine unit(s).

5.3.2 Step 2: Eliminate Technically Infeasible Options

In this step of the BACT analysis, potentially available control technologies are eliminated if they are not feasible for implementation at the proposed Project. In this case, three of the options identified in Step 1 should be eliminated as not feasible for application to the Project.

First, exclusive use of natural gas as fuel is not feasible because there may be times when natural gas is not reasonably available at the Project location, yet PSE may need to operate the Project to

meet its obligation to serve its customers. Instances when backup fuel oil is needed to keep the Project operating will be very infrequent. The Project will be fueled primarily by natural gas.

Second, of the available engine technologies, the Wartsila 18V50DF is not technically feasible at the Project location because it could not satisfy other air permitting requirements. Ambient air quality modeling demonstrated that offsite impacts from the Wartsila 18V50DF engine emissions would significantly exceed the new federal 1-hour nitrogen oxide (NO_x) National Ambient Air Quality Standard (NAAQS) at locations near the FGS.

Third, CCS is not feasible at this Project. As noted below, however, at Ecology's request, CCS will be carried forward into subsequent steps of the BACT analysis.
CCS consists of five stages: (1) capturing CO_2 from the flue gas stream, (2) compressing/drying the CO_2 stream, (3) transporting the CO_2, (4) injecting the CO_2, and (5) permanently sequestering the CO_2.

There are three categories of processes used to capture CO_2 from the flue gas stream: (1) pre-combustion: capture the CO_2 from the fuel prior to combustion, (2) post-combustion: capture the CO_2 from the flue gas stream resulting from the combustion process, and (3) oxy-combustion: perform the combustion process in an environment rich in oxygen instead of air to produce a flue gas that is mostly CO_2. Of the three process categories used to capture CO_2, post-combustion capture is the only option considered potentially ready for commercial application, although, as mentioned previously, CCS has not been demonstrated at scale with simple cycle gas turbines for an application similar to the Project's proposed new unit(s).

The Global CCS Institute publishes lists of active and potential CCS projects. These projects cover a wide range of industries, and capture and storage technologies, and many of them are demonstration projects. Such demonstration projects may have received incentive funding that would have influenced their cost effectiveness. For this BACT Analysis, projects were examined that are in the permitting, construction or operation stages to see if any are similar to the proposed new unit(s) at FGS.

Pre-combustion technology has not been demonstrated in practice for predominantly natural-gas fired gas turbine facilities such as PSE's Project. It would involve costly conversion of natural gas to a non-carbon fuel (i.e., hydrogen), would substantially reduce the overall fuel efficiency of the Project, and more importantly has not been demonstrated to date for gas turbine power generation.

As shown in Table 5-1 only one of the projects evaluated by the Global CCS Institute utilizes post-combustion capture of CO_2 at the Boundary Dam coal fired power plant, and the CO_2 capture portion of the project is still under construction. It has not operated. Furthermore, the economics of capturing CO_2 are substantially different for a coal-fired plant because exhaust gas has a significantly higher concentration of (approximately 13percent) as compared to exhaust from a natural gas power plant (typically about 3 percent). Estimated CO_2 concentrations for the Project, while burning natural gas, range from 3% to 4% for the gas turbine exhaust, and from 2 percent to 4 percent in the stack gas after air has been added to moderate temperatures at the SCR and oxidation catalysts (see Attachment A of the Project's PSD Application). Thus, CO_2 capture at a coal plant is easier and substantially more cost effective than at the Project's

Table 5-1
Large-Scale Integrated CCS Projects Listed by the Global CCS Institute in Permitting, Construction and Operation

Project Name	Location	Industry	Capture Type	Primary Storage Option
Large-scale integrated CCS projects in Operation				
Val Verde Natural Gas Plants (formerly Sharon Ridge)	Texas, USA	Natural Gas Processing	Pre-combustion	Enhanced Oil Recovery
Enid Fertilizer	Oklahoma, USA	Fertilizer Production	Pre-combustion	Enhanced Oil Recovery
Shute Creek Gas Processing Facility	Wyoming, USA	Natural Gas Processing	Pre-combustion	Enhanced Oil Recovery
Sleipner CO2 Injection	North Sea, Norway	Natural Gas Processing	Pre-combustion	Offshore Saline Formations
Great Plains Synfuels Plant and Weyburn-Midale Project	Saskatchewan, Canada	Synthetic Natural Gas	Pre-combustion	Enhanced Oil Recovery
In Salah CO2 Storage	Wilaya de Ouargla, Algeria	Natural Gas Processing	Pre-combustion	Onshore Saline Formations
Snøhvit CO2 Injection	Barents Sea, Norway	Natural Gas Processing	Pre-combustion	Offshore Saline Formations
Century Plant (formerly Occidental Gas Processing Plant)	Texas, USA	Natural Gas Processing	Pre-combustion	Enhanced Oil Recovery
Large-scale integrated CCS projects in Permitting or Construction				
Lost Cabin Gas Plant	Wyoming, USA	Natural Gas Processing	Pre-combustion	Enhanced Oil Recovery
Illinois Industrial Carbon Capture and Sequestration Project	Illinois, USA	Chemical Production	Industrial Separation	Onshore Saline Formations
Boundary Dam Integrated Carbon Capture and Sequestration Demonstration Project	Saskatchewan, Canada	Coal Power Generation	Post-combustion	Enhanced Oil Recovery
Agrium CO2 Capture with ACTL	Alberta, Canada	Fertilizer Production	Pre-combustion	Enhanced Oil Recovery
Kemper County IGCC Project (formerly Plant Ratcliffe)	Mississippi, USA	IGCC Power Generation	Pre-combustion	Enhanced Oil Recovery
Gorgon Carbon Dioxide Injection Project	Western Australia	Natural Gas Processing	Pre-combustion	Onshore Saline Formations

