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Prevention of Significant Deterioration and Air Discharge Permit Application for a Combined Cycle Combustion Turbine Project

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1 Introduction

Energy Northwest proposes to construct Kalama Energy Center, a natural gas-fired combined cycle electrical generation station at the Port of Kalama. Based on the expected maximum annual potential for the completed facility to emit air pollutants, the facility would be a major source as defined by the Prevention of Significant Deterioration (PSD) program. As a major PSD source, permitting falls under the jurisdiction of both the Washington Department of Ecology (Ecology) and the Southwest Clean Air Agency (SWCAA). Energy Northwest has retained ENVIRON International Corp. (ENVIRON) to prepare this combined PSD and Air Discharge Permit (ADP) Application (also known as a "Notice of Construction") on its behalf.

Key components of the Permit Application are as follows:

- A description of the project and associated air pollutant emission rate increases;
- A discussion of applicable air quality regulations;
- An analysis of Best Available Control Technology (BACT);
- An assessment of compliance with ambient air quality standards and toxic air pollutant (TAP) criteria; and
- A completed SWCAA permit application form.

The air quality impact assessments that follow indicate:

- Predicted maximum concentrations of most criteria air pollutants attributable to the Kalama Energy Center are less than the Significant Impact Levels (SILs) established by USEPA and Ecology. Using conservative assumptions, the 1-hour average NO_2 and SO_2, and the 24-hour average $PM_{2.5}$ concentrations were predicted to exceed the applicable SILs. The SILs represent incremental, project-specific impact levels that the State of Washington accepts as indication that project impacts are insignificant with respect to maintaining compliance with ambient air quality standards established to protect human health and welfare. An exceedance of the SIL does not imply a "significant impact," but indicates that further analysis is required to determine compliance with the ambient standard.
- Predicted 1-hour average NO_2 and SO_2, and 24-hour average $PM_{2.5}$ concentrations were combined with background concentrations derived from monitoring data to assess compliance with the applicable national ambient air quality standards (NAAQS). The analysis indicated that NO_2, SO_2, and $PM_{2.5}$ emissions attributable to the Kalama Energy Center would not cause or contribute to exceedance of the 1-hour average NO_2 and SO_2, and 24-hour average $PM_{2.5}$ ambient standards.
- Predicted concentrations of all toxic air pollutants (TAPs) potentially released from the Kalama Energy Center are either below the applicable Small Quantity Emission Rates (SQERs) or, as demonstrated by an air quality dispersion modeling analysis, the applicable Acceptable Source Impact Levels (ASILs).
- A screening tool utilized by the Federal Land Manager (FLMs) indicated that the proposed project is not likely to impact Air Quality Related Values in nearby Class I areas. A dispersion modeling analysis of a larger project with more air pollutant emissions that had

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been proposed for the same location predicted that concentrations in nearby Class I areas would not exceed the SILs proposed by EPA for Class I areas. Scaling the results of that analysis using the emission rates of the current and past proposals results in even lower predicted concentrations. Based on the results of these screening analyses, the proposed project was assumed to not have the potential to impact nearby Class I areas, and an updated analysis based on the specifics of the currently proposed project is not presented.

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2 Project Description

Energy Northwest proposes to construct and operate the Kalama Energy Center electrical power generating facility. Natural gas would be used to run a combined-cycle combustion turbine generating plant to provide electricity for intermediate-loads and renewable-shaping services. The Kalama Energy Center's maximum net output would be approximately 346 megawatts electrical (MWe) at design (i.e., average ambient) conditions. The facility would be designed to include a net 309 MWe from the combustion turbine and steam turbine, and 37 MWe of additional capacity through duct firing. Whatever the final, installed capacity of the unit, the facility's maximum net output capacity under design conditions will not equal or exceed 350 MWe.

The electric power generating facility would have a combustion turbine-generator (CTG) and a steam turbine generator (STG). The expansion of hot combustion gases inside the combustion turbine creates rotational energy that spins the generator and produces electricity. The hot exhaust gases exiting the CTG pass through a heat recovery steam generator (HRSG), a type of boiler where steam is produced. The resulting steam is piped to a steam turbine that is connected to an electric generator. The expansion of steam inside the steam turbine spins the generator to produce an additional source of electricity.

The total estimated cost of the Kalama Energy Center at the completion of construction would be approximately $400 million, which includes the power plants, and associated equipment. Energy Northwest estimates that the annual operating and maintenance costs would exceed approximately $10 million, including the following:

- Wages and salaries of operation, maintenance, and administrative personnel,
- Procurement of goods and services,
- Insurance, and
- Sales and other state and local taxes.

Process water would be supplied by the Port of Kalama, and would be treated as necessary to meet the Kalama Energy Center's specifications. Process effluent may be discharged through the Port of Kalama's existing discharge line and outfall, which, if necessary, would be upgraded to accommodate the additional demand from the Kalama Energy Center. Potable water would be supplied by the City of Kalama in lines that have already been installed for the site. Sanitary wastewater would be discharged to the Port of Kalama's wastewater treatment plant located to the southeast of the Kalama Energy Center.

The fuel would be natural gas, supplied by a pipeline built and operated by Cascade Natural Gas or Northwest Pipeline GP, which would connect with Northwest Pipeline GP's pipeline east of the site.

Various numeric values are provided throughout this description. These values are a conservative high-end representation of the proposed project, and are used to indicate relative magnitudes or sizes. In addition to some uncertainty related to the size or capacity of the

proposed emission units, all values are subject to rounding, and are therefore not the exact values. More definitive values will be available after detailed design of the Kalama Energy Center is completed, and more exact values after the unit is installed and tested.

2.1 Site Arrangement

The Kalama Energy Center would be located on an approximately 16-acre site in Cowlitz County, Washington. The general location of the project is presented in Figure 2-1. The development would be constructed within the North Port Marine Industrial Park at the Port of Kalama. The development site is located 1,400 feet from the east bank of the Columbia River, and both the Burlington Northern Santa Fe (BNSF) and Union Pacific (UP) joint railway and Interstate 5 (I-5) lie immediately to the east. The property to the south is vacant land, some of which is leased from the Port of Kalama by Air Liquide, which operates a specialty air products facility. To the north is a backwater channel of the Columbia River.

The major pieces of equipment or systems that would comprise the Kalama Energy Center are:

- Combustion Turbine Generator (CTG),
- Steam Turbine Generator (STG),
- Heat Recovery Steam Generator (HRSG) with Duct Burner,
- Auxiliary Boiler,
- Cooling Tower,
- Diesel-Powered Back-Up Generator,
- Diesel-Powered Emergency Fire Pump, and
- Three SF_6 High-Voltage Circuit Breakers.

From a visual perspective, significant on-site structures include:

- Combustion Turbine Generator Building (approximately 110 ft. by 50 ft. by 75 ft. high),
- Steam Turbine Generator Building (approximately 130 ft. by 190 ft. by 67 ft. high),
- Heat Recovery Steam Generator (approximately 170 ft. by 50 ft. by 100 ft. high),
- Six-cell Cooling Tower (approximately 300 feet by 50 feet by 48 feet high),
- Exhaust Stack (approximately 140 feet high by 22 feet in diameter),

Actual dimensions of these structures would not be determined until engineering is completed.

2.2 Air Pollutant Emission Rates

In order to determine the applicability of regulations and the potential air quality impacts associated with a proposed industrial facility such as the Kalama Energy Center, the types and quantities of emitted air pollutants must be identified. Pollutant emission rates are determined by the physical and operational characteristics of the facility. This section describes the manner in which the facility will operate, and how air pollutant emission rates were calculated. Detailed spreadsheets supporting the emission rate calculations are provided in Appendix A.

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2.2.1 Short-term Normal Operation Emission Rates

Power Generation Unit (PGU)

Although a combustion turbine manufacturer has not been formally selected, emission rate estimates are based on those of a Siemens model SGT6-5000F(4) combustion turbine. The combustion turbine is expected to meet the proposed continuous-operation emission limits for each criteria pollutant between 50 percent load and 100 percent load. Turbine operation would be supplemented by duct burner combustion in the HRSG. A schematic drawing of the PGU is presented in Figure 2-2. To evaluate air quality implications of the range of operating conditions, we examine three potential "normal" operating modes:

- 1) 100 percent combustion turbine load with duct burners
- 2) 100 percent combustion turbine load without duct burners
- 3) 50 percent combustion turbine load without duct burners

Table 2-1 presents short-term emission rates for each combustion turbine operating mode; here, as elsewhere in this application, the averaging periods we consider generally correspond to the averaging period applied to that pollutant's ambient standard. Although operation with duct burners typically produces the highest overall facility emission rates, the modeling analyses considered all three operating modes because predicted ground level concentrations are affected by exhaust gas characteristics (flow rate and temperature) as well as emission rates. While the exact equipment performance and exhaust gas conditions will not be known until the unit is installed and tested, design data provided by Siemens for a representative unit at the high end of the possible capacity and emission rate range were used to calculate emission rates and exhaust release characteristics.

NO_X and CO emission rates were calculated using a proposed exhaust concentration limit of 2 parts per million by volume, dry (ppmvd) at 15 percent O_2, based on a 3-hour and 1-hour average, respectively. Energy Northwest has based the SO_2 emission rate on mass balance calculations using the concentration of sulfur in the natural gas, as measured at the Huntingdon pumping station in British Columbia. Recent data reveal daily and annual average concentrations of 2.07 and 1.05 grains sulfur per 100 cubic feet (gr/100 cf) of natural gas, respectively.[1] Particulate matter (PM) and VOC emission rates are based on data provided by Siemens, except that ENVIRON added a sulfate contribution to the PM assuming that 30 percent of the sulfur in the gas was converted to sulfate (however, the SO_2 emission rate was not reduced by 30 percent to account for this conversion; the analysis is conservative in that it effectively "double counts" some sulfur in the fuel). In this section, for any applicability analysis, and for the air quality dispersion modeling analyses, the $PM_{2.5}$ emission rate is assumed to be equal to the PM_{10} emission rate.[2]

1 SO_2 emission factors were based on these values with an added 25 percent margin of safety.
2 The New Source Review transition period, established by the final rule "Implementation of the New Source Review (NSR) Program for Particulate Matter Less Than 2.5 Micrometers ($PM_{2.5}$)" issued by USEPA on May 16, 2008, in which condensable PM emissions could be excluded from modeling analyses, ended on January 1, 2011.

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The PGU also has the potential to emit non-criteria air pollutants that are regulated at the federal level by the CAA Section 112 and at the state level by Ecology under Chapter 173-460 WAC. Some of these pollutants are deemed "hazardous air pollutants" (HAPs) under the CAA Section 112, and some are defined as TAPs under Chapter 173-460 WAC.

Table 2-2 identifies TAPs and HAPs expected to be emitted by the PGU. Combustion turbine emission rates were based on emission factors from Section 3.1 of USEPA's AP-42 emission factor document (Stationary Gas Turbines), while duct burner emission rates were calculated using emission factors in Section 1.4 (Natural Gas Combustion) of AP-42. The ammonia slip emission rate for the PGU is based on a proposed stack concentration permit limit of 5 ppmvd at 15 percent O_2. The sulfuric acid (H_2SO_4) emission rate is based on an assumed 30 percent conversion of SO_2 (the same as the sulfate contribution to the PM_{10} emission rate). Table 2-2 presents the maximum total TAP and HAP emission rates from the combustion turbine under full load operation with duct firing.

Auxiliary Boiler

The auxiliary boiler will combust only natural gas, and is used to generate steam to assist with startup of the combustion turbine. The steam reduces the duration of the startup period for the combustion turbine generator and steam turbine generator. Although the boiler is unlikely to operate concurrent with the combustion turbine following startup, the continuous operation "base load" modeling scenario assumes the boiler is operating at maximum load for the duration of each short-term averaging period. The criteria pollutant emission rates summarized in Table 2-3 are based on the use of ultra-low-NO_X burners to achieve a NO_X exhaust concentration of 9 ppmvd at 3 percent O_2, and good combustion control to achieve a CO exhaust concentration of 50 ppmvd at 3 percent O_2. The SO_2 emission rate is based on a mass balance calculation similar to that discussed for the PGU. PM_{10} and VOC emission rates are based on factors from Section 1.4 of AP-42.

Auxiliary boiler TAP emission rates were calculated based on natural gas-fired boiler emission factors from Section 1.4 of AP-42 and the maximum rated capacity of the boiler (36.5 MMBtu/hr). Maximum annual emission rates were based on an annual capacity factor of 50 percent. Table 2-4 presents the TAP and HAP emission rates for the auxiliary boiler.

Diesel-Powered Back-Up Generator and Emergency Fire Pump

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. Additionally, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection. The engines will meet the emission standards prescribed by 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). Ordinarily, the engines will each operate at most an hour per week for maintenance and testing, and Subpart IIII limits non-emergency operation to 100 hours per year. In the modeling analyses, with the exception of the 1-hour average NO_2 standard compliance analysis, it was assumed that the engines would both operate throughout the short-term averaging periods, even though that would not occur in practice. For the 1-hour average NO_2 standard

compliance analysis, it was assumed that the diesel engines would never be tested at the same time. Annual emission rates are estimated based on 52 hours of operation over the course of a year (i.e., one hour of testing and maintenance per engine, per week). Hourly and annual criteria pollutant emission rates are presented in Tables 2-5 and 2-6, and TAP and HAP emission rates are provided in Tables 2-7 and 2-8.

Cooling Tower

A cooling tower would be installed and operated to condense steam so that the water can be recycled. These cooling towers release water droplets that contain naturally-occurring dissolved solids from the water supply, and are concentrated in the cooling process.

The cooling tower is configured as a set of six cells. The quantity of water released as droplets to the air (the drift rate) is based on 0.0005 percent of the water recirculation rate, and reflects the use of very high efficiency drift eliminators. The total dissolved solids (TDS) content of the drift is the maximum value estimated from local water quality measurement data water concentrated 12 times by the water recirculation cycles. The hourly and annual cooling tower PM emission rates shown in Table 2-9 based on the assumption that water throughput is maximized in all cooling tower cells at all times.

The cooling tower would emit small quantities of TAPs, which would come primarily from the inorganic material found in the makeup water. TAP emission rates were estimated using the Kalama well water analysis, a drift rate of 0.0005 percent of the total cooling water used, and an assumption of continuous operation at 100 percent turbine load with duct firing. Table 2-10 presents the estimated total TAP and HAP emission rates from the cooling tower.

Short-Term Emissions Summary

Short-term maximum criteria pollutant emission rates for normal operation are summarized in Table 2-11. The emission rates presented in this table are based on the maximum operating rates for the combustion turbines (100 percent load with duct firing), cooling tower, auxiliary boiler, and fire water pump. In practice, it is very unlikely that these units would all be running simultaneously at their maximum capacities.

2.2.2 Short-Term Startup/Shutdown Emission Rates

During periods of startup or shutdown, the PGU is expected to emit some pollutants at rates that are higher than during normal operation. Depending upon the pollutant, this is because combustion is not yet optimized or control equipment is not functional. As with automobile engines, combustion turbines emit more carbon monoxide during startup because combustion is optimized for a warm engine and typical loaded conditions (usually 50 percent load or greater). Combustion turbine NO_X emission rates are also higher during startup, in part because the SCR is not effective at low exhaust gas temperatures.

The duration and total quantity of air pollutant emissions from a combustion turbine startup depend on how long it has been shut down prior to the startup. Table 2-12 identifies the duration of a combustion turbine startup event, and the quantity of air pollutants emitted during

the event. Note that once the combustion turbines reach 50 percent load, the SCR and oxidation catalyst will be operational and the combustion turbine emission rates will meet the proposed emission limits.

The Kalama Energy Center is projected to be a "load shaping" facility used in conjunction with an intermittent energy source (e.g., wind power). Because the facility is likely to experience frequent startups and shutdowns, it will employ a design that enables the combustion turbine to start and achieve emissions compliance in a relatively short period of time. Essentially, the design allows a combined-cycle unit to startup in the same manner as a simple-cycle unit.

Startup/shutdown scenario emission rates were calculated using the startup and shutdown durations and emissions in Table 2-12, and the normal operation emission rates in Table 2-1 (100 percent load with duct firing was always assumed for normal operation). A maximum of 730 startups and shutdowns per year, or an average of 2 startups and shutdowns in a 24-hour period, was considered. The worst-case short-term emission rate and scenario was identified for each pollutant and short-term averaging period; the results are presented in Table 2-13.

The calculated worst-case startup/shutdown scenario emission rates indicate that the quantity of, NO_X, CO and VOC emitted during a startup event is greater than during a similar period of normal operation; the quantity of PM emitted during a startup event is comparable to, but slightly less than a similar period of normal operation. Because the quantity of SO_2 emitted depends solely on the quantity of fuel used, the reduced fuel consumption rate during startup and shutdown results in smaller quantities of SO_2 emissions than would be expected over a similar period of normal operation.

The modeled startup and shutdown scenarios all included auxiliary boiler, cooling tower, and emergency diesel engine emissions (i.e., the firewater pump engine and the back-up emergency generator). While it is conceivable that the auxiliary boiler and cooling tower would be operating during startup or shutdown, it is unlikely that either emergency engine would be operated for testing or maintenance during that period.

2.2.3 Annual Emission Rates

Annual emission rates (typically expressed as tons per year or tpy) depend on the number of hours each emission unit operates and the unit's rate of operation during those periods. Table 2-14 presents annual emission rates for two scenarios. Only the PGU emission rates vary between the two scenarios; emission rates associated with the auxiliary boiler, the cooling tower, and the firewater pump are assumed to be the same for both scenarios.

The first scenario assumes the combustion turbine operates every hour of the year in the operating mode with the greatest emission rates; as shown in Table 2-1, this occurs for all pollutants when the CT operates at 100 percent load with duct firing.

The second scenario considers a worst-case potential operating mode in which the PGU is started and shutdown frequently. Because the number and frequency of startups and shutdowns is impossible to predict in advance, worst-case potential emission rates were calculated based on a maximum of 730 startups and shutdowns per year (an average of 2 per

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24-hour period), with an hour of non-operation between each shutdown and startup. Emission rates associated with full load operation with duct firing were assumed to be in effect for all non-startup and non-shutdown periods (i.e., "normal" operation) for the annual startup and shutdown scenario emission rate calculations.