Source: Global CCS Institute 2011, The global status of CCS: 2011, Canberra, Australia

predominantly gas-fired combustion turbine(s). In summary, the post-combustion CO_2 capture implemented at the Boundary Dam power plant is unproven to date and not directly comparable

to PSE's proposed Project. Operational cost effectiveness data are neither readily available for the Boundary Dam nor would they be applicable to the proposed Project.

The Global CCS Institute's list does not include a handful of post-combustion CO_2 capture and storage demonstration projects that were built and operated over the years, but are no longer in operation due to economic reasons. Readily available information is summarized in Table 5-2 for several projects. The primary source of exhaust from these projects varied considerably, although most are not comparable to the proposed Project, and all stopped when capture and sequestration were no longer economically feasible. Three of these projects include/included gas turbines. The Mitchell Energy project involved a range of combustion devices, one of which was a gas turbine. Sufficient data were not readily available to assess the similarity of the post-combustion capture for the Mitchell Energy project as compared to the proposed Project; however, it is known that CO_2 capture and sequestration stopped at the Mitchell Energy facility when it was no longer economically feasible. Two proposed natural gas CCCT power plant projects in Table 5-2 are located in Norway and were slated to include post-combustion CO_2 capture; one is operational without CCS, the other project is on hold. Due to project economics and funding uncertainties, neither of the Norwegian projects has implemented CCS.

PSE is aware of a capture technology that was developed and tested on a demonstration scale at a Florida Power and Light (FP&L) natural gas turbine power plant in Bellingham, Massachusetts. Compared to other projects in Tables 5-1 and 5-2, FP&L's project appears to be more similar to PSE's proposed Project, so it is discussed in greater detail below. The Bellingham cogeneration plant (now jointly owned by NextEra Energy and SUEZ Energy Generation) consists of two Siemens Westinghouse W501D5 combustion turbines, two heat recovery steam generations, and a steam turbine in a combined cycle configuration (EPA, 2006. *Application for Fuel Oil Flexibility Bellingham Cogeneration Facility.* Reviewed on June 23, 2011). Fluor's Econoamine FG process was operated on a fraction of this facility's exhaust for 14 years from 1991 to 2005. Operation of the control device ceased after increased natural gas prices in 2004-2005 forced the unit "to operate in peak load shaving mode which rendered the capture plant uneconomical" (Fluor Corporation, 2011. *Econamine FG Plus FAQs*. Reviewed on June 6, 2011; from: http://www.fluor.com/econoamine/Pages/faqs.aspx). The Bellingham cogeneration plant did not operate as a peaking plant during the 14 years when the Econoamine process was in operation. Apparently, continued operation of the Econoamine FG system became infeasible when power plant operation changed from baseload operation to peaking operation. Sequestration was not attempted at the Bellingham plant. The plant's captured CO_2 was transported offsite by truck for sale during the demonstration project; this is not a viable option for the Project since a peaking facility would be an inconsistent and unreliable source of CO_2 for sale.

PSE believes that this technology remains in a class of demonstration projects for combined cycle facilities, and remains undemonstrated for simple cycle peaking applications to date. However, for the purposes of this BACT analysis, CCS is considered in Step 3 at the request of Ecology and EPA.

Table 5-2
Other Post-Combustion CCS Projects not Listed by the Global CCS Institute – Proposed or with Operational Experience

Project Name	Location	Industry	Capture Type	Primary Storage Option	Operating Date	Comments/Status	References
AEP Mountaineer	West Virginia, USA	Coal Power Generation	Post-combustion	Onshore Saline Formations	Operated pilot project from September 2009 to May 2011	Due to the current uncertain status of U.S. climate policy and the continued weak economy, the project was put on hold.	http://www.aep.com/environmental/climatechange/carboncapture/
Lubbock, Texas	Lubbock, Texas	Gas boiler	Post-combustion	Enhanced Oil Recovery (EOR)	Operated 1982-1984. Now closed	Shut down when EOR was rendered uneconomical, Captured 1200 ton/day CO2	http://www.worleyparsons.com/CSG/Hydrocarbons/SpecialtyCapabilities/Documents/Carbon%20Capture%20Overview%20(3).pdf and ENERGY INSTITUTE, LONDON, Good plant design and operation for onshore carbon capture installations and onshore pipelines, Sept 2010
Mitchell Energy	Bridgeport, Texas	Gas heaters, engines, turbines	Post-combustion	Enhanced Oil Recovery	Operated 1991-1999. Now closed	Captured 500 ton/day CO2, shut down when EOR was rendered uneconomical	http://www.worleyparsons.com/CSG/Hydrocarbons/SpecialtyCapabilities/Documents/Carbon%20Capture%20Overview%20(3).pdf and ENERGY INSTITUTE, LONDON, Good plant design and operation for onshore carbon capture installations and onshore pipelines, Sept 2010
N-ReN Southwest	Carlsbad, NM	Gas boiler plus NH3 reformer exhaust	Post-combustion	Enhanced Oil Recovery	Closed in 1990s	Captured 104 ton/day of CO2, bud shut down due to economic reasons	http://www.me.unm.edu/~mammoli/MIE561_stuff/economics_in_technology.pdf and ENERGY INSTITUTE, LONDON, Good plant design and operation for onshore carbon capture installations and onshore pipelines, Sept 2010
Naturkraft Karsto Power Plant	Karsto, Norway	Natural Gas Combined Cycle	Post-combustion	Aquifers	Opened in 2007 without CCS. CCS postponed indefinitely	Although the plant was built without gas scrubbing for CO2 emissions, this may be installed later.	http://www.power-technology.com/projects/karsto/
Statoil Mongstad	Mongstad, Norway	Natural Gas Combined Cycle	Post-combustion	Saline Formations	2012 proposed operation date for demonstration project.	Funding for commercial operations pushed back until 2016, and still uncertain.	http://sequestration.mit.edu/tools/projects/index.html

Potential Sequestration Options. Potential alternatives for CO_2 sequestration are listed below and their feasibilities in western Washington State are briefly reviewed. Washington rules (WAC 173-407-110) require that permanent sequestration achieve the "retention of greenhouse gases in a containment system using a method that is in accordance with standards approved by the department and that creates a high degree of confidence that substantially ninety-nine percent of the greenhouse gases will remain contained for at least one thousand years." This requirement is a consideration in the following review.

Enhanced Oil Recovery – CO_2 has been used in other regions of North America (e.g., southern California, eastern Texas, and southern Alberta) and in other parts of the world to supplement enhanced oil and natural gas recovery (EOR) operations to recover additional oil from geologic formations that are no longer productive using typical drill and pump techniques. Note that other locations are also proposing or using compressed CO_2 to recover methane from unminable coal beds. For use in EOR, the CO_2 must be compressed, transported in large quantities (usually by pipeline), and injected into the well fields. Due to the lack of oil and gas production areas, EOR opportunities do not exist in the Pacific Northwest and pipelines do not exist for the transportation of CO_2 to distant EOR operations. Based on the known geology of existing coal fields in Washington, it is unlikely that injection into coal beds would satisfy the regulatory definition of "permanent sequestration" quoted above. Developing a pipeline for this project would be a very expensive and time-consuming proposition. Furthermore, the feasibility of obtaining, permits, land, rights-of-way and easements for a long pipeline to EOR fields is uncertain. Also note that not every oil field would satisfy Washington's requirements for permanent sequestration. The CO_2 acts like a solvent and is recovered along with the oil. The recovered CO_2 would need to be separated and reinjection or reused consumptively, and formation and oil field equipment would need to be reasonably leak proof.

Geologic Sequestration – Geologic sequestration technologies other than EOR have been proposed and some are currently under research and development. CO_2 sequestration is performed at Sleipner in the North Sea, Snøhvit in the Barents Sea, In Salah in Algeria, and Weyburn in Canada[1] for the primary purpose of EOR. No geological sequestration project has yet demonstrated long-term operation at the scale required for this Project solely for the purpose of CO_2 sequestration. For example, deep saline formations could store CO_2 for long periods of time if sufficiently capped by impermeable layers. Deep saline formations are not a viable option in western Washington, as geologic faulting and fractures raise the question whether storage would meet Washington's permanency requirement. The region is highly active tectonically. As a result, very few formations in this area are likely to be free of fractures and faults that might serve as pathways for the CO_2 to migrate. PSE understands that insufficient deep-hole geophysics data are available to confirm the viability of deep injection options in western WA.

Another geologic sequestration example is CO_2 injection into deep basalt formations that underlie tight capping formations. This option is currently being researched by Battelle in southern Washington State. Such basalt formations are not available within a reasonable distance of the Project site. In theory, a third geologic sequestration option would be to compress,

[1] Report of the Interagency Task Force on Carbon Capture and Storage, US EPA, OAR, Climate Change Division, August 2010

transport and inject liquid CO_2 deep into the tectonic subduction zone offshore in the Pacific where ocean waters are deep.

In all three cases, the CO_2 would need to be compressed, transported long distances (200 miles or more) and injected. As mentioned above, CO_2 pipelines do not exist in Washington. All three of these geologic sequestration approaches are innovative technologies that have not been demonstrated in practice.

Silicate Mineral Reactions – Research has shown that some ultramafic minerals (e.g., olivine or serpentinite) can be reacted with CO_2 to form stable solid (carbonate) compounds. A source of such silicate materials exists in northwestern Washington, but the mineral deposit is undeveloped, making the mineral unavailable for the Project. Until such time as the deposit is developed, the minerals, would need to be transported to the Project site from a long distance (likely by rail) and the resultant solid waste would need to be disposed. Due to the nature of the process to react the collected CO_2 with the silicate minerals, the emission control project would be of a larger physical scale than the Project itself, requiring additional land, development of rail access to the site, etc. A relatively large landfill would need to be developed or an existing landfill of sufficient capacity would need to be used. There are no existing rail transport or disposal sites at or adjacent to the FGS site to support these activities.