Auxiliary boiler annual emission rates are based on full load operation for 50 percent of the hours in a year (4,380 hours). Although Energy Northwest intends to test the firewater pump engine and the back-up generator only one hour per week each, the annual emission scenario assumes each engine is operated 52 hours per year at its maximum capacity rating. Annual PM_{10} emissions from the cooling towers are based on the assumption that the water flow rate is maximized in each cell every hour of the year. In practice, water flow may be reduced as outdoor temperatures drop or when the combustion turbine load decreases. Consequently, this assumption provides a conservative estimate of cooling tower emissions.

2.2.4 Greenhouse Gas Emission Rates

Greenhouse gases (GHGs) will be emitted by the four proposed emission units that combust fuel: the PGU, the auxiliary boiler, and the diesel engines associated with the back-up generator and the emergency fire pump. Emission rates were calculated for each emission unit using the maximum annual activity (heat input or fuel use) and emission factors for the three GHGs associated with combustion: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). The GHG emission factors were obtained from Tables C-1 and C-2 of the Federal Mandatory GHG Reporting Rule (40 CFR Part 98). Table 2-15 summarizes the GHG emission rate calculations; facility-wide potential to emit is approximately 1,245,000 tons of carbon dioxide equivalent (CO_2e) per year.

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3 Regulatory Review

The proposed project to construct and operate an electrical generation facility is subject to federal, state, and local regulations. The following section discusses the applicable regulations and why certain regulatory programs are not applicable. It should be noted that the project will be located in an area that is in attainment of all applicable federal and state air quality standards.

3.1 Federal Regulations

3.1.1 Prevention of Significant Deterioration (PSD)

The PSD permit process was established by USEPA to ensure that new or expanded major stationary sources that emit criteria pollutants above a significance rate do not cause air quality in areas that currently meet the standards (i.e., attainment areas) to deteriorate significantly. These regulations require the application of BACT, and set PSD increments, which limit the increases in SO_2, NO_2, and PM concentrations that may be produced by a new source. Increments have been established for three land classifications. The most stringent increments apply to Class I areas, which include wilderness areas and national parks.

The Kalama Energy Center is subject to PSD regulations because it has the potential to emit more than 100 tons per year of a regulated pollutant (NO_x and CO, see Table 2-14), and more than 75,000 tons per year of GHGs on a CO_2 e basis (see Table 2-15). As shown in Table 2-14, the maximum potential annual emissions of NO_X, CO, PM_{10}, $PM_{2.5}$, and VOC are over the PSD significant emission rates (SERs), and are therefore subject to PSD review. Compliance with PSD increments is addressed in Section 4 for Class II areas (those deemed able to accommodate normal well-managed industrial growth), and Section 5 for Class I areas. BACT for criteria pollutants (i.e., NO_X, CO, PM, and VOCs) is addressed in Appendix B, and BACT for GHGs is addressed in Appendix C.

An ozone impact analysis is required for new or expanded major stationary sources that are expected to increase either NO_X or VOC emissions by more than 100 tons per year. An analysis of the effect of industrial emissions on ozone formation in the Portland, Oregon and Vancouver, Washington region was conducted by Washington State University (WSU). A summary of that study is provided in Appendix D.

The WSU study simulated a July ozone episode in 2015, and considered two future pollutant emission scenarios. One scenario included emissions from potential future industrial growth in the lower Columbia River; the emission rates of all pollutants, not just ozone precursors, included in the study are considerably less than those attributable to the KEC project. The second scenario did not include any projected future emissions from industries in the lower Columbia River. A comparison of the ozone concentrations calculated for the two scenarios indicated that the assumed industrial emission rate increases would have no effect on the simulated peak 8-hr ozone concentration in the Portland/Vancouver area. The results from this modeling analysis indicate that anticipated emissions increase attributable to KEC would not have a large impact on ozone concentrations in the Portland/Vancouver area, and would not affect the area's ozone maintenance plan.

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3.1.2 Title 4 (Acid Rain) Provisions

Title 4 of the Clean Air Act (CAA) Amendments of 1990 provide a strategy for reducing national emissions of NO_X and SO_2 as part of a comprehensive plan for reducing acid deposition. 40 CFR Part 72 requires fossil fuel-fired combustion turbines larger than 25 MWe, such as the Kalama Energy Center, to monitor flow rate, oxygen, and NO_X and SO_2. Monitoring may take the form of CEMS or calculations based on fuel sulfur monitoring or similar techniques. The requirements for CEMS are similar to those required under the NSPS except that CEMs for sources subject to 40 CFR Part 72 must meet more stringent accuracy limits during annual relative accuracy test audits.

USEPA limits national SO_2 emissions attributable to power generation by capping the number of SO_2 'allowances' distributed each year. An 'allowance' corresponds to one ton of allowable SO_2 emissions. USEPA grants some older facilities a number of allowances each year; however sources built after 1996 must purchase all of their requisite allowances. Each March 1st, all sources subject to the Acid Rain program must possess one allowance for each ton of SO_2 emitted from that facility during the previous calendar year. Each source must use its monitoring data to calculate its required number of allowances.

3.1.3 Title V Air Operating Permit

The Title V air operating permit program does not establish new emissions limits but may add new monitoring, record-keeping, and reporting requirements to those established during the pre-construction permitting process. The Kalama Energy Center will be required to obtain a Title V air operating permit as required under WAC 173-401-300, but the Title V permit is not required for the project to commence construction. A Title V permit application must be filed within 12 months of the project commencing operation.

3.1.4 New Source Performance Standards

USEPA has established performance standards for a number of air pollution sources in 40 Code of Federal Regulation (CFR) Part 60. These New Source Performance Standards (NSPS) represent a minimum level of control that is required on a new source. This section identifies those NSPS that apply to the Kalama Energy Center's emission units, including 40 CFR 60 Subparts A, Dc, IIII, and KKKK. In practice, the emission limits imposed by NSPS are rarely governing for new sources because the emission limits deemed BACT are virtually always lower.

<u>Subpart A, General Provisions</u>

Subpart A identifies a number of monitoring, record-keeping, and notification requirements that generally apply to all NSPS subparts. Subpart A specifies that performance (source) tests must be conducted within 60 days of achieving maximum production rate at which the source would be operated, but not later than 180 days after initial startup.

Consistent with NSPS requirements, Energy Northwest would notify SWCAA of the anticipated initial start-up date, the actual start-up date, any changes in the facility that affect emissions, compliance sources tests, and certification tests for continuous emission monitors. Energy Northwest would also maintain records of start-ups and shutdowns, malfunctions of control

equipment or periods of excess emissions if they occur, and periods when continuous emission monitoring equipment is inoperative.

Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that combust more than 10 million British thermal units per hour (MMBtu/hr) and commenced construction, modification or reconstruction after February 18, 2005. The combustion turbine proposed for the Kalama Energy Center meets these criteria, and will therefore be subject to the requirements of Subpart KKKK. Subpart KKKK limits NO_X exhaust concentration to 15 ppm, which is significantly higher than the proposed NO_X exhaust concentration (2 ppmvd at 15 percent O_2). Subpart KKKK limits SO_2 emissions to 0.90 lb/MWe-hr, or 612 lb/hr for the proposed combustion turbines at maximum operating conditions; estimated SO_2 emissions based on the local gas supply (Sumas, WA) are expected to be no more than 9.0 pounds per hour.

Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

Subpart Dc applies to steam generating units that commence construction, modification, or reconstruction after June 9, 1989, and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc would apply to the auxiliary boiler because it would be rated at approximately 40 MMBtu/hr.

Because the auxiliary boiler would be fired solely with natural gas, only the record-keeping and reporting provisions of Subpart Dc apply. These requirements include maintaining records of daily fuel use, occurrence and duration of startup, shutdown, or malfunction, malfunction of control equipment, and periods when a continuous monitoring system or monitoring device is inoperative. These records must be maintained for two years.

Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII applies to the diesel-fired firewater pump engine and the back-up diesel generator proposed for the Kalama Energy Center that would be used to suppress fires when grid power is not available to operate the electric firewater pump. Engine manufacturers are required to certify engines for prescribed NO_X, PM, CO, and VOC emission standards. Engine operators are required to follow the manufacturer's operation and maintenance instructions. Emergency engines such as the firewater pump engine are limited to 100 hours per year of non-emergency operation (e.g., maintenance and testing).

3.1.5 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Title III of the 1990 Clean Air Act Amendments requires EPA to regulate the emissions of a total of 189 HAPs from all stationary and mobile sources. EPA does this by specific industry categories so that it can tailor the controls to the major sources of emissions and the HAPs of concern from that industry. The rules promulgated under Title III generally specify the Maximum

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Achievable Control Technology (MACT) that must be applied for a given industry category. Consequently, these rules are often called MACT standards.

MACT standards are industry-specific technology-based standards designed to reduce HAP emissions. These standards can require facility owners/operators to meet emission limits, install emission control technologies, monitor emissions and/or operating parameters, and use specified work practices. In addition, the standards typically include recordkeeping and reporting provisions. MACT standards are codified in 40 CFR Part 63. NESHAP standards are codified in 40 CFR Part 61.

Sources are subject to MACT rules only if they have a potential to emit more than 10 tons per year of a single HAP or more than 25 tons per year of all HAPs combined. Table 3-1 presents a summary of estimated maximum potential annual HAP emissions from the Kalama Energy Center. Facility-wide HAP emissions are 7.6 tons per year, which is less than the MACT program major source threshold of 25 tons per year. Hexane is the HAP emitted in the greatest quantity; at 3.3 tons per year, its emission rate is also less than the applicability criterion of 10 tons per year. Based on these emission rate calculations, the facility would not be subject to the MACT program.

3.2 State and Local Emission Limits

Emission limits are established by the BACT review process. The BACT analysis identifies pollutant-specific alternatives for emission control, as well as the advantages and disadvantages of each alternative. The determination of which control technologies best protect ambient air quality is made on a case-by-case basis and considers collateral economic, energy and environmental impacts.

Chapter 173-460 WAC requires that BACT also be employed to control emissions of TAPs (i.e., T-BACT). Generally, the same technologies or operations that reduce criteria pollutants also reduce TAPs. For example, the use of gaseous fuels instead of solid fuels reduces emissions of most criteria and TAPs. The use of combustion controls to optimize combustion also reduces both criteria pollutants and TAPs. The BACT analysis included as Appendix B of the Application identifies the use of good combustion practices and gas cleaning as the BACT for TAPs.

General standards for maximum emissions for air pollution sources in Washington are outlined in WAC 173-400-040. This section limits visible emissions to 20 percent opacity except for 3 minutes per hour; controls nuisance particulate fallout, fugitive dust, and odors; and limits SO_2 emissions to no more than 1,000 ppm (hourly average, 7 percent O_2, dry basis). WAC 173-400-050 identifies emission standards for combustion and incinerator units, and limits particulate matter emissions to 0.1 grains per dry standard cubic foot at 7 percent O_2.

SWCAA regulations mirror Ecology's emission limits for new sources. The SWCAA regulation's opacity standard limits the plume to 20 percent opacity except for 3 minutes of any hour. Particulate matter emissions are limited to 0.1 grains per dry standard cubic foot. Sulfur emissions, calculated as SO_2, are limited to 1,000 ppm.

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The maximum PM_{10} emission rate from the PGU would be (at most) about 17.8 lb/hr. Given a flow rate of approximately 1 to 1.5 million dry standard cubic feet per minute (dscfm) from the PGU (depending upon whether or not duct firing is occurring), this emission rate corresponds to grain loadings of less than 0.01 grains/dry standard cubic foot (gr/dscf). Thus, the anticipated grain loading is less than 10 percent of the 0.1 gr/dscf allowed by the state regulation. Plume opacity associated with grain loadings this low would be less than 5 percent, which is well below the allowed 20 percent. The anticipated SO_2 concentration would also be well below the state limit of 1,000 ppm.

3.2.1 Notice of Construction Application and Order of Approval

Washington State law (WAC 173-400-110) requires that a notice of construction (NOC) application be filed by the owner or operator of a proposed new air contaminant source, and an order of approval (OA) must be issued by the permitting authority before construction can commence. SWCAA maintains a similar regulation for new or modified sources in its jurisdiction, where the NOC is referred to as an Air Discharge Permit Application, and the OA is referred to as an Air Discharge Permit (ADP). The ADP application provides a description of the facility and an inventory of pollutant emissions and controls. The reviewing agency, in this case SWCAA, considers whether BACT has been employed and evaluates ambient concentrations resulting from these emissions to ensure compliance with ambient air quality standards. Compliance with ambient standards is addressed in Section 4. BACT for NO_X, CO, PM, SO_2, and VOCs is addressed in Appendix B.

3.2.2 Toxic Air Pollutants (TAPs)

WAC 173-460 governs air pollutants identified as TAPs in Washington. Emissions of TAPs from industrial sources such as the Kalama Energy Center that exceed prescribed Small Quantity Emission Rates (SQERs) must be evaluated with dispersion models to determine compliance with ambient air quality criteria (Acceptable Source Impact Levels, or ASILs). However, WAC 173-460 was revised in June 2009, and SWCAA has not adopted the revisions. Therefore, the pre-June-2009 WAC 173-460 rules are still in force in areas under SWCAA's jurisdiction. Table 3-2 compares facility-wide TAP emission rates with the applicable SQERs. TAPs emitted at rates exceeding the SQERs have been evaluated with the AERMOD dispersion model; the results of that evaluation, which predicted that no TAP will exceed the applicable ASIL, are presented in Section 4 of this document.[3]

Per SWCAA Rule 400-109(3)(ii)(A) emergency service internal combustion engines are exempt from any toxic air pollutant review required as part of the ADP application. As a result, diesel fire pump engine and back-up diesel generator emission rates were not calculated, and those emission units were not included in the Tier I TAP analysis (i.e., comparing facility-wide TAP emissions to the SQERs and modeling TAP emissions to determine ambient concentrations for comparison to the ASILs).

3 Although not required by SWCAA, a parallel TAPs analysis using the SQERs and ASILs provided in the new WAC 173-460-150 (effective June 20, 2009) was conducted. The dispersion modeling analysis predicted that none of the TAPs exceeding the applicable SQER would exceed the applicable ASIL.

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Although TAP emissions are, as stated above, under SWCAA's jurisdiction, facility-wide TAP emissions were compared to the applicable SQERs in the post-revision WAC 173-460. The results of that comparison are presented in Table 3-3. As for the pre-June-2009 TAP regulations, TAPs emitted at rates exceeding the post-June-2009 SQERs were evaluated with the AERMOD dispersion model. The results of that analysis, which predicted that no TAP will exceed the applicable post-June-2009 ASIL, are also presented in Section 4 of this document.

Before and after the June 2009 revision, WAC 173-460 requires that all new or modified emission units that trigger the need to submit an NOC must employ BACT to limit TAP emissions. BACT for TAPs (tBACT) is addressed in Appendix B.

3.2.3 Greenhouse Gas Emission Performance Standard

Although the Kalama Energy Center is not expected to operate as a baseload generation facility, it is conceivable that it could operate in such a capacity depending upon the demands of the energy market. As a result, the facility is potentially subject to the requirements of Part II of WAC 173-407, which implements a Greenhouse Gas Emission Performance Standard consistent with the requirements of RCW 80.80. The standard requires that baseload electric generation facilities not emit regulated greenhouse gases at a rate greater than 1,100 pounds of CO_2 equivalent per megawatt-hour (lb CO_2e/MW-hr), on an annual average basis. The PGU at the Kalama Energy Center is expected to emit greenhouse gases (i.e., CO_2, CH_4, and N_2O) at a maximum short-term average rate of 795 lb CO_2e/MW-hr, which is less than the established annual average limit (see Appendix E for calculation details). Therefore, the Kalama Energy Center is expected to comply with the requirements of RCW 80.80.

3.2.4 Carbon Dioxide Mitigation

Because the facility is potentially subject to the Greenhouse Gas Emission Performance Standard discussed in the previous section, and will have a station generating capability greater than 25 MWe, but less than 350 MWe, it is subject to the requirements of Part 1 of WAC 173-407, which implements a carbon dioxide (CO_2) mitigation program consistent with the requirements of RCW 80.70. If the PGU operated at full capacity every hour of the year at design conditions, the auxiliary boiler operated at 50 percent capacity and both diesel fired emergency engines operated for 100 hours per year, CO_2 emissions would be 1,091,246 tonnes (i.e., metric tons) per year (see Appendix E for calculation details). The mitigation quantity outlined in the regulation considers 30 years of operation with a capacity factor of 60 percent, or 17.95 million tonnes. WAC 173-407 requires the Kalama Energy Center to mitigate 20 percent of the mitigation quantity, or 3.59 million tonnes.

Energy Northwest has chosen the "monetary path" outlined in WAC 173-407-060(3) for mitigation. At the initial mitigation rate of $1.60 per metric ton of carbon dioxide provided in the regulation, the required payment would be approximately $5.75 million. Energy Northwest will either:

(a) Provide SWCAA with proof of payment to a qualifying organization of the total sum of $5,745,065, no later than one hundred twenty days after the start of commercial operation, or

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(b) Provide SWCAA with proof of payment to a qualifying organization of $1,149,013 no later than one hundred twenty days after the start of commercial operation, and provide SWCAA with proof of payment to a qualifying organization of the amount required under WAC 173-407-060(3) no later than the anniversary of the initial payment on each of the following four years.

3.3 State Environmental Protection Act

Because construction of the power generation station requires an ADP from SWCAA, the requirements of Washington's State Environmental Protection Act (SEPA) must be satisfied. The lead agency for the SEPA process is Cowlitz County. A SEPA checklist is currently being prepared and will be submitted to Cowlitz County.

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4 Local Air Quality Impact Assessment

An ADP may not be issued unless the proposed new source or modification can demonstrate that the allowable emissions will not cause or contribute to violation of any ambient air quality standard or increment. This is typically accomplished using air quality dispersion modeling to predict ambient concentrations. This section discusses the methodology used to develop near-field modeling used to predict pollutant concentrations attributable to the Kalama Energy Center emissions in the areas surrounding the proposed facility.