Industrial Reuse – In theory CO_2 from the project could be sold for industrial reuse. However, to meet Washington State requirements for permanent sequestration, that use would need to be permanently consumptive (i.e., not rereleased into the atmosphere). Typical industrial uses such as welding operations that use CO_2 as a shielding gas, or dry ice manufacturing eventually result the CO_2 being released back into the atmosphere. Thus, typical industrial usages of CO_2 do not qualify as permanent sequestration and would not reduce CO_2 emissions. No large-volume permanently-consumptive CO_2 industrial uses are known to exist near the Project site, and no pipeline systems are locally available to transport it, as stated above.

Note also that additional CO_2 emissions would result from compression, long-range transport and disposal related to the options listed above.

Although PSE does not consider these CCS technologies to be feasible for the FGS expansion project, they are carried forward into the next step of the BACT analysis at Ecology's request.

5.3.3 Step 3: Rank Remaining Control Options

The remaining control options consist of CCS, fuel choice, and turbine/engine efficiency. PSE proposes to use the least emitting feasible fuel choice, which is to fuel the Project primarily with natural gas, using ULSD only when natural gas is not reasonably available. Based on the FGS's operating history, PSE expects fuel oil use to be very infrequent and proposes to limit ULSD total annual use to no more than 336 hours (per turbine for the GE LMS100 option).

CO_2 capture processes are currently limited to 90 percent or less removal of CO_2 from the flue gas stream of a power plant. Therefore, the maximum CO_2 capture rate assumed for this analysis is 90 percent of the CO_2 produced during the combustion process. The CO_2 capture and compression processes are energy intensive. If the Project's proposed unit(s) had CCS, an estimated 7 percent of the gross electricity produced would be consumed by these two processes alone. Due to increased auxiliary electric load required to operate the CCS systems, and resultant

increased fuel used to meet the increased auxiliary electric load, the net reduction in CO_2 emissions per net MW-hr would be less than 90 percent. CO_2 capture processes have not been proven to reduce/remove other GHGs such as CH_4, SF_6, and N_2O. After accounting for these factors, application of post-combustion CO_2 capture would achieve at most an estimated 88.5 percent reduction in CO_2e emissions.

Tables 5-3 and 5-4 compare and rank PSE's six feasible turbine options based on their estimated efficiencies and CO_2e emissions in lb/MW-hr of electricity generated, without CCS and with CCS, respectively. The rank order is the same with and without CCS. Estimated fuel efficiency decreases (i.e., heat rate is higher) when CCS is included, resulting in approximately 7 to 8 percent more fuel being burned per MW-hr for each engine option. When CCS is excluded in the analysis, the six turbine options fall within a CO_2e emissions efficiency range of 1,052 to 1,235 lb/MW-hr. When CCS is included in the analysis, the six turbine options fall within a CO_2e emissions efficiency range of 120 to 143 lb/MW-hr.

Table 5-3
Efficiency and CO_2e Emissions from Available Turbine Options without CCS[(1)]

PEAKER ALTERNATIVES	LMS-100	LM-6000	7FA.05	5000F4	7FA.04	FT8-3
Manufacturer	GE	GE	GE	Siemens	GE	P&W
Technology	Aero	Aero	Frame	Frame	Frame	Aero
Heat rate @ Full-Load (Btu/KWh (HHV))	9,007	9,871	10,145	10,152	10,193	10,570
Fuel CO_2 Content (lb/MMBtu (HHV))[(2)]	115.9	115.9	115.9	115.9	115.9	115.9
Fuel CO_2e[(2)(3)] (lb/MMBtu (HHV))	116.8	116.8	116.8	116.8	116.8	116.8
CO_2e Emissions (lb/MWh)	1,052	1,153	1,185	1,186	1,191	1,235
Rank (1= lowest emitting)	1	2	3	4	5	6

[(1)] CCS = CO_2 capture, compression, and sequestration.

[(2)] The fuel CO_2 content is based on the following design assumptions and calculations: (HHV = higher heating value)

Natural Gas – The Project's design natural gas fuel is 74.22 wt-% carbon with a higher heating value of 23,473 Btu/lb.
lb-CO2/MMBtu (HHV) = (0.7422 lb-carbon / 1.0 lb-fuel) * (1 lb-fuel / 23,473 Btu-HHV) * (1,000,000 Btu / 1 MMBtu) * (44.01 lb/lbmol-CO2 / 12.01 lb/lbmol-carbon) = 115.9 lb/MMBtu (HHV)

ULSD – The Project's design distillate fuel is 87.16 wt-% carbon with a higher heating value of 19,550 Btu/lb.
lb-CO2/MMBtu (HHV) = (0.8716 lb-carbon / 1.0 lb-fuel) * (1 lb-fuel / 19,550 Btu-HHV) * (1,000,000 Btu / 1 MMBtu) * (44.01 lb/lbmol-CO2 / 12.01 lb/lbmol-carbon) = 163.4 lb/MMBtu (HHV)

[(3)] In compliance with WAC 173-407-120, 173-407-140, and 173-407-230, four quarterly source tests were performed by URS for PSE in 2009 to measure N_20, CH_4 and CO_2 emissions at the Mint Farm and Sumas Generating Stations, and the test results were submitted to Washington Department of Ecology that year. Based on those source tests, CO_2 emissions account for approx. 99.27% of total CO_2e emissions. Therefore, total CO_2e = 115.9 / 0.9927 = 116.8 lb/MMBtu (HHV) without CCS for calculations in this table.

Notes:

- For consistency, heat rate estimates are based on ISO conditions and were used for the preliminary technology screening process.

Table 5-4
Efficiency and CO_2e Emissions from Available Turbine Options with 90% CCS[1]

PEAKER ALTERNATIVES	LMS-100	LM-6000	7FA.05	5000F4	7FA.04	FT8-3
Manufacturer	GE	GE	GE	Siemens	GE	P&W
Technology	Aero	Aero	Frame	Frame	Frame	Aero
Heat rate @ Full-Load (Btu/KWh (HHV))	9,647	10,645	10,973	10,965	11,021	11,463
Fuel CO_2 Content (lb/MMBtu (HHV))	11.6	11.6	11.6	11.6	11.6	11.6
Fuel CO_2e[2] (lb/MMBtu (HHV))	12.5	12.5	12.5	12.5	12.5	12.5
CO_2e Emissions (lb/MWh)	120	133	137	137	138	143
Rank (1= lowest emitting)	1	2	3	4	5	6

[1] CCS – CO_2 capture, compression, and sequestration.

[2] Based on 2009 source testing at PSE's Mint Farm and Sumas Generating Stations, CO_2 emissions account for approx. 99.27% of total CO_2e emissions. Therefore, total CO_2e = 115.9 / 0.9927 = 116.8 lb/MMBtu (HHV) without CCS.

Notes:

- For consistency, heat rate estimates are based on ISO conditions and were used for the preliminary technology screening process.
- HHV = higher heating value.

The least efficient, highest emitting option is the Pratt & Whitney FT8-3. Because this turbine option is also one of the most expensive and offered no significant advantages, PSE dropped it from further consideration during preliminary engineering evaluations. The remaining five turbine options emit significantly less CO_2e per MW-hr and are, therefore, considered to be the "most effective controls" for analysis in Step 4.

5.3.4 Step 4: Evaluate Most Effective Controls and Document Results

In this step, the options found to be the most effective at minimizing CO_2e emissions and considered technically feasible were further evaluated relative to their emission performance and cost effectiveness.

As mentioned above, the technologies necessary to capture, compress, transport, inject, and sequester CO_2 from the flue gas of a combustion turbine exist but have not been demonstrated at a scale or application similar to the Project's proposed new unit(s). Because CCS is not feasible for the FGS expansion project, PSE has not attempted a project-specific or site-specific cost estimate for implementing one of the CCS options discussed above. Instead, PSE considered cost estimates prepared by others. PSE is not aware of any studies where estimates of cost and performance impacts associated with the addition of CCS systems to a simple cycle combustion turbine were developed and therefore was not able to use such estimates as part of this analysis. In November 2010, the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) published cost and performance estimates for fossil fueled power plants with and without CCS systems installed. For a net 550 MW natural gas-fired combined cycle plant, NETL estimated a $76 per ton cost of CO_2 avoided using post-combustion CCS compared to an

analogous combined cycle plant without CCS (NETL, *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) [2]. An explanation of the term "cost of CO_2 avoided" is provided in Attachment A. This is more than three times the $20 per ton CO_2e approximate social cost of carbon recently cited by EPA (EPA Office of Air Quality Planning and Standards (OAQPS), June 17, 2011) Panel Outreach Meeting with SERs: *Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units* (page 62)), and it exceeds, by an even larger factor, the $7 per ton recently proposed BACT threshold for the Kalama Energy Center (Environ, *Combined-Cycle Combustion Turbine Project Greenhouse Gas Best Available Control Technology Analysis*, Kalama Energy Center. Prepared for Kalama Energy Center, LLC, June 2011).

There are a number of important differences between a combined cycle power plant such as the plant concept presented in the DOE-NETL report, and a simple cycle combustion turbine power plant such as the Project's proposed new unit(s). These differences, as discussed below, further increase the actual cost per ton of CO_2 avoided above the $76 per ton value cited for combined cycle plants:

- The DOE-NETL combined cycle concept was assumed to operate as a base-loaded plant, with a capacity factor of 85 percent (equivalent to 7,446 hours at full load). The proposed new unit(s) would operate as a peaking unit with expected hours of operation of no more than 3,200 hours per turbine annually (2,400 hours for the frame turbine options). Capital expenses and other fixed costs would be spread over far fewer operating hours for a peaking unit compared to a base-loaded plant, resulting in a higher cost per ton CO_2 avoided.