4.1 Model Selection

Regulatory modeling techniques were reviewed to select the most appropriate air quality dispersion model to simulate dispersion of air pollutants emitted by the Kalama Energy Center. The selection of a modeling tool is influenced by the potential for exhaust plumes from point sources to be influenced by nearby on-site structures and to impact complex terrain. The terrain at and immediately surrounding the facility, as well as in the northwest and south portions of the modeling domain, is relatively flat, however, intermediate and complex terrain exists in most of the eastern and southwestern portions of the domain. The heights of proposed and existing structures, and the proposed cogeneration unit stack height, suggests that there is the potential for exhaust plume downwash to occur.

AERMOD, the preferred model in the USEPA's "Guideline on Air Quality Models" (codified as Appendix W to 40 CFR Part 51, hereafter referred to as the "Guideline"), was selected for the modeling analysis primarily because it is the most up-to-date dispersion model currently available. Additionally, the modeling domain and source configuration suggested the potential for exhaust plume downwash and plume impacts on intermediate and complex terrain.

4.2 Modeling Procedures

AERMOD was applied to both criteria pollutant and TAP emissions using the regulatory defaults in addition to the options and data discussed in this section. Electronic copies of the modeling input and output files are provided on the compact disc in Appendix F.

4.2.1 Model Setup and Application

The most recent version of AERMOD (Version 11103) was applied with the default options for dispersion that depend on local meteorological data, regional upper air data, and the local physical characteristics of land use surrounding the facility. AERMOD contains several options for urban dispersion that were not selected for these analyses. The facility is located near, Kalama, Washington, and the majority of the study domain is agricultural land, rangeland or forest. The effects of surface roughness and other physical characteristics associated with the types of land use in the modeling domain were included in the analysis as part of the meteorological database, described in Section 4.2.5.

4.2.2 Averaging Periods

Criteria and toxic air pollutant concentrations predicted by the model were averaged over short-term (1-, 3-, 8-, and 24-hour) and annual averaging periods as required by the applicable ambient criteria for each modeled pollutant.

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4.2.3 Chemical Transformations

The Plume Volume Molar Ratio Method (PVMRM) option in AERMOD was used to assess compliance with the 1-hour NO_2 NAAQS, to calculate the hourly conversion rate of NO_X to NO_2. The PVMRM method requires hourly ozone monitoring data that limits the NO to NO_2 conversion. In this case, ozone monitoring data collected at the Mt. View High School monitoring station in Vancouver, WA during the same period as the meteorological data employed in the modeling (i.e., January 1 to December 31, 1995) were used. For off-season periods when that ozone monitor was not operating, the maximum ozone concentration monitored at the Mt. Rainier – Paradise monitoring station during the winter or 1995 was used (38 ppb). An in-stack NO_2/NO_X ratio of 0.15 was used, along with an equilibrium NO_2/NO_X ratio of 0.90.

Compliance with the annual average NO_2 standards was assessed assuming 75 percent of NO in the exhaust was converted to NO_2.

4.2.4 Elevation Data and Receptor Network

Terrain elevations for preliminary receptor locations and emission sources were prepared using 1/3rd arc-second National Elevation Dataset (NED) data developed by the United States Geological Survey (USGS), and available on the internet from the USGS Seamless Data Server.[4] These data have a horizontal spatial resolution of 10 meters (m). Terrain heights surrounding the facility indicate that some of the receptors used in the simulations were located in intermediate or complex terrain (above stack or plume height). The terrain data preprocessor AERMAP (version 11103) was used to prepare the date for input to AERMOD.

For the analysis, the four nested grids were used to model the Kalama Energy Center, with the grid closest to the proposed facility having the closest spacing (25 meters or 82 feet), the next closest with 50-meter (164-foot) spacing, then a 200-meter (656-foot) grid, and, finally, an outer grid with receptors every 500 meters (1,640 feet). Also, receptors were placed every 25 meters (82 feet) along the property boundary. The general location of the modeling domain is shown in Figure 2-1, and the receptor locations are shown in Figure 4-1.

4.2.5 Meteorological Data

A meteorological database was constructed using the AERMET meteorological data preprocessor (version 11059) and available surface and upper air data. A survey of available meteorological data was conducted for use in the simulations. Two possible surface meteorological datasets from the National Weather Service (NWS) were identified that could be used in the dispersion modeling analysis: meteorological data collected at Longview Airport approximately 9 km north-northwest of the proposed facility, or data collected at Portland International Airport, which is approximately 55 km to the south-southeast.

A meteorological station operated by TRC Consultants, Inc for Noveon Chemical (formerly Kalama Chemical and BF Goodrich), and located approximately 3 km south-southeast of the

4 http://seamless.usgs.gov/index.php

proposed facility, collects hourly wind speed, wind direction, solar radiation, temperature, vertical differential temperature (delta-T), and lateral wind turbulence (sigma-theta, or σθ).[5]

A 1995-calendar-year meteorological data set based on surface observations from Noveon Chemical was approved by Ecology for use in dispersion modeling analyses for projects previously proposed at the same site. The station is located within the same portion of the Columbia River valley as the proposed facility, and collected data specifically for PSD permit applications. The sensors and audit procedures employed meet USEPA requirements for meteorological data to be used in support of PSD permit applications, which exceeds the requirements for data used in support of a minor source permit application. The Noveon station includes parameters required by the latest regulatory dispersion model (AERMOD), including sigma theta, which is used to estimate lateral dispersion. The 1995 Noveon dataset has a 100 percent data recovery for all parameters; no "backup" data were used from either the Longview or the Portland airports.

Figure 4-2 shows a wind rose constructed from the 1995 meteorological database. As shown in the figure, the winds are bimodal, following the general north-south orientation of this portion of the Columbia River Valley. The average wind velocity for 1995 was 2.7 meters per second (m/s), and periods of calm wind are rare, occurring for less than 1 percent of the observations. Light winds tend to come up the valley from the north, while the highest wind velocities are from the south and southwest. The winds in the Noveon dataset are quite different from those observed at low-level stations such as those located at Longview or Portland airports, and reflect the influence of the local topography.

Additional meteorological variables and geophysical parameters are required by the dispersion modeling analysis to estimate the surface energy fluxes and construct boundary layer profiles. Surface characteristics including the surface roughness length, albedo, and Bowen ratio were determined for the area surrounding the Noveon meteorological station using the AERMET surface characteristic preprocessor, AERSURFACE (version 08009), and the USGS 1992 National Land Cover (NLCD92) land use data set.[6] The NLCD92 data set used in the analysis has a 30 m mesh size and 21 land use categories. Seasonal surface parameters were determined using AERSURFACE according to the EPA's guidance,[7] and are summarized in Table 4-1.

4.2.6 Emission Source Release Parameters

Figure 4-3 shows the locations of emission sources included in the modeling analysis, as well as significant structures that could potentially influence emissions from the point sources. A summary of the release parameters used to represent the point sources in the simulations is presented in Table 4-2.

5 TRC Environmental Consultants, 1996. Meteorological Data Report, Kalama, Washington, Annual 1995. TRC, 11 Inverness Drive East, Englewood, CO 80112, TRC Project 16826-01, April 25, 1996
6 The USGS NLCD92 data set is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.
7 The AERMOD Implementation Guide (EPA, 2008) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

In addition to release parameters, the building dimensions and facility configuration were provided to AERMOD to assess potential downwash effects. Wind-direction-specific building profiles were prepared for the model using USEPA's Building Profile Input Program for the PRIME algorithm (BPIP-PRIME). The facility layout and building elevations provided by the Kalama Energy Center were used to prepare data for BPIP-PRIME, which provides the necessary input data for AERMOD. Figure 4-3 shows the configuration of significant structures that were used to develop the BPIP-PRIME input files, and Table 4-3 presents the heights of the significant structures included in the simulations.

Based on the site layout and the structure heights, BPIP-PRIME determined that all proposed stacks are less than good engineering practice (GEP) height, and therefore have the potential to be influenced by downwash effects from nearby structures. All necessary information provided by BPIP-PRIME was included in the modeling simulations to reflect these effects.

4.3 Air Quality Impact Analysis Results

To evaluate the potential ambient air pollutant concentrations (i.e., impacts on air quality) attributable to the Kalama Energy Center, the emission rates associated with the three operating scenarios described in Section 3 (i.e., 100 percent load with duct firing, 100 percent load, and 50 percent load) were applied in the dispersion modeling analyses.

Table 4-4 summarizes the maximum concentrations predicted by the modeling simulations, and compares them to both the applicable monitoring de minimis concentrations and the Significant Impact Levels (SILs) established in WAC 173-400-113(3). The SILs represent incremental, project-specific impact levels that the State of Washington accepts as insignificant with respect to maintaining compliance with the NAAQS and Washington ambient air quality standards (WAAQS). Oregon ambient air quality standards (OAAQS) are no more stringent than the corresponding NAAQS and WAAQS.

As shown in Table 4-4, all but three of the predicted criteria pollutant concentrations did not exceed the corresponding SILs; 1-hour average NO_2 and SO_2, and 24-hour average $PM_{2.5}$ were the exceptions. None of the monitoring de minimis concentrations were exceeded. As shown in Table 4-5, which summarizes the 1-hour average NO_2 and SO_2, and 24-hour average $PM_{2.5}$ NAAQS compliance assessment, indicates that the modeling analysis predicts that none of the corresponding ambient standards would be exceeded.

Tables 4-6 and 4-7 present, respectively, the results of the TAP modeling analyses for the pre- and post June 2009 ASILs. As shown in these tables, the simulations demonstrated that emissions attributable to the Kalama Energy Center comply with all applicable ASILs.

4.4 Startup Analysis

To demonstrate that neither short-term nor annual ambient air quality standards will be exceeded as a result of starting up or shutting down the PGU, modeling simulations were developed using the short-term and annual startup scenario emission rates described in Section 2. AERMOD was applied using the methodology developed for the normal operating scenario simulations, though only the 50 percent load stack parameters were included for the PGU to reflect the poor dispersion characteristics that are likely present during startup and

shutdown. It should be noted, however, that PGU startup and shutdown periods are relatively brief, and emissions during the "normal operation" portions included in each averaging period scenario would actually experience more favorable dispersion characteristics.

The only pollutants expected to be emitted in greater quantities during startup, when compared to normal operation at partial load, are CO, NO_2, and VOCs. Nevertheless, all pollutants (except VOCs, which has no associated ambient standards) were included in the modeling simulations. Table 4-8 presents a summary of the results of the startup simulation, and indicates that only the 1-hour average NO_2 and 24-hour average $PM_{2.5}$ SILs are predicted to be exceeded. As for normal operation, the same background values were added to the 1-hour average NO_2 and 24-hour average $PM_{2.5}$ concentrations predicted by the model to assess compliance with the corresponding NAAQS. Table 4-9 summarizes the results of those calculations, and indicates that the applicable standards will not be exceeded.

It should be noted that, although no more than 2 startups and shutdowns in a 24-hour period were considered for pollutants with 24-hour ambient standards (i.e., PM_{10}, $PM_{2.5}$, and SO_2), additional startups and shutdowns within a 24-hour periods would tend decrease total emissions, and, therefore, average hourly emission rates, during the 24-hour averaging period. As noted above, the only pollutants with associated ambient standards that exhibit emission increases by increasing the number of startups and shutdowns are CO and NO_2, and the associated ambient standards are averaged over periods shorter than 24 hours. As a result, a daily, or 24-hour period, limit on startups and shutdowns would not serve to protect any ambient standards.

It would not be physically possible to startup and shutdown the PGU more than once in a 1-hour period, so the 1-hour average NO_2 and CO ambient standards are protected by the physical limitations associated with startups and shutdowns. The hourly average emission rate included in the modeling simulations to predict 8-hour average CO concentrations was based on 2 startups (1 "cold" and 1 "hot") and 2 shutdowns with 1 hour of non-operation and 4.7 hours of operation at full load with duct firing. It is unlikely that the PGU would ever be started more than 3 times in an 8-hour period, but, based on the 8-hour average CO concentrations predicted by the modeling simulations, it is likely that, if it were to occur, compliance with the 8-hour average CO standard would be predicted. Based on the short-term startup and shutdown emission rate calculations and the ambient concentrations predicted by the modeling simulations, no short-term restrictions on the number of startups and shutdowns is warranted to ensure that ambient standards are protected.

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5 Class I Air Quality Impacts and Air Quality Related Values Analyses

As stated in the previous section, new sources or modifications must demonstrate that the proposed allowable emission increases associated with the project will not cause or contribute to violation of any ambient air quality standard or increment. This requirement extends to Class I areas, which include National Parks and Wilderness Areas, which, as discussed in Section 3.1.1, have more stringent PSD increments than other areas. In addition PSD regulations require analysis of potential impacts to air quality related values (AQRVs) of concern (i.e., visibility, soil, flora, fauna, and aquatic resources) in Class I areas within 100 km (62.1 miles) of the proposed site from pollutants emitted by the project that are subject to PSD review. However, for most applications the FLMs (e.g., National Park Service, U.S. Forest Service) request analyses of AQRV impacts for additional Class I areas within 200 km (124 miles) of the site. There are also PSD increments associated with Class I areas.

The locations of the proposed project and all nearby Class I areas are shown in Figure 5-1. The Mt. Adams Wilderness Area is the Class I area nearest to the proposed facility, approximately 95 km (59 miles) to the east. As shown in Table 5-1, there are seven Class I areas within 200 km. Although not a Class I area, Ecology and the FLMs typically request that the Columbia River Gorge National Scenic Area (CRGNSA) be included in AQRV analyses for informational purposes.

In November 2010, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) issued a revision of the Phase I report that provides guidance and recommendations for how AQRV analyses should be conducted. That report describes screening criteria, initially developed by USEPA and modified by the FLMs, that would exempt a source from conducting any further AQRV impact analysis based on annual emission rates and distance from a Class I area.

The status of a proposed new source or modification with respect to these criteria is determined by a calculated factor, often referred to as "Q/D". Q/D is calculated by dividing the total combined project emission increases of NO_X, SO_2, PM_{10}, and sulfuric acid (H_2SO_4), in tons per year (the "Q" in Q/D), by the distance to each Class I area, in kilometers (the "D" in Q/D). The FLMs consider a proposed source located more than 50 km from any Class I area to have negligible impacts with respect to Class I AQRVs if the Q/D factor is 10 or less. As shown in Table 5-1, none of the Class I areas are within 50 km of KEC.

A Q/D screening analysis was developed for the proposed project using the facility's expected potential future emissions (Potential to Emit – or "PTE"). As prescribed by the screening methodology, the maximum facility-wide[8] 24-hour average hourly emission rates for each pollutant of interest (NO_X, SO_2, PM_{10}, and H_2SO_4) were converted to tons per year by multiplying

8 Although the auxiliary boiler, emergency generator engine, and fire pump engine will not operate throughout the year, the maximum daily emissions for those sources were projected to an entire year to provide a conservative analysis.

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by 8,760 hr/yr and dividing by 2,000 lb/ton, and summed. Because the frequency of startups and duration of operation is indeterminate at this point, two Q/D factors were calculated for each Class I area: one assuming continuous operation throughout the year, and one assuming the worst-case 24-hour emission rate incorporating one or more startups for each pollutant (i.e., regardless of whether the worst-case scenario for a given pollutant conflicts with that of another). Table 5-1 summarizes the results of both Q/D analyses: the maximum continuous operation Q/D factor for a Class I area was 2.6 for the Mt. Adams Wilderness Area, and the maximum worst-case Q/D factor was 3.3 for the same area. Although not a Class I area, the CRGNSA was included in the analyses; the maximum normal operation Q/D was 4.0, and the maximum worst-case Q/D was 5.1. All of these values are less than 10, and, therefore, an AQRV analysis is not required by the FLMs.

The AQRV screening method outlined above does not have any bearing on the PSD program requirement to assess compliance with the Class I increment for pollutants that increase by more than the PSD significant emission rates (SERs). As shown in Table 2-12, NO_X, PM_{10}, $PM_{2.5}$, and SO_2 exceed the PSD SERs. (The maximum annual CO and VOC emission rates also exceed the PSD SER, but PSD increments have not been established for these pollutants.) However, based on the lack of impacts predicted by the Class I analysis presented in the 2006 permit application for a larger project proposed for the same location, as well as the Q/D analysis presented above, Ecology has agreed that a Class I PSD increment analysis is not necessary, and none is presented.

In 2006, an application for Site Certification was submitted to the Washington Energy Facility Site Evaluation Council (EFSEC) for a 600 MW Integrated Gasification Combined Cycle (IGCC) power generation facility to be called the Pacific Mountain Energy Center (PMEC). Tables 5-2, and 5-3 summarize the emission units and associated normal operation 24-hour average emission rates for PMEC, KEC. Table 5-4 compares the two projects, dividing KEC emission rates by PMEC emission rates for each emission unit type, as well as for the entire facility. Tables 5-5, 5-6, and 5-7 provide the analogous information (i.e., KEC, PMEC, and KEC divided by PMEC) for operations affected by startup, and Tables 5-8, 5-9, and 5-10 for the worst-case annual average emissions. As shown in the tables, KEC emissions are generally about third to a quarter of those of PMEC. In addition to producing less power (246 MW for KEC versus 600 MW for PMEC), KEC does not feature all of the same emission unit categories (e.g., tank vent oxidizer and flare) nor quantities (e.g., one combustion turbine for KC versus two for PMEC). Nevertheless, the exhaust release characteristics for emission unit categories that the two projects do have in common are similar, comparing Table 5-11 (PMEC emission units) and Table 4-2 (KEC emission units).

Although scaling predicted impacts using emission rate ratios is not a robust method for predicting impacts, it is inevitable that, because of the similar location and emission unit characteristics, the results of the Class I analysis developed for PMEC would be used to assess potential Class I impacts attributable to KEC. Using the emission rates summarized in the aforementioned tables, the maximum Class I area concentrations predicted for PMEC (Table 5-12) were scaled to obtain estimated maximum Class I area concentrations attributable to KEC (Table 5-13). As expected, because PMEC was predicted to not significantly impact any Class I area, and KEC emissions are substantially less than those proposed for PMEC, none of the

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estimated impacts attributable to KEC were predicted to exceed the SILs proposed by USEPA or those recommended by the FLMs.