- The CO_2 capture system would require process steam. The DOE-NETL combined cycle concept utilized steam from the steam cycle portion of the plant. The proposed new unit(s) at FGS will not have a steam source. Addition of either heat recovery steam generators (HRSG) or an auxiliary boiler would be required to supply process steam to the CO_2 capture system. Such additions would increase the cost per ton CO_2 avoided.
- The CO_2 capture and compression systems would require a heat rejection system to dissipate process heat. The DOE-NETL combined cycle concept already had a large circulating water system and cooling tower to reject heat from the steam cycle. Additional heat rejection duty was accomplished by the addition of several cells to the cooling tower and a corresponding increase in circulating water flow rates. It is likely that a dedicated heat rejection system would be required to dissipate sufficient process heat from the CO_2 capture and compression systems for the proposed new unit(s) at FGS. In addition, the DOE-NETL combined cycle concept had a flue gas temperature of 290°F, which was cooled to 85°F with heat being rejected to the atmosphere through the heat

[2] There are multiple conflicting cost values in the NETL study. In a September 27, 2011 email to URS Corporation, the principal study author, Mr. James Black, confirmed that $76 is the correct value for CCS applications with natural gas-fired combined cycle gas turbines. Mr. Black also confirmed that he is not aware of any cost numbers for simple cycle gas turbine applications.

rejection system. The flue gas temperature for the proposed new unit(s) at FGS will range from 741°F to over 1,100°F, depending on the turbine, ambient conditions, and turbine load. Cooling the flue gas to temperatures approaching 85°F would require a heat rejection system with a cooling duty many times greater than the cooling duty required for the CO_2 capture and compression systems for the DOE-NETL combined cycle concept. These two factors combined would significantly increase the heat rejection system cost for the proposed new unit(s) at FGS compared to the costs presented in the DOE-NETL report.

- The DOE-NETL report assumed a CO_2 transport distance of 50 miles via pipeline with injection into a saline formation at a depth of 4,055 feet and characteristics conducive to introducing large quantities of CO_2 for permanent sequestration. PSE is not aware of any such geologic formations available within a 50 mile radius of the facility. The distance between the FGS facility and a suitable geologic formation would impact the project cost.
- The DOE-NETL combined cycle concept required a CCS system about twice as large as the CCS system for the proposed new unit(s) at FGS. Economy of scale would result in higher project costs per ton of CO_2 captured for the proposed new unit(s) at FGS compared to the DOE-NETL concept.

The cost per ton of CO_2 avoided is much higher than currently acceptable economic thresholds. CCS systems are, therefore, found to be not cost effective and were removed from further consideration in this BACT analysis for GHGs.

Given that carbon capture, alone, is demonstrated in the above analysis not to be economically viable for the Project and any of the sequestration options listed in Step 3 would add significantly to the cost, further analysis of sequestration is not warranted for this BACT analysis.

The five most efficient available and feasible turbine generator options in Tables 5-3 and 5-4 are evaluated below for relative emission performance and cost effectiveness without the addition of CCS. All five options are very efficient. As explained above, the Project will use the most effective feasible fuel choice for any of the turbine generator options.

In order to make an apples-to-apples comparison of the cost of CO_2e reduction, this evaluation assumes that using any of the five options, the Project would generate 131,400 MW-hrs of electricity per year, and that natural gas would be used as the fuel. Total CO_2e emissions and annual costs (using standard book life and discount rate assumptions) were calculated for each option. In order to determine the marginal cost per ton of additional CO_2e removed, the analysis considers the fifth-ranked option to be the base case, and determines the cost per ton of additional CO_2e emissions avoided for the other four options.

Table 5-5 summarizes the cost analysis. For purposes of calculating the cost of incremental CO_2e removal, the analysis treats the 7FA.04 as the base case, and calculates the additional cost per ton of using the other turbine models to further reduce CO_2e emissions. The analysis shows that further CO_2e reductions would cost between $710 and $4,660 per ton of CO_2e removed.

5.3.5 Step 5: Select the BACT

Ecology has requested that this BACT analysis include an evaluation of the different turbine options. Such an evaluation is fundamentally different than a traditional BACT analysis for criteria pollutants. In a traditional BACT analysis, the relative effectiveness of add-on pollution

control technologies is considered. Here, however, different choices for the primary project equipment are evaluated. It should be kept in mind that EPA has never taken the position that BACT requires an applicant to purchase a particular make and model of turbine engine for an electric generating facility. In fact, at this point in the development of the Project, PSE has not selected a single make or model. PSE's ultimate decision about which turbine engines to install will depend upon a variety considerations, including equipment availability, cost, start-up time, operational performance, reliability and maintenance issues. PSE may, for example, decide to use a more expensive model because of operational or maintenance advantages provided by the more expensive model. Moreover, some turbine models that appear to be available and technically feasible today may prove to be unavailable or infeasible by the time PSE is ready to begin construction.

Cost benefit guidance for GHG BACT has not been provided by EPA to date for simple cycle gas peaking turbines. The cost effectiveness evaluation in Step 4 demonstrates that a CO_2e emission rate of 1,191 lb/MW-hr from the 7FA.04 turbine base case satisfies BACT. The $710 to $4,660 per ton cost associated with additional CO_2e emission reduction using alternative turbines is far in excess of costs ordinarily considered "achievable" in traditional BACT analyses. Indeed, such incremental costs are orders of magnitude higher than the current market price of CO_2 offsets. These incremental costs greatly exceed the $20 per ton CO_2e approximate social cost of carbon and, by an even greater margin, the recently proposed $7 per ton GHG cost-effectiveness threshold cited above in Section 5.3.4. PSE contends that all of the top five turbine models identified in Table 5-5 satisfy BACT requirements for GHG. Not only would it be inappropriate to require a project to use a specific turbine model, but in this case, the relative costs and environmental impacts of the different models make it inappropriate to exclude any of them.