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6 Additional Impacts Analyses

6.1 Class II Area Growth

During construction, the demand for skilled crafts people would increase. This demand would be temporary (less than two years).

KEC will consume natural gas, delivered by pipeline, to produce electricity, which will be delivered by electrical transmission lines. Consequently, the facility will not require a large workforce to provide raw materials to the facility or to transport product from the facility. However, operation of the facility will require a work force of approximately 20 to 22 people. By comparison, the neighboring Steelscape and Noveon Kalama facilities employ approximately 305 and 158 people, respectively. Energy Northwest does not expect KEC to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

6.2 Class II Visibility

On a large spatial scale, visibility is typically evaluated as “regional haze.” The PSD permit application addressed regional haze in the discussion of Class I air quality related values. On a local scale, “visibility” is usually evaluated by considering perceptibility of a plume from a stack or cooling tower.

The combustion turbines will be the largest source of emissions at the facility. Although state and local regulations subject the exhaust plume from combustion turbines (and other on-site sources) to a 20 percent opacity limit, emissions from combustion turbines are typically less than 5 percent and are rarely visible.

However, KEC will include a six-cell cooling tower to handle waste heat from the power island. The cooling tower cells will produce visible water vapor clouds that vary in size depending on meteorology and operational factors. Cooling tower plumes are most visible when the ambient air is nearly saturated with water.

The project previously proposed for the site, Pacific Mountain Energy Center (PMEC) provided an analysis of potential cooling tower impacts using the Seasonal/Annual Cooling Tower Impact (SACTI, Version 11-01-90) model and meteorological data from Noveon Chemical. These meteorological data were also used in the air quality dispersion modeling assessment for both PMEC and KEC. It should be noted that PEMC included three cooling towers, while KEC includes one. The conclusions drawn from that modeling analysis are as follows:

- It is unlikely plume induced ground-level fogging/icing will occur significantly on nearby roads from either cooling tower
- Due to the moist climate of the region, long condensed plumes may result during periods of elevated relative humidity. However, such condensed plumes usually occur during conditions of already poor or obscured visibility. During daytime hours when local weather does not obscure the plume, typical condensed plume lengths are less than 40 m and heights less than 30 m for both cooling towers.

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6.3 Soils and Vegetation

Air quality permitting regulations require proponents of new major sources to provide an evaluation of potential impacts to air quality related values. These include impacts to visibility, soils and vegetation. In virtually all cases, the impact analysis for soils and vegetation has focused on impacts to Class I areas. The focus on Class I areas occurs because these areas often include sensitive environments, such as alpine lakes and streams, high-elevation vegetation, and sensitive habitat for threatened or endangered species. As discussed in Section 5 of the PSD permit application submitted for KEC, potential impacts to soils and vegetation in Class I areas are judged to be insignificant based on screening criteria used by Federal Land Managers.

For Class II areas, the concern for soil and vegetation impacts is different from that of Class I areas. Generally it is not a sensitive habitat that is of concern, but rather the economic well-being of the soils and vegetation for the area. Impacts to agriculture or forestry are the major concerns. There have been instances elsewhere in the U.S. where high levels of sulfur emissions from coal fired power plants, or smelters have caused localized impacts to vegetation and soils near the facility. In fact, the primary National Ambient Air Quality Standards (NAAQS) were established to protect the public health and welfare, and secondary NAAQS were identified specifically to protect ecological properties such as soils and vegetation. The air quality assessment provided in the submitted PSD permit application indicates that the NAAQS would be protected, and that the incremental increases in ambient pollutant concentrations would be very small, suggesting that deposition of nitrogen and sulfur compounds to soils and vegetation would also be small.

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Tables

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Table 2-1 Power Generation Unit (PGU) Criteria Pollutant Short-Term Emission Rates

Operating Mode	Maximum Emission Rate[1] (lb/hr)					
	NO_x[2]	CO[2]	SO_2[3]	H_2SO_4[4]	$PM_{10}/PM_{2.5}$[5]	VOC[6]
100% load with duct firing	18.5	11.3	18.2	2.58	17.1	3.22
100% load, without duct firing	16.5	10.0	16.2	2.29	15.2	2.86
50% load	10.4	6.33	10.2	1.45	9.61	1.81
Maximum	18.5	11.3	18.2	2.58	17.1	3.22

1 Based on the maximum emission rate scenario for each pollutant, which is 100 percent load with duct firing and the lowest rated ambient air temperature (10 °F)
2 Based on 2 ppmvd at 15 percent O_2
3 Based on a maximum hourly natural gas sulfur content of 0.557 grains per pound (which is based on a mass per unit volume of 2.59 gr/100cf and a natural gas density of 0.046 lb/cf)
4 Based on 10% conversion of SO_2
5 Based on a PM emission factor of 0.0068 lb/MMBtu
6 Based on 1 ppmvd at 15 percent O_2

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Table 2-2 Power Generation Unit TAP & HAP Emissions

Compound	CAS #	Emission Factor[1]		Maximum Emission Rate[2]	
		Combustion Turbine (lb/MMBtu)	Duct Burner (lb/MMscf)	(lb/hr)	(tpy)
Acetaldehyde	75-07-0	0.00004	--	0.0828	0.362
Acrolein	107-02-8	0.0000064	--	0.0132	0.058
Ammonia[3]	7664-41-7	based on 5 ppmvd	--	17.2	75.3
Arsenic	7440-38-2	--	0.0002	0.000055	0.000241
Barium	7440-39-3	--	0.0044	0.00121	0.0053
Benzene	71-43-2	0.000012	0.0021	0.0254	0.111
Benzo(a)anthracene	56-55-3	--	0.0000018	0.000000495	0.00000217
Benzo(a)pyrene	50-32-8	--	0.0000012	0.00000033	0.00000145
Benzo(b)fluoranthene	205-99-2	--	0.0000018	0.000000495	0.00000217
Benzo(k)fluoranthene	207-08-9	--	0.0000018	0.000000495	0.00000217
Beryllium	7440-41-7	--	0.000012	0.0000033	0.0000145
1,3-Butadiene	106-99-0	0.00000043	--	0.00089	0.0039
Butane	106-97-8	--	2.1	0.578	2.53
Cadmium	7440-43-9	--	0.0011	0.000303	0.00133
Chromium, total	0-00-5	--	0.0014	0.000385	0.00169
Chromium, hexavalent[4]	18540-29-9	--	0.000056	0.0000154	0.0000675
Chrysene	218-01-9	--	0.0000018	0.000000495	0.00000217
Cobalt	7440-48-4	--	0.000084	0.0000231	0.000101
Copper	7440-50-8	--	0.00085	0.000234	0.00102
Dibenzo(a,h)anthracene	53-70-3	--	0.0000012	0.00000033	0.00000145
7,12-Dimethylbenz(a)anthracene	57-97-6	--	0.000016	0.0000044	0.0000193
Ethylbenzene	100-41-4	0.000032	--	0.0662	0.29
Formaldehyde[5]	50-00-0	0.0001065	0.01125	0.223	0.979
Hexane	110-54-3	--	1.8	0.495	2.17
Indeno(1,2,3-cd)pyrene	193-39-5	--	0.0000018	0.000000495	0.00000217
Manganese	7439-96-5	--	0.00038	0.000105	0.000458
Mercury	7439-97-6	--	0.00026	0.0000715	0.000313
3-Methylchloranthrene	56-49-5	--	0.0000018	0.000000495	0.00000217
Molybdenum	7439-98-7	--	0.0011	0.000303	0.00133
Naphthalene	91-20-3	0.0000013	0.00061	0.00286	0.0125
Nickel	7440-02-0	--	0.0021	0.000578	0.00253
Pentane	109-66-0	--	2.6	0.715	3.13
Polyaromatic Hydrocarbons	PAH	0.0000022	0.0000096	0.00455	0.0199

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Compound	CAS #	Emission Factor[1]		Maximum Emission Rate[2]	
		Combustion Turbine (lb/MMBtu)	Duct Burner (lb/MMscf)	(lb/hr)	(tpy)
Propylene Oxide	75-56-9	0.000029	--	0.06	0.263
Selenium	7784-49-2	--	0.000024	0.0000066	0.0000289
Sulfuric Acid[6]	7664-93-9	based on SO_2	--	2.40	5.79
Toluene	108-88-3	0.00013	0.0034	0.27	1.18
Vanadium	7440-62-2	--	0.0023	0.000633	0.00277
Xylenes	1330-20-7	0.000064	--	0.132	0.58

1 Combustion turbine emission factors are from AP-42 Section 3.1 (Stationary Gas Turbines), and duct burner emission factors are from AP-42 Section 1.4 (External Natural Gas Combustion)
2 Combustion turbine emission rates are based on a maximum heat input of 2,069 MMBtu/hr. Duct burner emission rates are based on a maximum fuel feed rate of 0.275 MMscf/hr.
3 Ammonia emission rate is based on a stack exhaust concentration of 5 ppmvd.
4 ENVIRON assumed 4 percent of total chromium emissions were emitted as chromium VI, based on EPA's 2002 National-Scale Air Toxics Assessment (NATA), released in June 2009, that includes a chromium speciation profile for gas-fired process heaters which indicates 4 percent of total chromium is chromium VI and 96 percent is chromium III.
5 Formaldehyde emission factors were reduced by 85 percent to reflect control provided by the oxidation catalyst. See page 7 of AP-42 Section 3.1.
6 Based on an assumed 10 percent conversion of SO_2 to H_2SO_4. Short-term emission rate is based on a 24-hour average natural gas sulfur content of 2.39 gr/100cf, and the annual emission rate is based on an annual average natural gas sulfur content of 1.31 gr/100cf.

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Table 2-3 Auxiliary Boiler Criteria Pollutant Emission Rates

Pollutant	Emission Factor (lb/MMBtu)	Emission Rate[1]	
		(lb/hr)	(tpy)
NO_X[2]	0.011	0.402	0.879
CO	0.037	1.35	2.96
SO_2[3]	0.00725	0.265	--
	0.00367	--	0.294
$PM_{10}/PM_{2.5}$	0.0077	0.281	0.615
VOC	0.004	0.146	0.320

1 Based on a maximum heat input of 36.5 MMBtu/hr; annual emission rate is based on an assumed 50 percent capacity factor

2 Equivalent to 9 ppmvd at 3 percent O_2

3 Short-term average SO_2 emission factor is based on a natural gas sulfur content of 2.59 gr/100cf; Annual average SO_2 emission factor is based on a natural gas sulfur content of 1.31 gr/100cf

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Table 2-4 Auxiliary Boiler TAP & HAP Emission Rates

Compound	CAS #	Emission Factor[1] (lb/MMscf)	Maximum Emission Rate[2]	
			(lb/hr)	(tpy)
Arsenic	7440-38-2	0.0002	0.00000716	0.0000157
Barium	7440-39-3	0.0044	0.000157	0.000345
Benzene	71-43-2	0.0021	0.0000751	0.000165
Benzo(a)anthracene	56-55-3	0.0000018	6.44E-08	0.000000141
Benzo(a)pyrene	50-32-8	0.0000012	4.29E-08	0.000000094
Benzo(b)fluoranthene	205-99-2	0.0000018	6.44E-08	0.000000141
Benzo(k)fluoranthene	207-08-9	0.0000018	6.44E-08	0.000000141
Beryllium	7440-41-7	0.000012	0.000000429	0.00000094
Butane	106-97-8	2.1	0.0751	0.165
Cadmium	7440-43-9	0.0011	0.0000394	0.0000862
Chromium, hexavalent	18540-29-9	0.000056	0.000002	0.00000439
Chrysene	218-01-9	0.0000018	6.44E-08	0.000000141
Cobalt	7440-48-4	0.000084	0.00000301	0.00000658
Copper	7440-50-8	0.00085	0.0000304	0.0000666
Dibenzo(a,h)anthracene	53-70-3	0.0000012	4.29E-08	0.000000094
7,12-Dimethylbenz(a)anthracene	57-97-6	0.000016	0.000000573	0.00000125
Formaldehyde	50-00-0	0.01125	0.000403	0.000882
Hexane	110-54-3	1.8	0.0644	0.141
Indeno(1,2,3-cd)pyrene	193-39-5	0.0000018	6.44E-08	0.000000141
Manganese	7439-96-5	0.00038	0.0000136	0.0000298
Mercury	7439-97-6	0.00026	0.0000093	0.0000204
3-Methylchloranthrene	56-49-5	0.0000018	6.44E-08	0.000000141
Molybdenum	7439-98-7	0.0011	0.0000394	0.0000862
Naphthalene	91-20-3	0.00061	0.0000218	0.0000478
Nickel	7440-02-0	0.0021	0.0000751	0.000165
Pentane	109-66-0	2.6	0.093	0.204
Polyaromatic Hydrocarbons	PAH	0.0000096	0.000000344	0.000000752
Selenium	7784-49-2	0.000024	0.000000859	0.00000188
Toluene	108-88-3	0.0034	0.000122	0.000266
Vanadium	7440-62-2	0.0023	0.0000823	0.00018

1 Emission factors are from AP-42 Section 1.4 (External Natural Gas Combustion)
2 Based on a maximum heat input of 36.5 MMBtu/hr
3 ENVIRON assumed 4 percent of total chromium emissions were emitted as chromium VI, based on EPA's 2002 National-Scale Air Toxics Assessment (NATA), released in June 2009, that includes a chromium speciation profile for gas-fired process heaters which indicates 4 percent of total chromium is chromium VI and 96 percent is chromium III.

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Table 2-5 Back-Up Generator Criteria Pollutant Emission Rates

Pollutant	Emission Factor[1] (lb/hp-hr)	Emission Rate[2]	
		(lb/hr)	(tpy)
NO_X	0.0057	7.03	0.183
CO	0.00051	0.622	0.0162
SO_2	0.000012	0.0149	0.000387
$PM_{10}/PM_{2.5}$	0.000053	0.0649	0.00169
VOC	0.000066	0.0812	0.00211

1 Emission factors (except NO_X and SO_2) for a representative generator set (Caterpillar Standby 800 ekW 1000 kVA). NO_X emission factor is based on the Tier 4 engine emission standard (without add-on controls) for NO_X. SO_2 emission factor is based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.0015 percent by weight (8.09e-3 × %S)
2 Emission rates based on a 1,225 hp engine. Annual emissions are based on a maximum of 52 hours of non-emergency use per year.

Table 2-6 Emergency Fire Pump Criteria Pollutant Emission Rates

Pollutant	Emission Factor[1] (lb/hp-hr)	Emission Rate[2]	
		(lb/hr)	(tpy)
NO_X	0.00564	1.35	0.0352
CO	0.00132	0.316	0.00821
SO_2	0.000012	0.00291	0.0000757
$PM_{10}/PM_{2.5}$	0.00017	0.0418	0.00109
VOC	0.00015	0.0354	0.000922

1 Emission factors (except SO_2) for a representative fire pump engine (Clarke Model JU6H-UFADR0). SO_2 emission factor is based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.0015 percent by weight (8.09e-3 × %S)
2 Emission rates based on a 240 hp engine. Annual emissions are based on a maximum of 52 hours of non-emergency use per year.

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Table 2-7 Back-Up Generator TAP & HAP Emission Rates

Compound	CAS #	Emission Factor[1] (lb/MMBtu)	Maximum Emission Rate[2]	
			(lb/hr)	(lb/hr)
Acenaphthylene	208-96-8	0.00000923	0.0000793	0.00000206
Acrolein	107-02-8	0.00000788	0.0000677	0.00000176
Anthracene	120-12-7	0.00000123	0.0000106	0.000000275
Benzene	71-43-2	0.000776	0.00667	0.000173
Benzo(a)anthracene	56-55-3	0.000000622	0.00000534	0.000000139
Benzo(a)pyrene	50-32-8	0.000000257	0.00000221	5.74E-08
Benzo(b)fluoranthene	205-99-2	0.00000111	0.00000953	0.000000248
Benzo(g,h,i)perylene	191-24-2	0.000000556	0.00000478	0.000000124
Benzo(k)fluoranthene	207-08-9	0.000000218	0.00000187	4.87E-08
Chrysene	218-01-9	0.00000153	0.0000131	0.000000342
Dibenz(a,h)anthracene	53-70-3	0.000000346	0.00000297	7.73E-08
Diesel Engine Particulate	DEP	Equal to PM_{10}	0.0649	0.00169
Fluoranthene	206-44-0	0.00000403	0.0000346	0.000000900
Fluorene	86-73-7	0.0000128	0.000110	0.00000286
Formaldehyde	50-00-0	0.0000789	0.000678	0.0000176
Indeno(1,2,3-cd)pyrene	193-39-5	0.000000414	0.00000356	9.25E-08
Naphthalene	91-20-3	0.000140	0.00120	0.0000313
Phenanthrene	85-01-8	0.0000408	0.000350	0.00000911
Polyaromatic Hydrocarbons	PAH	0.0000045	0.0000386	0.000001
Propylene	115-07-1	0.00279	0.0240	0.000623
Pyrene	129-00-0	0.00000371	0.0000319	0.000000828
Toluene	108-88-3	0.000281	0.00241	0.0000628
Xylenes	1330-20-7	0.000193	0.00166	0.0000431

1 Emission factors from AP-42 Section 3.4. (Large Stationary Diesel and All Stationary Dual-Fuel Engines), October 1996.

2 Based on a maximum engine output of 1,227 hp and a brake specific-fuel consumption factor of 7,000 Btu/hp-hr (from AP-42 Section 3.4). DEP was assumed to be equal to PM_{10}.

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Table 2-8 Emergency Fire Pump TAP & HAP Emission Rates

Compound	CAS #	Emission Factor[1] (lb/MMBtu)	Maximum Emission Rate[2]	
			(lb/hr)	(lb/hr)
Acetaldehyde	75-07-0	0.000767	0.00129	0.0000335
Acenaphthene	83-32-9	0.00000142	0.00000239	0.0000000620
Acenaphthylene	208-96-8	0.00000506	0.00000850	0.000000221
Acrolein	107-02-8	0.0000925	0.000155	0.00000404
Anthracene	120-12-7	0.00000187	0.00000314	8.17E-08
Benzene	71-43-2	0.000933	0.00157	0.0000408
Benzo(a)anthracene	56-55-3	0.00000168	0.00000282	7.34E-08
Benzo(a)pyrene	50-32-8	0.000000188	0.000000316	8.21E-09
Benzo(b)fluoranthene	205-99-2	9.91E-08	0.000000166	4.33E-09
Benzo(g,h,i)perylene	191-24-2	0.000000489	0.000000822	2.14E-08
Benzo(k)fluoranthene	207-08-9	0.000000155	0.000000260	6.77E-09
1,3-Butadiene	106-99-0	0.0000391	0.0000657	0.00000171
Chrysene	218-01-9	0.000000353	0.000000593	1.54E-08
Dibenz(a,h)anthracene	53-70-3	0.000000583	0.000000979	2.55E-08
Diesel Engine Particulate	DEP	Equal to PM_{10}	0.0418	0.00109
Fluoranthene	206-44-0	0.00000761	0.0000128	0.000000332
Fluorene	86-73-7	0.0000292	0.0000491	0.00000128
Formaldehyde	50-00-0	0.00118	0.00198	0.0000515
Indeno(1,2,3-cd)pyrene	193-39-5	0.000000375	0.000000630	1.64E-08
Naphthalene	91-20-3	0.0000848	0.000142	0.00000370
Phenanthrene	85-01-8	0.0000294	0.0000494	0.00000128
Polyaromatic Hydrocarbons	PAH	0.00000343	0.00000577	0.00000015
Propylene	115-07-1	0.000258	0.000433	0.0000113
Pyrene	129-00-0	0.00000478	0.00000803	0.000000209
Toluene	108-88-3	0.000409	0.000687	0.0000179
Xylenes	1330-20-7	0.000285	0.000479	0.0000124

1 Emission factors from AP-42 Section 3.3. (Gasoline and Diesel Engines), October 1996.

2 Based on a maximum engine output of 240 hp and a brake-specific fuel consumption factor of 7,000 Btu/hp-hr (from AP-42 Section 3.3).

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Table 2-9 Cooling Tower Particulate Matter Emission Rates

Water circulation rate (MMlb/hr)	73
Maximum dissolved solids[1] (ppmw)	2,400
Drift, fraction of circulating water	0.0005%
$PM_{10}/PM_{2.5}$ emission rate (lb/hr)	0.88
$PM_{10}/PM_{2.5}$ emission rate[2] (ton/yr)	3.9

1 Maximum expected total dissolved solids (TDS) in makeup water = 200 parts per million by weight (ppmw); maximum expected TDS in circulating cooling water after twelve cycles = 12 x 200 = 2400 ppmw
2 Based on continuous operation (8,760 hr/yr)

Table 2-10 Cooling Tower TAP & HAP Emission Rates

Compound	CAS #	Emission Factor[1] (ppmw)	Short-term Emission Rate (lb/hr)	Annual Emission Rate (ton/yr)
Ammonia	7664-41-7	2	7.35E-04	3.22E-03
Arsenic	7440-38-2	0.005	1.84E-06	8.04E-06
Chlorine	7782-50-5	2.5	9.18E-04	4.02E-03
Fluorine	7782-41-4	0.3	1.10E-04	4.83E-04
Lead	7439-92-1	0.001	3.67E-07	1.61E-06
Manganese	7439-96-5	2	7.35E-04	3.22E-03
Mercury	7439-97-6	0.0005	1.84E-07	8.04E-07
Selenium	7784-49-2	0.01	3.67E-06	1.61E-05
Silver	7440-22-4	0.001	3.67E-07	1.61E-06

1 Based on raw water analysis of Kalama well water samples taken between 01/19/06 and 01/25/06 (3 samples)

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Table 2-11 Maximum Short-Term Normal Operation Criteria Pollutant Emission Rates

Source	1-hour Average NO_X	1-hour Average CO	8-hour Average CO	1-hour Average SO_2	24-hour Average $PM_{10}/PM_{2.5}$	1-hour Average VOC
Combustion Turbine w/Duct Firing	18.5	11.3	11.3	18.2	17.1	3.22
Combustion Turbine	16.5	10.02	10.02	16.2	15.2	2.86
Combustion Turbine @ 50% Load	10.4	6.33	6.33	10.2	9.61	1.81
Auxiliary Boiler	0.402	1.35	1.35	0.265	0.281	0.146
Diesel Back-Up Generator[1]	7.03	0.622	0.622	0.0149	0.0649	0.0812
Emergency Diesel Fire Pump[1]	1.35	0.316	0.316	0.00291	0.0418	0.0354
Cooling Tower	--	--	--	--	0.882	--
100% Load w/Duct Firing Total	27.3	13.6	13.6	18.5	18.4	3.49
100% Load Total	25.3	12.3	12.3	16.5	16.5	3.13
50% Load Total	19.2	8.62	8.62	10.53	10.88	2.07
Worst Case Total	27.3	13.6	13.6	18.5	18.4	3.49

1 Diesel engines will never be operated concurrently or for more than one hour in any given 24-hour period for testing and maintenance purposes.

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Table 2-12 Power Generation Unit Startup and Shutdown

Mode[1]	Time[2] (min)	Fuel Use[3] (lb/event)	Pollutant Emitted[4] (lb/event)				
			NO_X	CO	VOC	PM	SO_2
"Cold" Startup	37	23,548	83	370	112	5.4	1.87
"Warm" Startup	37	26,900	85	220	88	5.9	2.14
"Hot" Startup	32	23,688	73	183	73	5.3	1.89
Shutdown from 100% Load	37	39,906	37	69	28	7.3	3.18
Shutdown from 75% Load	12	9,321	30	68	27	2.2	0.74

1 Mode definitions: "Cold" Startup, > 64 hours since shutdown; "Warm" Startup, 16-64 hours since shutdown; "Hot" Startup, < 16 hours since shutdown.
2 For startups, time until emissions comply with permit emission limits; for shutdown, time until shutdown is complete. Times provided by Siemens.
3 Fuel use provided by Siemens
4 Pollutant quantities provided by Siemens, except for SO_2, which was calculated using the fuel use and maximum short-term sulfur content of the natural gas with a 25 percent safety factor (0.557 grains per pound)

Table 2-13 Maximum Short-Term Startup/Shutdown Scenario Emission Rates

Pollutant	Averaging Period	Average Emission Rate (lb/hr)	Worst Case Scenario Description
NO_X	1-hr	92	Warm start, normal operation
CO	1-hr	374	Cold start, normal operation
	8-hr	93.8	Cold start, hot start, two shutdowns, and 1 hour down
SO_2	1-hr	10.40	Hot start, normal operation
	3-hr	14.66	Hot start, normal operation, shutdown
	24-hr	17.80	Hot start, normal operation, shutdown
$PM_{10}/PM_{2.5}$	24-hr	16.91	Hot start, normal operation, shutdown
VOC	1-hr	113.24	Cold start, normal operation

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Table 2-14 Facility-Wide Annual Criteria Pollutant Emission Rates (tons per year)

Source	NO_x	CO	SO_2	H_2SO_4	$PM_{10}/PM_{2.5}$	VOC
Annual emissions with continuous PGU operation						
PGU @ 100% Load with Duct Firing	75.7	46.1	37.8	5.79	70.0	13.2
PGU @ 100% Load	66.4	40.4	33.1	5.07	61.4	11.5
PGU @ 50% Load	42.8	26.1	21.4	3.37	39.6	7.45
Maximum PGU Scenario	75.7	46.1	37.8	5.79	70.0	13.2
Auxiliary Boiler[1]	0.879	2.96	0.294	--	0.615	0.320
Diesel Back-Up Generator[2]	0.183	0.0162	0.000387	--	0.00169	0.00211
Diesel Fire Pump[2]	0.0352	0.00821	0.0000757	--	0.00109	0.000922
Cooling Tower[3]	--	--	--	--	3.86	--
Maximum Facility-wide Emissions	76.8	49.1	38.1	5.79	74.5	13.5
Annual Emissions with Maximum Annual PGU Startups and Shutdowns						
PGU	102.4	131.1	32.8	5.03	62.6	47.8
Auxiliary Boiler[1]	0.879	2.96	0.294	--	0.615	0.320
Diesel Back-Up Generator[2]	0.183	0.0162	0.000387	--	0.00169	0.00211
Diesel Fire Pump[2]	0.0352	0.0082	0.000076	--	0.00109	0.000922
Cooling Tower[3]	--	--	--	--	3.86	--
Maximum Facility-wide Emissions	103.5	134.0	33.1	5.03	67.1	48.1
Maximum Annual Emissions – All Scenarios						
Maximum Facility Wide Emissions	103.5	134.0	38.1	5.79	74.5	48.1
PSD Significant Emission Rate	40	100	40	7	15/10	40

1 50 percent annual capacity factor
2 Maximum of 52 hours per year of non-emergency operation
3 Total for 6-cell cooling tower

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Table 2-15 Facility-Wide Greenhouse Gas Emission Rates

Emission Unit	Activity	Maximum Annual Operation (hr/yr)	GHG	Emission Factor[1]	Emission Rate[2]	
					(lb/hr)	(tpy)
PGU	2,350 MMBtu/hr	8,760	CO_2	117 lb/MMBtu	274,630	1,202,880
			CH_4	0.00220 lb/MMBtu	5.18	22.7
			N_2O	0.000220 lb/MMBtu	0.518	2.27
			CO_2e	--	274,899	1,204,060
Auxiliary Boiler	36.5 MMBtu/hr	4,380	CO_2	117 lb/MMBtu	4,266	9,343
			CH_4	0.00220 lb/MMBtu	0.08	0.176
			N_2O	0.000220 lb/MMBtu	0.008	0.0176
			CO_2e	--	4,271	9,353
Back-up Generator Diesel Engine	57.2 gal/hr	52	CO_2	22.5 lb/gal	1,287	33.5
			CH_4	0.000913 lb/gal	0.05	0.00136
			N_2O	0.000183 lb/gal	0.010	0.000271
			CO_2e	--	1,291	33.6
Emergency Fire Pump Diesel Engine	12 gal/hr	52	CO_2	22.5 lb/gal	270	7.02
			CH_4	0.000913 lb/gal	0.01	0.000285
			N_2O	0.000183 lb/gal	0.002	0.0000570
			CO_2e	--	271	7.04
Circuit Breakers	161 lb SF_6/unit[4]	3 units	SF_6	1% leakage/year/unit[5]	0.000551	0.00242
			CO_2e		13.2	57.7
Total	--		CO_2	--	280,454	1,212,264
			CH_4		5.32	22.9
			N_2O		0.539	2.29
			SF_6		0.000551	0.00242
			CO_2e		280,746	1,213,511

1 The emission factors for combustion of natural gas (for the PGU 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, and N_2O – 310), and summing. For example:
(274,630 lb CO_2/hr * 1 lb CO_2e/lb CO_2) + (5.18 lb CH_4/hr * 21 lb CO_2e/lb CH_4) + (0.518 lb N_2O/hr * 310 lb CO_2e/lb N_2O) = 274,630 lb CO_2e/hr + 108.8 lb CO_2e/hr + 160.6 lb CO_2e/hr = 274,899 lb CO_2e/hr

4 Quantity of SF_6 in a typical 230 kV-class circuit breaker.

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

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Table 3-1 Facility-Wide HAP Emission Rates

Compound	CAS #	Power Generation Unit	Auxiliary Boiler	Cooling Tower	Back-Up Generator	Diesel Fire Pump	Total
Acetaldehyde	75-07-0	0.362	0	0	0.00000563	0.0000335	0.363
Acrolein	107-02-8	0.058	0	0	0.00000176	0.00000404	0.058
Arsenic	7440-38-2	0.000241	0.0000157	0.00000804	0	0	0.000265
Benzene	71-43-2	0.111	0.000165	0	0.000173	0.0000408	0.112
Beryllium	7440-41-7	0.0000145	0.00000094	0	0	0	0.0000154
1,3-Butadiene	106-99-0	0.0039	0	0	0	0.00000171	0.0039
Cadmium	7440-43-9	0.00133	0.0000862	0	0	0	0.00141
Chlorine	7782-50-5	0	0	0.00402	0	0	0.00402
Chromium, hexavalent	18540-29-9	0.0000675	0.00000439	0	0	0	0.0000719
Cobalt	7440-48-4	0.000101	0.00000658	0	0	0	0.000108
Ethyl benzene	100-41-4	0.29	0	0	0	0	0.29
Formaldehyde	50-00-0	0.979	0.000882	0	0.0000176	0.0000515	0.98
Hexane	110-54-3	2.17	0.141	0	0	0	2.31
Lead	7439-92-1	0	0	0.00000161	0	0	0.00000161
Manganese	7439-96-5	0.000458	0.0000298	0.00322	0	0	0.00371
Mercury	7439-97-6	0.000313	0.0000204	0.000000804	0	0	0.000334
Naphthalene	91-20-3	0.0125	0.0000478	0	0.0000313	0.0000037	0.0126
Nickel	7440-02-0	0.00253	0.000165	0	0	0	0.0027
Polycyclic Organic Matter	POM	0.0000193	0.00000691	0	0.0000182	0.00000364	0.000048
Propylene	115-07-1	0	0	0	0.000623	0.0000113	0.000634
Propylene Oxide	75-56-9	0.263	0	0	0	0	0.263
Selenium	7784-49-2	0.0000289	0.00000188	0.0000161	0	0	0.0000469
Toluene	108-88-3	1.18	0.000266	0	0.0000628	0.0000179	1.18
Xylenes	1330-20-7	0.58	0	0	0.0000431	0.0000124	0.58
Total HAPs							6.17
Maximum HAP							2.31

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Table 3-2 Facility-Wide TAP Emission Rates (pre-June-2009 Regulations)

Compound	CAS #	TAP Class	Facility Wide Emission Rate		Small Quantity Emission Rate (SQER)[1]			Modeling Required?
			(lb/hr)	(lb/yr)	Class A (lb/yr)	Class B (lb/yr)	Class B (lb/hr)	
Acetaldehyde	75-07-0	A	0.0843	725	50	-	-	Yes
Acrolein	107-02-8	B	0.0135	116	-	175	0.02	No
Ammonia	7664-41-7	B	17.2	151,000	-	17500	2	Yes
Arsenic	7440-38-2	A	0.000064	0.529	**	-	-	Yes
Barium	7440-39-3	B	0.00137	11.3	-	175	0.02	No
Benzene	71-43-2	A	0.0337	223	20	-	-	Yes
Beryllium	7440-41-7	A	3.73E-06	0.0308	**	-	-	Yes
1,3-Butadiene	106-99-0	A	0.000955	7.8	0.5	-	-	Yes
Butane	106-97-8	B	0.653	5,390	-	43748	5	No
Cadmium	7440-43-9	A	0.000342	2.82	**	-	-	Yes
Chlorine	7782-50-5	B	0.000918	8.04	-	175	0.02	No
Chromium, hexavalent	18540-29-9	A	1.74E-05	0.144	**	-	-	Yes
Cobalt	7440-48-4	B	2.61E-05	0.216	-	175	0.02	No
Copper	7440-50-8	B	0.000264	2.18	-	175	0.02	No
Ethyl benzene	100-41-4	B	0.0662	580	-	22750	2.6	No
Fluorine	7782-41-4	B	0.00011	0.965	-	175	0.02	No
Formaldehyde	50-00-0	A	0.226	1,960	20	-	-	Yes
Hexane	110-54-3	B	0.56	4,620	-	22750	2.6	No
Lead	7439-92-1	A	3.67E-07	0.00322	50	-	-	No
Manganese	7439-96-5	B	0.000853	7.41	-	175	0.02	No
Mercury	7439-97-6	B	0.000081	0.669	-	175	0.02	No
Molybdenum	7439-98-7	B	0.000342	2.82	-	5250	0.6	No
Naphthalene	91-20-3	B	0.00422	25.2	-	22750	2.6	No
Nickel	7440-02-0	A	0.000653	5.39	0.5	-	-	Yes
Pentane	109-66-0	B	0.808	6,670	-	43748	5	No
Polyaromatic Hydrocarbons[3]	PAH	A	0.00460	39.9	**	-	-	Yes
Propylene Oxide	75-56-9	A	0.06	526	50	-	-	Yes
Selenium	7784-49-2	B	1.11E-05	0.0938	-	175	0.02	No
Silver	7440-22-4	B	3.67E-07	0.00322	-	175	0.02	No
Sulfuric acid	7664-93-9	B	2.40	11,600	-	175	0.02	Yes
Toluene	108-88-3	B	0.273	2,360	-	43748	5	No
Vanadium	7440-62-2	B	0.000715	5.9	-	175	0.02	No
Xylenes	1330-20-7	B	0.135	1,160	-	43748	5	No

1 Small Quantity Emission Rates are defined in WAC 173-460-090(e) (pre-June 2009)
2 Per WAC 173-460-090(e), TAPs with ASILs less than 0.001 µg/m3 are required to use dispersion modeling to demonstrate compliance with the ASIL; there is no SQER (pre-June 2009)
3 PAH emission rate calculated per WAC 173-460-050(c) (pre-June 2009)

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Table 3-3 Facility-Wide TAP Emission Rates (post-June-2009 Regulations)