PSE proposes to use any one of four most cost effective turbine models in Table 5-5. The most expensive option, the LM6000, will not be pursued for the Project. Therefore, PSE requests approval to implement any one of the following four highly efficient gas turbine options: the GE

F7A.04, GE F7A.05, Siemens SGT6-5000F4, and GE LMS100, all of which meet or exceed the proposed BACT emission rate of 1,191 lbs/MW-hr CO_2e.

5.4 BACT FOR SWITCHYARD BREAKERS

As stated previously, the Project's proposed new 230 kV switchyard will include 10 new SF_6-filled breakers. A small amount of the GHG pollutant SF_6 is emitted from switchyard breakers as a result of unavoidable leakage.

For the October 18, 2011 PHPP PSD permit cited above, EPA Region IX evaluated two technologies: 1) dielectric oil or compressed air circuit breakers, and 2) enclosed-pressure SF_6 circuit breakers with 0.5% annual leakage rate and leak detection systems. EPA eliminated the first technology based on potential adverse environmental and energy impacts. The second technology was selected as BACT (see EPA Region IX. August 2011. Fact Sheet and Ambient Air Quality Impact Report – Palmdale Hybrid Power Project PSD Permit Number SE 09-01, Section 7.6.1).

5.4.1 Step 1: Available Control Technologies

Two types of breakers are commercially available for high-voltage utility switchyard applications: SF_6-filled and oil-filled. Modern breakers are designed with efficient seals to

Table 5-5
Incremental Emission Reduction Cost Analysis for Five Turbine Options

	LMS100	LM-6000	7FA.05	5000F4	7FA.04
Emissions Calculations					
Plant Capacity, net (MW)	199.7	165.1	209.4	207.1	182.3
Generation (MW-hr), 200MW @ 7.5%CF	131,400	131,400	131,400	131,400	131,400
Heat rate, net (Btu/kWh, HHV)	9,007	9,871	10,145	10,152	10,193
Fuel CO_2 Rate (lb/MMBtu, HHV)	115.9	115.9	115.9	115.9	115.9
Fuel CO_2e Rate (lb/MMBtu, HHV)	116.8	116.8	116.8	116.8	116.8
Plant CO_2e Emissions Rate (lb/MW-hr)	1,052	1,153	1,185	1,186	1,191
Annual CO_2e Emissions (tons/yr)	69,118	75,748	77,850	77,904	78,219
Emissions Rank (1 = lowest emitting)	1	2	3	4	5
CO_2e Reduction from Base Unit (tons/yr)	9,101	2,471	368	315	0
Cost Calculations					
Plant Book Life (yrs)	35	35	35	35	35
PSE Discount Rate	8.10%	8.10%	8.10%	8.10%	8.10%
Annual O&M					
Fixed O&M (FOM) ($/kW-yr)	15.71	19.06	11.48	11.76	12.32
First-Year FOM ($/yr)	3,136,522	3,146,952	2,403,015	2,436,339	2,246,140
FOM Escalation Rate[1](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
FOM Levelized Cost ($/yr)	4,063,695	4,998,100	3,113,360	3,156,534	2,910,111
Variable O&M (VOM) ($/MW-hr)	3.58	4.34	11.88	10.28	10.68
First Year VOM ($/yr)	470,713	570,584	1,560,650	1,350,846	1,402,785
VOM Escalation Rate[1](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
VOM Levelized Cost ($/yr)	609,858	906,221	2,021,987	1,750,164	1,817,457
Fuel ($/MMBtu, HHV)	8.08	8.08	8.08	8.08	8.08
First Year Fuel ($/yr)	9,562,840	10,480,159	10,771,068	10,778,500	10,822,030
Fuel Escalation Rate[1](%/yr)	3.00%	3.00%	3.00%	3.00%	3.00%
Fuel Levelized Cost ($/yr)	12,389,669	16,644,959	13,955,056	13,964,685	14,021,083
All-In CapEx ($)	279,000,000	274,000,000	198,000,000	191,000,000	185,000,000
Capital Recover Factor, (%)	*8.67%*	*8.67%*	*8.67%*	*8.67%*	*8.67%*
Annual CapEx ($/yr)	24,182,437	23,749,060	17,161,729	16,555,002	16,034,949
Total Levelized Annual Cost ($/yr)	41,245,660	46,298,340	36,252,133	35,426,384	34,783,600
Levelized Cost (Savings) Over Base ($/yr)	6,462,059	11,514,739	1,468,532	642,784	$0
Incremental Cost-Effectiveness ($/ton CO_2e)	$710	$4,660	$3,987	$2,043	$0

[1] PSE assumes an escalation rate of 3% as an average inflationary number. This number falls within the range of historical inflation.

minimize SF_6 leakage. Limited lifetime guarantees offered by breaker manufacturers address seal performance during the guaranteed life of the equipment. PSE experience indicates that SF_6 leakage is immeasurable during the guarantee period. The 0.5% annual leakage rate used in this application to estimate SF_6 emissions is conservatively high.

5.4.2 Step 2: Eliminate Technically Infeasible Options

Both breaker types are technically feasible.

5.4.3 Step 3: Rank Remaining Control Options

Oil-filled breakers are ranked as the top control option because they do not emit any GHGs.

5.4.4 Step 4: Evaluate Most Effective Controls and Document Results

Although oil-filled breakers contain/emit no GHGs, oil presents other environmental and safety risks. An oil release and/or fire could result in the event of overheating and rupture of the breaker. SF_6 has also proven to be a more effective insulating medium, and therefore, SF_6 breakers have proven to be more reliable.