Compound	CAS #	Averaging Period	Facility-Wide Emission Rate (lb/avg per)	SQER[1] (lb/avg per)	Model?
Acetaldehyde	75-07-0	year	725	71	Yes
Acrolein	107-02-8	24-hr	0.323	0.00789	Yes
Ammonia	7664-41-7	24-hr	412	9.31	Yes
Arsenic	7440-38-2	year	0.529	0.0581	Yes
Benzene	71-43-2	year	224	6.62	Yes
Benzo(a)anthracene	56-55-3	year	0.00544	1.74	No
Benzo(a)pyrene	50-32-8	year	0.00333	0.174	No
Benzo(b)fluoranthene	205-99-2	year	0.00559	1.74	No
Benzo(k)fluoranthene	207-08-9	year	0.00483	1.74	No
Beryllium	7440-41-7	year	0.0308	0.08	No
1,3-Butadiene	106-99-0	year	7.8	1.13	Yes
Cadmium	7440-43-9	year	2.82	0.0457	Yes
Chlorine (Cl)	7782-50-5	24-hr	0.022	0.026	No
Chromium, (hexavalent)	18540-29-9	year	0.144	0.00128	Yes
Chrysene	218-01-9	year	0.00599	17.4	No
Cobalt	7440-48-4	24-hr	0.000627	0.013	No
Copper	7440-50-8	1-hr	0.000264	0.219	No
Dibenzo(a,h)anthracene	53-70-3	year	0.00348	0.16	No
Diesel Engine Particulate	DEP	year	10.7	0.639	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	year	0.0411	0.00271	Yes
Ethylbenzene	100-41-4	year	580	76.8	Yes
Fluorine (F)	7782-41-4	24-hr	0.00264	1.71	No
Formaldehyde	50-00-0	year	1,960	32	Yes
Hexane	110-54-3	24-hr	13.4	92	No
Indeno(1,2,3-cd)pyrene	193-39-5	year	0.00504	1.74	No
Lead	7439-92-1	year	0.00322	16	No
Manganese	7439-96-5	24-hr	0.0205	0.00526	Yes
Mercury	7439-97-6	24-hr	0.00194	0.0118	No
3-Methylchloranthrene	56-49-5	year	0.00462	0.0305	No
Naphthalene	91-20-3	year	25.3	5.64	Yes
Propylene	115-07-1	24-hr	0.586	394	No
Propylene Oxide	75-56-9	year	526	51.8	Yes
Selenium	7784-49-2	24-hr	0.000267	2.63	No
Sulfuric acid	7664-93-9	24-hr	57.7	0.131	Yes
Toluene	108-88-3	24-hr	6.55	657	No
Vanadium	7440-62-2	24-hr	0.0172	0.0263	No
Xylenes	1330-20-7	24-hr	3.23	29	No

1 Small Quantity Emission Rates are defined in WAC 173-460-090(e) (pre-June 2009)

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Table 4-1 Seasonal Surface Characteristics in Area Surrounding Meteorological Station

Sector	Winter			Spring		
	Albedo	Bowen Ratio	Surface Roughness Length (z_o) (m)	Albedo	Bowen Ratio	Surface Roughness Length (z_o) (m)
1	0.15	0.68	0.071	0.14	0.53	0.076
2	0.15	0.68	0.732	0.14	0.53	0.863
3	0.15	0.68	0.493	0.14	0.53	0.613
4	0.15	0.68	0.299	0.14	0.53	0.379
5	0.15	0.68	0.532	0.14	0.53	0.625
6	0.15	0.68	0.405	0.14	0.53	0.449
7	0.15	0.68	0.3	0.14	0.53	0.31
8	0.15	0.68	0.018	0.14	0.53	0.019
9	0.15	0.68	0.011	0.14	0.53	0.011
10	0.15	0.68	0.015	0.14	0.53	0.015
11	0.15	0.68	0.009	0.14	0.53	0.01
12	0.15	0.68	0.03	0.14	0.53	0.034
Sector	Summer			Fall		
	Albedo	Bowen Ratio	Surface Roughness Length (z_o) (m)	Albedo	Bowen Ratio	Surface Roughness Length (z_o) (m)
1	0.15	0.3	0.077	0.15	0.68	0.077
2	0.15	0.3	0.921	0.15	0.68	0.921
3	0.15	0.3	0.778	0.15	0.68	0.778
4	0.15	0.3	0.552	0.15	0.68	0.552
5	0.15	0.3	0.677	0.15	0.68	0.677
6	0.15	0.3	0.471	0.15	0.68	0.471
7	0.15	0.3	0.315	0.15	0.68	0.315
8	0.15	0.3	0.019	0.15	0.68	0.019
9	0.15	0.3	0.011	0.15	0.68	0.011
10	0.15	0.3	0.016	0.15	0.68	0.016
11	0.15	0.3	0.01	0.15	0.68	0.01
12	0.15	0.3	0.036	0.15	0.68	0.036

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Table 4-2 Emission Unit Modeling Release Parameters

Source	Number of Emission Points	Stack Base Elevation (m)/(ft)	Release Height (m)/(ft)	Exhaust Temperature (K)/(F)	Exit Velocity (m/s)/(ft/s)	Inside Diameter (m)/(ft)
PGU @ 100% Load w/Duct Firing	1	4.41 / 14.5	42.7 / 140	349 / 169	19.3 / 63.3	6.10 / 20.0
PGU @ 100% Load	1	4.41 / 14.5	42.7 / 140	360 / 189	19.8 / 65.0	6.10 / 20.0
PGU @ 50% Load	1	4.41 / 14.5	42.7 / 140	349 / 169	12.8 / 42.0	6.10 / 20.0
Auxiliary Boiler	1	4.41 / 14.5	25.9 / 85.0	422 / 300	9.87 / 32.4	0.838 / 2.75
Back-Up Generator	1	4.41 / 14.5	8.53 / 28.0	786 / 955	88.0 / 289	0.203 / 0.67
Firewater Pump	1	4.70 / 15.4	8.53 / 28.0	622 / 660	57.4 / 188	0.127 / 0.417
Cooling Tower	6	4.75 / 15.6	14.6 / 48.0	313 / 104	8.14 / 26.7	10.1 / 33.0

Table 4-3 Heights Above Grade of Significant Structures

Structure	Height	
	(m)	(ft)
Combustion Turbine Building	6.1	20
HRSG Structure	24.7	81
Steam Turbine Building	20.4	67
Cooling Tower	14.6	48
Auxiliary Boiler Building	6.7	22
Boiler Feed Pump Building	11.3	37
Back- Up Generator Building	6.7	22
Firewater Pump Building	6.7	22
Demineralized Water Tank	6.7	22
Fresh Water Tank	13.7	45
Administration Building	6.7	22
Electrical Building	11.3	37
Water Treatment Building	11.3	37

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Table 4-4 Maximum Predicted Criteria Pollutant Concentrations During Normal Operation

Pollutant	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Over/Under SIL?	Significant Monitoring Concentration ($\mu g/m^3$)	Over/Under SMC?
CO	1-Hour	47.9	2,000	Under	--	--
	8-Hour	25.0	500	Under	575	Under
NO_2[1]	1-Hour	184	7.5	Over	--	--
	Annual	0.220	1	Under	14	Under
PM_{10}	24-Hour	3.05	5	Under	10	Under
	Annual	0.171	1	Under	--	--
$PM_{2.5}$	24-Hour	3.05	1.2	Over	4	Under
	Annual	0.170	0.3	Under	--	--
SO_2	1-Hour	31.4	7.8[2]	Over	--	--
	3-Hour	21.3	25	Under	--	--
	24-Hour	2.47	5	Under	13	Under
	Annual	0.0726	1	Under	--	--

1 Conversion of NO to NO_2 was calculated by AERMOD using the PVMRM option (see Section 4.2.3) for the 1-hour average. Annual average conversion was assumed to be 75 percent.
2 The SIL for the 1-hour average Washington Ambient Air Quality Standard for SO_2 is 30 $\mu g/m^3$ (WAC 173-400-113).

Table 4-5 Normal Operation Ambient Standard Compliance Analysis

Pollutant	Averaging Period	Design Concentration[1]	PSD Increment	Background Concentration[2]	Total Concentration[3]	NAAQS
NO_2	1-Hour	112	--	73.4	185	188
$PM_{2.5}$	24-Hour	3.05	9	19.0	22.5	35
SO_2	1-Hour	18.2	--	138	156	196[4]

Note: All concentrations and standards are in $\mu g/m^3$
1 For NO_2 the design concentration is the 98th percentile of the maximum daily predicted 1-hour NO_2 concentrations. Conversion of NO to NO_2 was calculated by AERMOD using the PVMRM option (see Section 4.2.3). For $PM_{2.5}$, the design concentration is the maximum predicted 24-hour average $PM_{2.5}$ concentration, per USEPA's February 26, 2010 memorandum titled *Modeling Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS*. For SO_2 the design concentration is the 99th percentile of the maximum daily predicted 1-hour NO_2 concentrations.
2 The NO_2 background concentration is 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour average concentrations recorded at ODEQ's Portland-Lafayette monitoring station from 2007 through 2009. The $PM_{2.5}$ background concentration is a 3-year average of the 98th percentile of the daily 24-hour average concentrations recorded at WDOE's Longview-30th Ave monitoring station from 2007 through 2009. The SO_2 background concentration is the maximum 1-hour SO_2 concentration recorded at the Beacon Hill monitoring site (EPA ID: 530330080) from 2005 – 2009 (data accessed from EPA's AQS Data Mart website).
3 Total Concentration = Design Concentration + Background Concentration
4 The 1-hour average Washington Ambient Air Quality Standard for SO_2 is 1,050 $\mu g/m^3$.

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Table 4-6 Maximum Predicted TAP Concentrations (pre-June-2009 Regulations)

Compound	CAS #	TAP Class	Averaging Period	Maximum Predicted Concentration (µg/m^3)	ASIL (µg/m^3)	Over ASIL?
Acetaldehyde	75-07-0	A	Annual	0.00062	0.45	No
Ammonia	7664-41-7	B	24-Hour	2.52	100	No
Arsenic	7440-38-2	A	Annual	3.84E-06	0.00023	No
Benzene	71-43-2	A	Annual	0.00019	0.12	No
Beryllium	7440-41-7	A	Annual	2.29E-07	0.00042	No
1,3-Butadiene	106-99-0	A	Annual	6.65E-06	0.0036	No
Cadmium	7440-43-9	A	Annual	0.000021	0.00056	No
Chromium, hexavalent	18540-29-9	A	Annual	1.06E-06	0.000083	No
Formaldehyde	50-00-0	A	Annual	0.00167	0.077	No
Nickel	7440-02-0	A	Annual	0.000040	0.0021	No
Polyaromatic Hydrocarbons	PAH	A	Annual	0.0000340	0.00048	No
Propylene Oxide	75-56-9	A	Annual	0.00045	0.27	No
Sulfuric acid	7664-93-9	B	24-Hour	0.511	3.3	No

Table 4-7 Maximum Predicted TAP Concentrations (post-June-2009 Regulations)

Compound	CAS #	Averaging Period	Maximum Predicted Concentration (µg/m^3)	ASIL (µg/m^3)	Over ASIL?
Acetaldehyde	75-07-0	Annual	0.00062	0.37	No
Acrolein	107-02-8	24-Hour	0.0069	0.06	No
Ammonia	7664-41-7	24-Hour	2.52	70.8	No
Arsenic	7440-38-2	Annual	3.84E-06	0.000303	No
Benzene	71-43-2	Annual	0.00019	0.0345	No
Beryllium	7440-41-7	Annual	2.29E-07	0.000417	No
1,3-Butadiene	106-99-0	Annual	6.65E-06	0.00588	No
Cadmium	7440-43-9	Annual	0.000021	0.000238	No
Chromium, hexavalent	18540-29-9	Annual	1.06E-06	6.67E-06	No
Diesel Engine Particulate	DEP	Annual	0.00265	0.00333	No
7,12-Dimethylbenz(a)anthracene	57-97-6	Annual	3.05E-07	0.0000141	No
Ethylbenzene	100-41-4	Annual	0.00049	0.4	No
Formaldehyde	50-00-0	Annual	0.00167	0.167	No
Manganese	7439-96-5	24-Hour	0.00128	0.04	No
Naphthalene	91-20-3	Annual	3E-11	0.0294	No
Propylene Oxide	75-56-9	Annual	0.00045	0.27	No
Sulfuric acid	7664-93-9	24-Hour	0.511	1	No

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Table 4-8 Maximum Predicted Criteria Pollutant Concentrations Incorporating Startup and Shutdown Operations

Pollutant	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Over/Under SIL?	Significant Monitoring Concentration ($\mu g/m^3$)	Over/Under SMC?
CO	1-Hour	644	2,000	Under	--	--
	8-Hour	41.2	500	Under	575	Under
NO_2[1]	1-Hour	184	7.5	Over	--	--
	Annual	0.24	1	Under	14	Under
PM_{10}	24-Hour	3.30	5	Under	10	Under
	Annual	0.24	1	Under	--	--
$PM_{2.5}$	24-Hour	3.3	1.2[3]	Over	4	Under
	Annual	0.24	0.3[3]	Under	--	--
SO_2	1-Hour	10.4	7.8[4]	Over	--	--
	3-Hour	17.1	25	Under	--	--
	24-Hour	2.6	5	Under	13	Under
	Annual	0.08	1	Under	--	--

1 Conversion of NO to NO_2 was calculated by AERMOD using the PVMRM option (see Section 4.2.3) for the 1-hour average. Annual average conversion was assumed to be 75 percent.
2 The SIL for the 1-hour average Washington Ambient Air Quality Standard for SO_2 is 30 $\mu g/m^3$ (WAC 173-400-113).

Table 4-9 Short-Term NO_2 and $PM_{2.5}$ Ambient Standard Compliance Analysis Incorporating Startup and Shutdown Operations

Pollutant	Averaging Period	Design Concentration[1]	PSD Increment	Background Concentration[2]	Total Concentration[3]	NAAQS
NO_2	1-Hour	112	--	73.4	185	188
$PM_{2.5}$	24-Hour	3.30	9	19.0	22.3	35
SO_2	1-Hour	10.4	--	138	148	196[4]

Note: All concentrations and standards are in $\mu g/m^3$
1 For NO_2 the design concentration is the 98th percentile of the maximum daily predicted 1-hour NO_2 concentrations. Conversion of NO to NO_2 was calculated by AERMOD using the PVMRM option (see Section 4.2.3). For $PM_{2.5}$, the design concentration is the maximum predicted 24-hour average $PM_{2.5}$ concentration, per USEPA's February 26, 2010 memorandum titled *Modeling Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS*.
2 The NO_2 background concentration is 3-year average of the 98th percentile of the annual distribution of the daily maximum 1-hour average concentrations recorded at ODEQ's Portland-Lafayette monitoring station from 2007 through 2009. The $PM_{2.5}$ background concentration is a 3-year average of the 98th percentile of the daily 24-hour average concentrations recorded at WDOE's Longview-30th Ave monitoring station from 2007 through 2009
3 Total Concentration = Design Concentration + Background Concentration
4 The 1-hour average Washington Ambient Air Quality Standard for SO_2 is 1,050 $\mu g/m^3$.

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Table 5-1 Class I Areas and Results of Q/D Analyses

Class I Area / Area of Interest	Distance (km)	Q/D	
		Normal	Startup
Alpine Lakes Wilderness	176	1.4	1.8
Glacier Peak Wilderness	240	1.0	1.3
Goat Rocks Wilderness	108	2.3	2.9
Mt. Adams Wilderness	95	2.6	3.3
Mt. Hood Wilderness	102	2.5	3.1
Mt. Jefferson Wilderness	153	1.6	2.1
Mt. Rainier National Park	103	2.4	3.1
Mt. Washington Wilderness	192	1.3	1.6
Olympic National Park	160	1.6	2.0
Three Sisters Wilderness	206	1.2	1.5
Columbia River Gorge National Scenic Area	62	4.0	5.1
Q (tpy)		250	316
Max Q/D (incl. CRGNSA)		4.0	5.1
Max Class I Area Q/D		2.6	3.3

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Table 5-2 PMEC 24-Hour Average Normal Operation Emission Rates Speciated for Class I Analysis

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
CTG No. 1	25.80	33.92	27.61	3.00	2.18	6.90	17.71	0.00	0.00
CTG No. 2	25.80	33.92	27.61	3.00	2.18	6.90	17.71	0.00	0.00
Tank Vent Oxidizer	3.91	19.50	0.65	0.65	0.47	0.00	0.00	0.00	0.00
Auxiliary Boiler	0.32	4.68	0.65	0.20	0.15	0.16	0.29	0.00	0.00
Flare	0.01	0.14	0.02	0.00	0.00	0.00	0.01	0.00	0.00
Emerg. Diesel Generator	0.05	1.17	0.04	0.00	0.00	0.03	0.00	0.00	0.00
Emerg. Diesel Fire Pump	0.01	0.21	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Power Block Cool Towers	0.00	0.00	1.76	0.00	0.00	0.00	0.00	1.76	0.00
Dome Ventilation	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.05	0.10
Gasif/ASU Cool Towers	0.00	0.00	0.97	0.00	0.00	0.00	0.00	0.97	0.00
Fugitive Train Unloading	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Fugitive Ship Unloading	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.11	0.24
Fugitive Dome Transfer	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Ship Exhaust	5.31	11.97	0.61	0.07	0.05	0.54	0.00	0.00	0.00
Total	61.20	105.51	60.59	6.93	5.04	14.55	35.71	2.94	0.46

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Table 5-3 KEC 24-Hour Average Normal Operation Emission Rates Speciated for Class I Analysis

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
Combustion Turbine w/Duct Firing	17.77	19.23	17.77	2.00	1.45	4.44	11.33	0.00	0.00
Auxiliary Boiler	0.28	0.55	0.28	0.17	0.13	0.07	0.04	0.00	0.00
Emergency Diesel Back-up Generator	0.06	7.03	0.06	0.01	0.01	0.06	0.00	0.00	0.00
Emergency Diesel Fire Pump	0.04	1.35	0.04	0.00	0.00	0.04	0.00	0.00	0.00
Cooling Tower	0.88	0.00	0.88	0.00	0.00	0.00	0.00	0.88	0.00
Total	19.04	28.16	19.04	2.19	1.59	4.61	11.36	0.88	0.00

Table 5-4 Comparison of KEC and PMEC 24-Hour Average Normal Operation Emission Rates

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
KEC CT/PMEC CTs (2 units)	34%	28%	32%	33%	33%	32%	32%	--	--
KEC Aux Boiler/PMEC Aux Boiler	87%	12%	43%	87%	87%	43%	13%	--	--
KEC Emerg Gen/PMEC Emerg Gen	144%	599%	177%	177%	177%	177%	--	--	--
KEC Fire Pump/PMEC Fire Pump	827%	631%	380%	380%	380%	380%	--	--	--
KEC Cooling Tower/PMEC PB Cool Tower	--	--	50%	--	--	--	--	50%	--
KEC Total/PMEC Total	31%	27%	31%	32%	32%	32%	32%	30%	0%

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Table 5-5 PMEC 24-Hour Average Startup Operation Emission Rates Speciated for Class I Analysis

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
CTG No. 1	25.80	55.69	27.61	3.00	2.18	6.90	17.71	0.00	0.00
CTG No. 2	25.80	55.69	27.61	3.00	2.18	6.90	17.71	0.00	0.00
Tank Vent Oxidizer	3.91	19.50	0.65	0.65	0.47	0.00	0.00	0.00	0.00
Auxiliary Boiler	0.32	4.68	0.65	0.20	0.15	0.16	0.29	0.00	0.00
Flare	18.46	58.47	6.68	1.90	1.38	1.67	3.11	0.00	0.00
Emerg. Diesel Generator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emerg. Diesel Fire Pump	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Power Block Cool Towers	0.00	0.00	1.76	0.00	0.00	0.00	0.00	1.76	0.00
Dome Ventilation	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Gasif/ASU Cool Towers	0.00	0.00	1.03	0.00	0.00	0.00	0.00	1.03	0.00
Fugitive Train Unloading	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Fugitive Ship Unloading	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.11	0.24
Fugitive Dome Transfer	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Ship Exhaust	5.31	11.97	0.61	0.07	0.05	0.54	0.00	0.00	0.00
Total	79.60	206.00	67.21	8.82	6.42	16.18	38.81	2.98	0.42

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Table 5-6 KEC 24-Hour Average Startup Operation Emission Rates Speciated for Class I Analysis

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
Combustion Turbine w/Duct Firing	18.94	32.52	17.77	2.00	1.45	4.44	11.33	0.00	0.00
Auxiliary Boiler	0.28	0.55	0.28	0.17	0.13	0.07	0.04	0.00	0.00
Emergency Diesel Back-up Generator	0.06	7.03	0.06	0.01	0.01	0.06	0.00	0.00	0.00
Emergency Diesel Fire Pump	0.04	1.35	0.04	0.00	0.00	0.04	0.00	0.00	0.00
Cooling Tower	0.88	0.00	0.88	0.00	0.00	0.00	0.00	0.88	0.00
Total	20.21	41.46	19.04	2.19	1.59	4.61	11.36	0.88	0.00

Table 5-7 Comparison of KEC and PMEC 24-Hour Average Startup Operation Emission Rates

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
KEC CT/PMEC CTs (2 units)	37%	29%	32%	33%	33%	32%	32%	--	--
KEC Aux Boiler/PMEC Aux Boiler	87%	12%	43%	87%	87%	43%	13%	--	--
KEC Emerg Gen/PMEC Emerg Gen	--	--	--	--	--	--	--	--	--
KEC Fire Pump/PMEC Fire Pump	--	--	--	--	--	--	--	--	--
KEC Cooling Tower/PMEC PB Cool Tower	--	--	50%	--	--	--	--	50%	--
KEC Total/PMEC Total	25%	20%	28%	25%	25%	28%	29%	30%	0%

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Table 5-8 PMEC Annual Average Worst-Case Emission Rates Speciated for Class I Analysis

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
CTG No. 1	17.20	35.90	27.61	3.00	2.18	6.90	17.71	0.00	0.00
CTG No. 2	17.20	35.90	27.61	3.00	2.18	6.90	17.71	0.00	0.00
Tank Vent Oxidizer	3.77	4.50	0.15	0.15	0.11	0.00	0.00	0.00	0.00
Auxiliary Boiler	0.11	1.17	0.16	0.07	0.05	0.04	0.05	0.00	0.00
Flare	0.93	3.21	0.37	0.10	0.07	0.09	0.18	0.00	0.00
Emerg. Diesel Generator	0.01	0.32	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Emerg. Diesel Fire Pump	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Power Block Cool Towers	0.00	0.00	1.76	0.00	0.00	0.00	0.00	1.76	0.00
Dome Ventilation	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.05	0.10
Gasif/ASU Cool Towers	0.00	0.00	0.89	0.00	0.00	0.00	0.00	0.89	0.00
Fugitive Train Unloading	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01
Fugitive Ship Unloading	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.02	0.03
Fugitive Dome Transfer	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.01
Ship Exhaust	0.76	1.71	0.09	0.01	0.01	0.08	0.00	0.00	0.00
Total	39.99	82.78	58.86	6.33	4.60	14.03	35.65	2.72	0.15

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Table 5-9 KEC Annual Average Worst-Case Emission Rates Speciated for Class I Analysis

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
Combustion Turbine	8.86	22.26	16.40	2.00	1.45	4.10	10.30	0.00	0.00
Auxiliary Boiler	0.07	0.27	0.14	0.04	0.03	0.04	0.06	0.00	0.00
Emergency Diesel Back-up Generator	0.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency Diesel Fire Pump	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	0.00	0.00	0.88	0.00	0.00	0.00	0.00	0.88	0.00
Total	8.93	22.58	17.42	2.04	1.48	4.14	10.36	0.88	0.00

Table 5-10 Comparison of KEC and PMEC Annual Average Worst-Case Emission Rates

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2SO_4$	SO_4	EC	OC	PMF	PMC
KEC CT/PMEC CTs (2 units)	26%	31%	30%	33%	33%	30%	29%	--	--
KEC Aux Boiler/PMEC Aux Boiler	59%	23%	86%	59%	59%	86%	124%	--	--
KEC Emerg Gen/PMEC Emerg Gen	1%	13%	4%	4%	4%	4%	--	--	--
KEC Fire Pump/PMEC Fire Pump	1%	14%	8%	8%	8%	8%	--	--	--
KEC Cooling Tower/PMEC PB Cool Tower	--	--	50%	--	--	--	--	50%	--
KEC Total/PMEC Total	22%	27%	30%	32%	32%	29%	29%	32%	0%

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Table 5-11 PMEC Emission Unit Modeling Release Parameters for Class I Analysis

Source	Type	X (km)[1]	Y (km)[1]	Elevation (m)[2]	Release Height (m)	Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)	Horiz. Std. Dev. (m)	Vertical Std. Dev. (m)
Combustion Turbine Generator 1 & 2	Stack	-139.343	-315.651	120.2	45.7	366.5	19.9	6.10		
Tank Vent Oxidizer	Stack	-139.291	-315.495	121.4	64.0	579.8	8.5	1.83		
Auxiliary Boiler	Stack	-139.356	-315.669	120.1	12.2	422.0	9.7	1.52		
Flare	Stack	-139.572	-315.374	124.6	30.5	1144.3	0.2 (8.0) [4]	15.24		
Ship Exhaust	Stack	-139.848	-315.943	121.2	35.1	622.0	50.2	0.41		
Rest of Sources [3]	Volume	-139.377	-315.622	120.8	15.9				156.1	9.5

1 Lambert conformal coordinates with an origin of 49N and 121W and standard latitudes of 30N and 60N.
2 Bilinear interpolated elevation from 4-km mesh size terrain file used in the CALPUFF simulations.
3 Combined volume source representing cooling towers, diesel engines and fugitive dust associated with materials handling.
4 Flaring in the startup and annual cases used an exit velocity of 8.0 m/s.

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Table 5-12 PMEC Predicted Class I Area and Area of Interest Criteria Pollutant Concentrations

Class I Area / Area of Interest	Maximum Predicted Concentration (µg/m3)								
	Normal Short-Term / Worst Case Annual Operation						Startup		
	NO_2	PM_{10}		SO_2			PM_{10}	SO_2	
	Annual	24-Hour	Annual	3-Hour	24-Hour	Annual	24-Hour	3-Hour	24-Hour
Alpine Lakes WA	0.0006	0.053	0.0015	0.0722	0.0129	0.0005	0.0674	0.089	0.0145
Glacier Peak WA	0.0002	0.0274	0.0006	0.034	0.0062	0.0002	0.0351	0.0372	0.0083
Goat Rocks WA	0.0011	0.0319	0.002	0.1247	0.0215	0.0007	0.0424	0.1191	0.0222
Mt. Adams WA	0.0021	0.0584	0.0052	0.2109	0.032	0.0018	0.0767	0.2225	0.035
Mt. Hood WA	0.0027	0.0683	0.006	0.2336	0.0389	0.0022	0.0936	0.2826	0.0437
Mt. Jefferson WA	0.0006	0.0539	0.0027	0.0864	0.0189	0.0007	0.0643	0.094	0.0207
Mt. Rainier NP	0.0016	0.0703	0.0023	0.257	0.0351	0.001	0.0976	0.2916	0.035
Mt. Washington WA	0.0002	0.0409	0.002	0.0442	0.0109	0.0004	0.052	0.046	0.0111
Olympic NP	0.0006	0.0439	0.0014	0.1241	0.0208	0.0005	0.0546	0.1507	0.0236
Three Sisters WA	0.0002	0.0456	0.002	0.0375	0.0105	0.0004	0.0592	0.0439	0.0125
CRGNSA [4]	0.0129	0.2025	0.0177	0.6061	0.1199	0.0083	0.2692	0.7125	0.1392
Maximum Concentration	*0.0129*	*0.2025*	*0.0177*	*0.6061*	*0.1199*	*0.0083*	0.2692	0.7125	0.1392
Class I Area Max. Conc. [4]	*0.0027*	*0.070*	*0.0060*	*0.2570*	*0.0389*	*0.0022*	*0.0976*	*0.2916*	*0.0437*
USEPA Proposed SIL[2]	*0.1*	*0.3*	*0.2*	*1*	*0.2*	*0.1*	*0.3*	*1*	*0.2*
FLM Recommended SIL[2]	*0.03*	*0.27*	*0.08*	*0.48*	*0.07*	*0.03*	*0.27*	*0.48*	*0.07*
Class I Area PSD Increment[3]	*2.5*	*8*	*4*	*25*	*5*	*2*	*8*	*25*	*5*

1 NO_X was conservatively assumed to be 100 percent converted to NO_2.
2 SIL = Significant Impact Level; USEPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.
3 PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v)
4 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

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Table 5-13 KEC Predicted Class I Area and Area of Interest Criteria Pollutant Concentrations

Class I Area / Area of Interest	Maximum Predicted Concentration (µg/m3)											
	Normal Short-Term / Worst Case Annual Operation								Startup			
	NO_2	PM_{10}		$PM_{2.5}$		SO_2			PM_{10}	$PM_{2.5}$	SO_2	
	Annual	24-Hour	Annual	24-Hour	Annual	3-Hour	24-Hour	Annual	24-Hour	24-Hour	3-Hour	24-Hour
Alpine Lakes WA	0.00016	0.0167	0.0004	0.0167	0.0004	0.0227	0.0040	0.0001	0.0191	0.0191	0.0162	0.0037
Glacier Peak WA	0.00005	0.0086	0.0002	0.0086	0.0002	0.0107	0.0019	0.0000	0.0099	0.0099	0.0068	0.0021
Goat Rocks WA	0.00030	0.0100	0.0006	0.0100	0.0006	0.0392	0.0067	0.0002	0.0120	0.0120	0.0217	0.0056
Mt. Adams WA	0.00057	0.0183	0.0015	0.0183	0.0015	0.0662	0.0100	0.0004	0.0217	0.0217	0.0405	0.0089
Mt. Hood WA	0.00074	0.0215	0.0018	0.0215	0.0018	0.0734	0.0121	0.0005	0.0265	0.0265	0.0515	0.0111
Mt. Jefferson WA	0.00016	0.0169	0.0008	0.0169	0.0008	0.0271	0.0059	0.0002	0.0182	0.0182	0.0171	0.0053
Mt. Rainier NP	0.00044	0.0221	0.0007	0.0221	0.0007	0.0807	0.0109	0.0002	0.0276	0.0276	0.0531	0.0089
Mt. Washington WA	0.00005	0.0129	0.0006	0.0129	0.0006	0.0139	0.0034	0.0001	0.0147	0.0147	0.0084	0.0028
Olympic NP	0.00016	0.0138	0.0004	0.0138	0.0004	0.0390	0.0065	0.0001	0.0155	0.0155	0.0275	0.0060
Three Sisters WA	0.00005	0.0143	0.0006	0.0143	0.0006	0.0118	0.0033	0.0001	0.0168	0.0168	0.0080	0.0032
CRGNSA [4]	0.00352	0.0636	0.0052	0.0636	0.0052	0.1904	0.0373	0.0019	0.0763	0.0763	0.1298	0.0353
Maximum Concentration	*0.0035*	*0.064*	*0.0052*	*0.064*	*0.0052*	*0.19*	*0.037*	*0.0019*	*0.0763*	*0.0763*	*0.130*	*0.0353*
Class I Area Max. Conc. [4]	*0.0007*	*0.0221*	*0.0018*	*0.0221*	*0.0018*	*0.0807*	*0.0121*	*0.0005*	*0.0276*	*0.0276*	*0.0531*	*0.0111*
USEPA Proposed SIL [2]	*0.1*	*0.3*	*0.2*	*0.07*	*0.06*	*1*	*0.2*	*0.1*	*0.3*	*0.07*	*1*	*0.2*
FLM Recommended SIL [2]	*0.03*	*0.27*	*0.08*	--	--	*0.48*	*0.07*	*0.03*	*0.27*	--	*0.48*	*0.07*
Class I Area PSD Increment [3]	*2.5*	*8*	*4*	--	--	*25*	*5*	*2*	*8*	--	*25*	*5*

1 NO_X was conservatively assumed to be 100 percent converted to NO_2.
2 SIL = Significant Impact Level; USEPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.
3 PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v)
4 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

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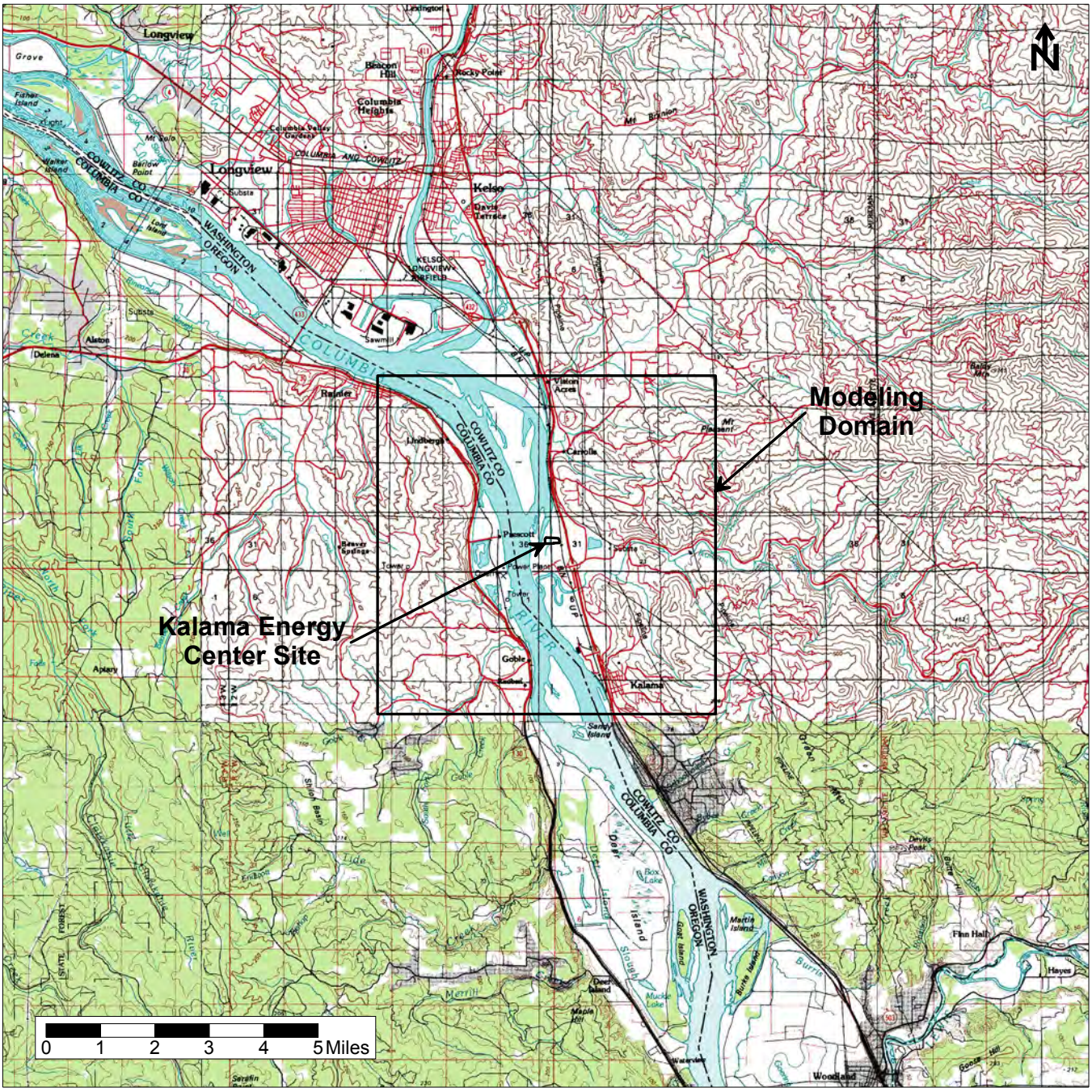