5.4.5 Step 5: Select the BACT

Based on industry experience, PSE strongly prefers SF_6-filled breakers for reliability and safety reasons. In order to minimize chances of SF_6 leakage into the atmosphere, PSE proposes to follow manufacturer recommended procedures and schedules for operation, maintenance, and replacement of these breakers. In addition, PSE will double check new breaker units for leakage prior to placing them into service, and will perform monthly internal gas pressure checks on all in-service breakers. Breakers found to be leaking will be serviced to stop the leak or replaced as appropriate.

5.5 BACT FOR EMERGENCY GENERATORS

A diesel-fired generator is proposed as the only technically feasible option. A natural gas-fired generator technology is not a feasible option because there is a risk of significant damage to the gas turbine(s) and other power plant systems if a power grid outage occurred at the same time as a natural gas outage, such as in the event of a strong earthquake.

Emergency generator BACT determinations are much less common than gas turbines. Current BACT guidelines and determinations published in the RBLC and by California Districts. Current Bay Area Air Quality Management District (BAAQMD), South Coast Air Quality Management District (SCAQMD) and San Joaquin Valley Air Pollution Control District (SJVAPCD) BACT guidelines require new stationary emergency compression ignition (CI) engines to meet applicable EPA NSPS or CARB tier standards for non-GHG air pollutants. Federal Tier 2 standards for non-road CI engines currently apply to new stationary emergency standby engines greater than 761 bhp, or 560 brake-kilowatt (bkW) (EPA, *Final New Source Performance Standards for Stationary Compression Ignition Combustion Engines*, 71 FR 39154. July 11, 2006). Note that emergency engines are exempt from the more stringent Tier 4 requirements in the NSPS. PSE is not aware of any GHG BACT determinations or emission standards to date that apply to GHGs for emergency standby CI engines.

For the October 18, 2011 PHPP PSD permit cited above, EPA Region IX assumed that newly purchased engines would be the most energy efficient available and that operating in compliance with NSPS requirements (for other pollutants) will ensure proper maintenance, thereby maintaining efficiency (see EPA Region IX. August 2011. Fact Sheet and Ambient Air Quality Impact Report – Palmdale Hybrid Power Project PSD Permit Number SE 09-01, Section 7.3.1).

At time of purchase, the Project's proposed new emergency standby generator engine will be certified by the manufacturer to meet Tier 2 standards. The Caterpillar engine identified in Section 5.1 and Attachment A-9 of the PSD Permit Application meets these standards, If a different make/model emergency standby generator is selected during detailed design for the Project, a Tier 2 certified engine will be specified at time of purchase.

For GHG BACT purposes, the proposed emergency generator will be operated so infrequently that any change in engine efficiency would have little effect on Project emissions. CO_2 emissions from scheduled testing of the emergency generator are estimated to be about 24 tpy (see Permit Application Attachment A-12 for estimated hourly emission rates). Actual emergency use, which cannot be reliably predicted, is not included in this emission estimate. Therefore, the proposed emergency standby generator meets BACT.

The "cost of CO_2 avoided" is a metric used to show how implementing CO_2 emission controls increases or decreases the cost required to produce electricity. A negative cost per CO_2 avoided would indicate that reducing CO_2 emissions produces electricity cost savings. A positive cost per CO_2 avoided indicates that reducing CO_2 emissions increases the cost of electricity produced.

Following is an explanation of how the cost of CO_2 avoided is calculated. The influences that changes in power plant capital cost and operating hours have on the cost of CO_2 avoided are also explained, specifically when it comes to implementing CCS processes for electricity generation technologies.

The cost of CO_2 avoided is a function of the increase or decrease in the cost of electricity to reduce CO_2 emissions, measured in $ per MW-hr, divided by the reduction in CO_2 emissions realized:

$$\text{Cost } CO_2 \text{ Avoided } (\$/\text{ton}) = \frac{\text{Electricity Cost with CCS} - \text{Electricity Cost without CCS } (\$/\text{MW-hr})}{CO_2 \text{ emissions without CCS} - CO_2 \text{ emissions with CCS (tons/MW-hr)}}$$

The cost of electricity is a function of the expenses of a power plant over time, measured in $ per year or $ per hour, divided by the amount of electricity sold by the plant over that same period of time. The expenses of a power plant are comprised of four basic components: the cost of capital (analogous to a mortgage payment on a house), the fixed operating cost (mainly plant staffing expenses), variable operating costs (e.g., water, chemicals, and other maintenance costs resulting from wear and tear), and fuel costs (natural gas or ULSD in this case).

$$\text{Cost of Electricity } (\$/\text{MW-hr}) = \frac{\text{Cost of Capital + Fixed/Variable Operating Costs + Fuel Cost } (\$)}{\text{Net Amount of Electricity Produced (MW-hr)}}$$

The greater the capital cost difference between a power plant without CCS and a power plant with CCS, the greater the cost of CO_2 avoided. In addition, the less electricity produced by a plant over a given time period, the greater the cost of CO_2-avoided. As discussed in Section 5.3.4, both of these trends occur when comparing a base loaded combined cycle power plant with a peaking simple cycle power plant.