Figure 2-1 General Location of the Kalama Energy Center

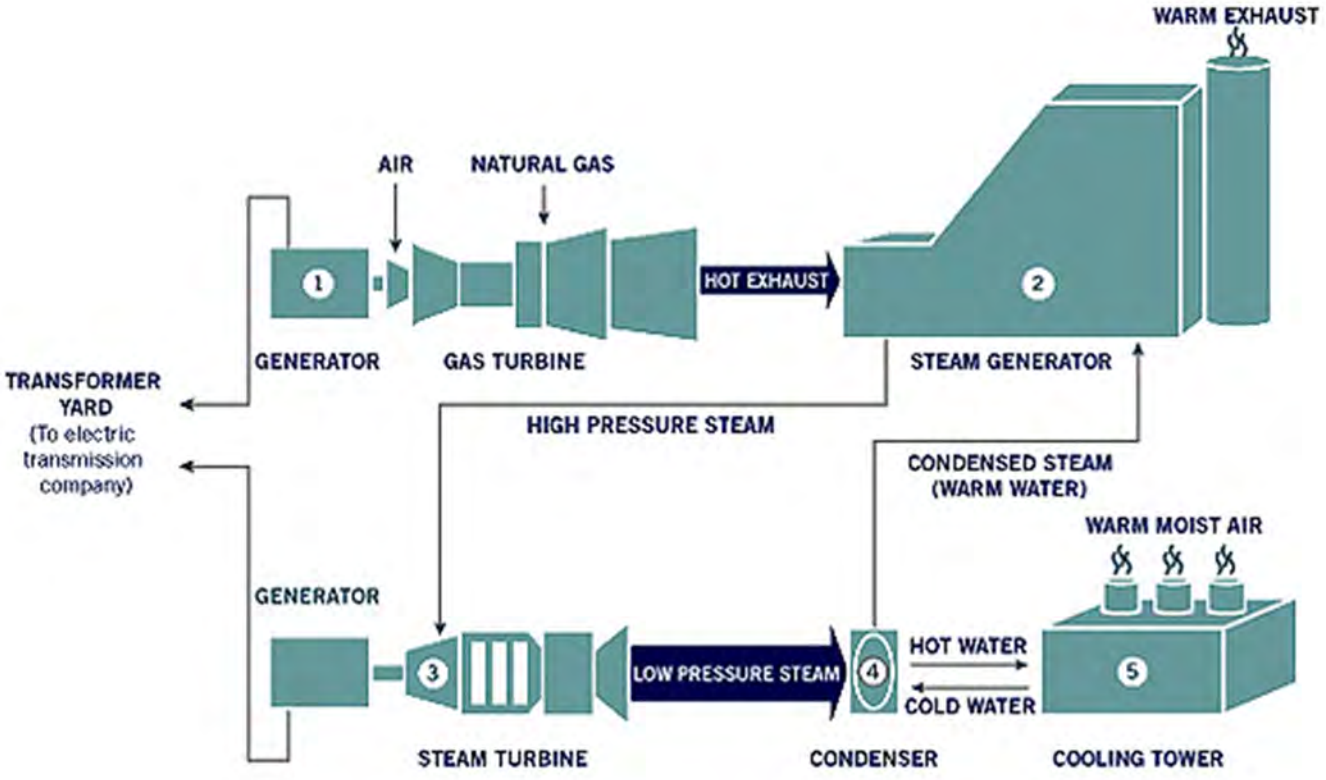

Figure 2-2 Power Generation Unit Schematic

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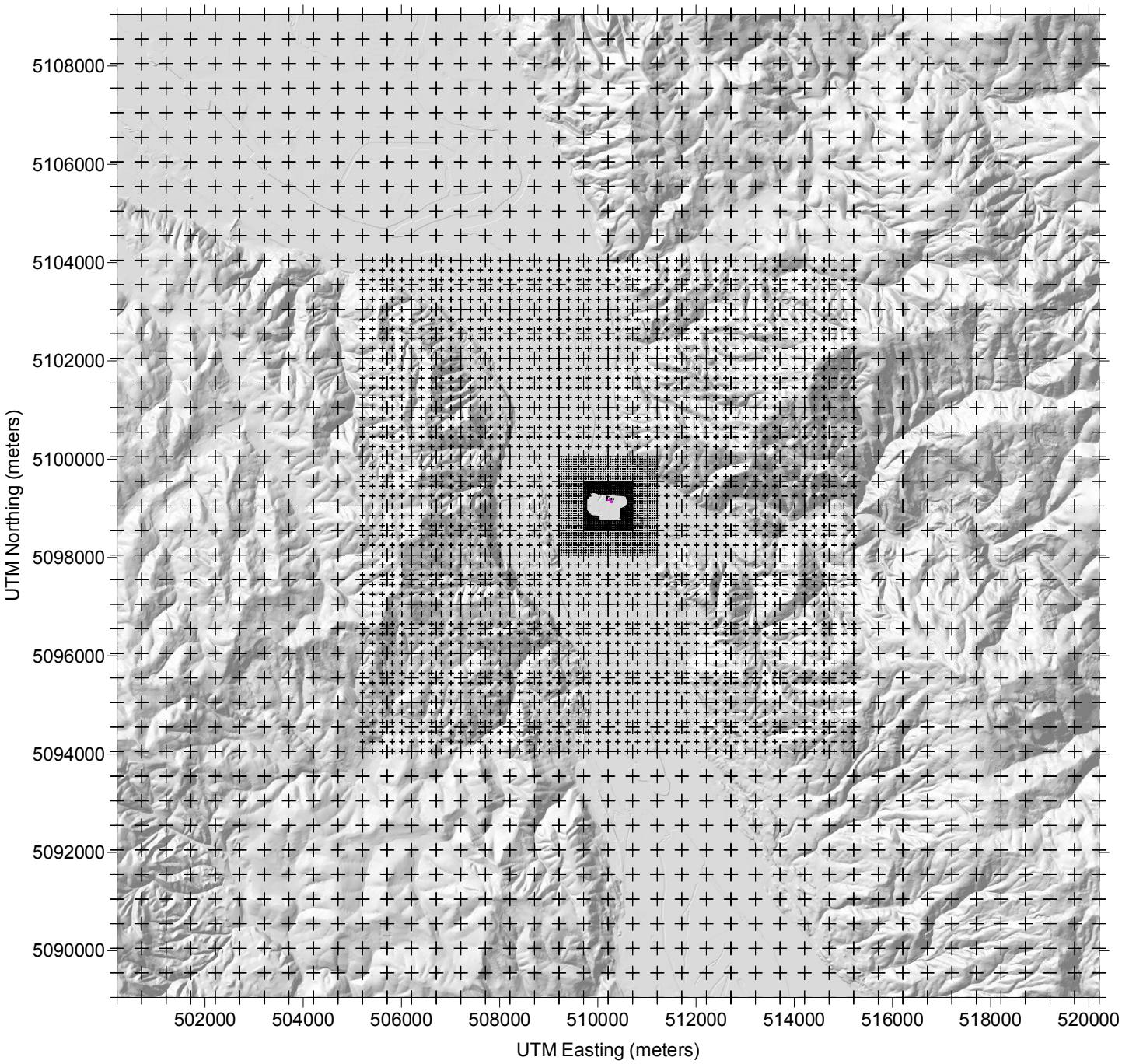

Figure 4-1 Modeling Receptor Locations

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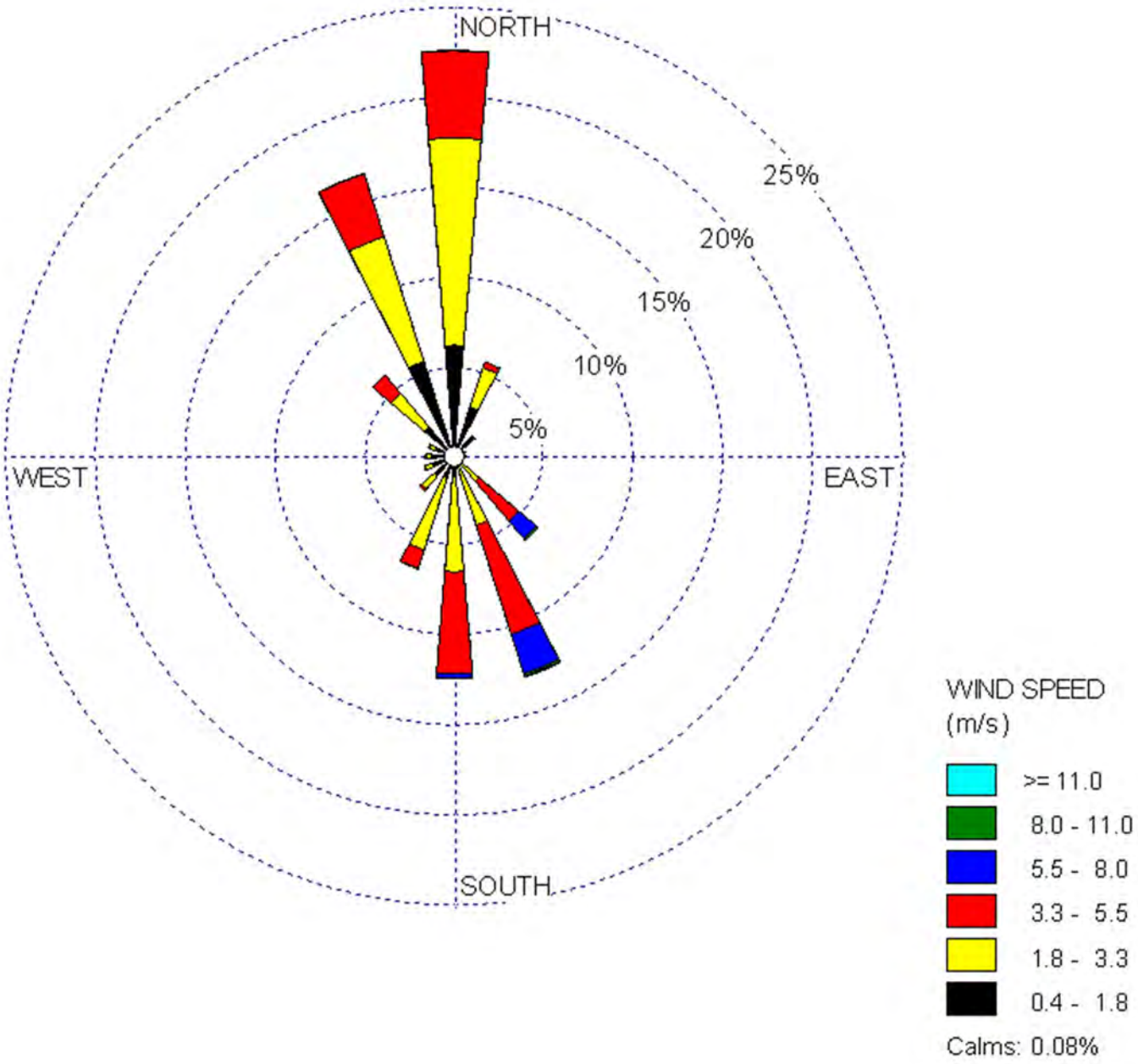

Figure 4-2 Meteorological Data Wind Rose – Jan. 1 to Dec. 31, 1995

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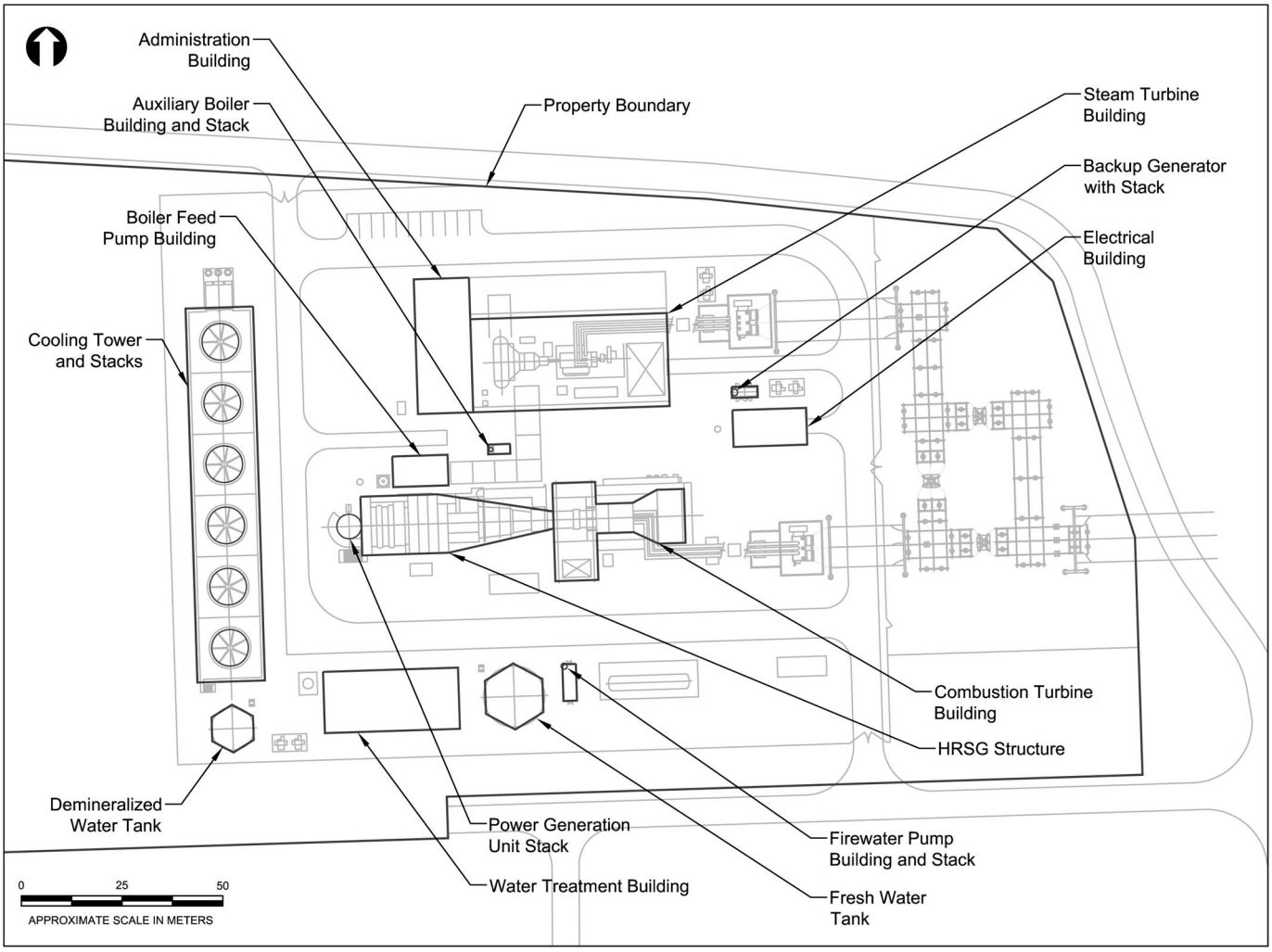

Figure 4-3 Locations of Significant Structures and Emission Units at Kalama Energy Center

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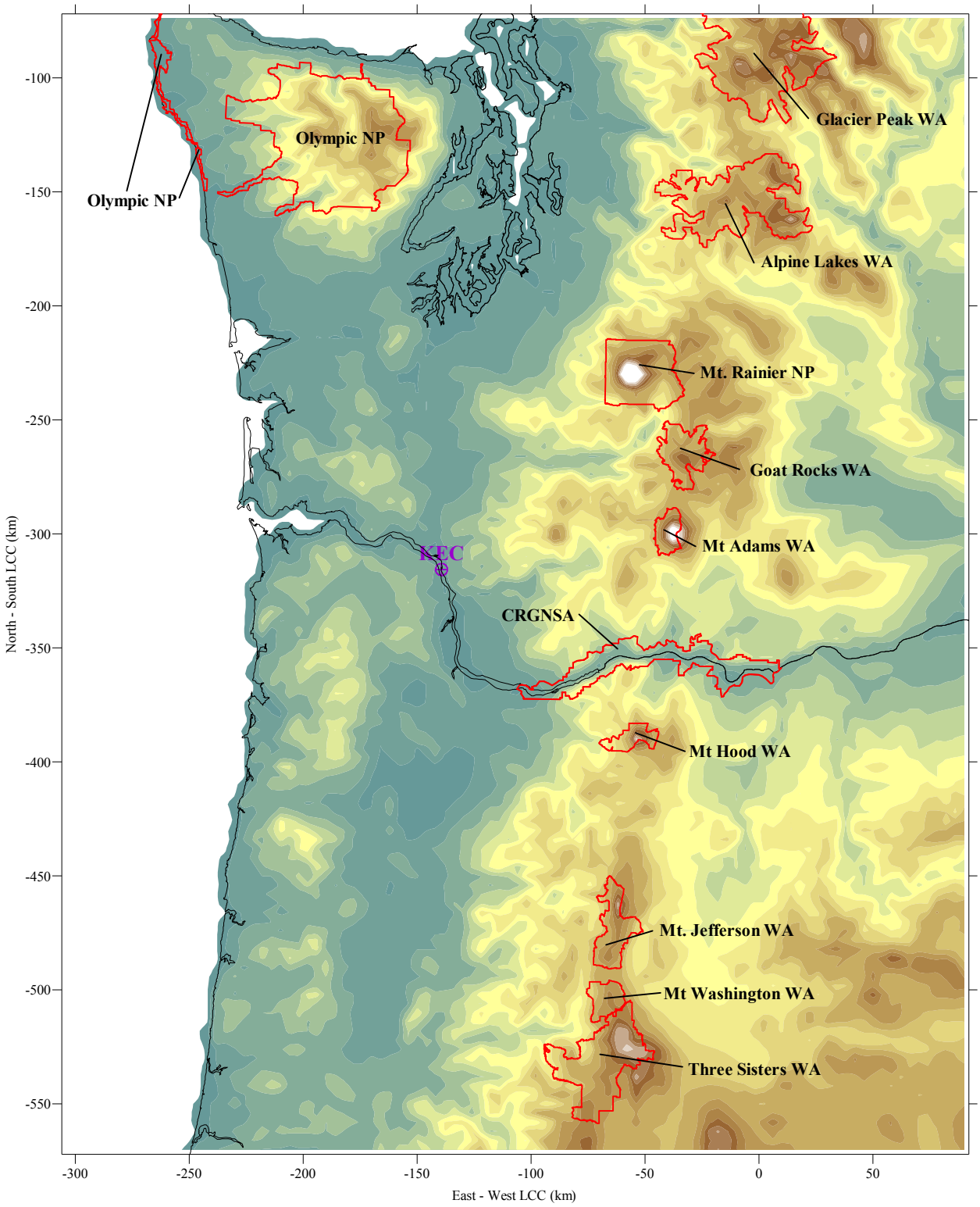

Figure 5-1 Locations of Class I Areas and CRGNSA

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Appendix A:
Air Pollutant Emission Rate Calculations

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Power Generation Unit Emission Rates

		Operating Scenario		
		100% Load w/DF	100% Load no DF	50% Load no DF
AMBIENT CONDITIONS				
Air temperature	°F	10	10	10
Air humidity	%	69	69	69
Air pressure	psia	14.68	14.68	14.68
Air pressure	kPa	101.22	101.22	101.22
Standard temperature	K	293.15	293.15	293.15
Standard pressure	kPa	101.33	101.33	101.33
Universal Gas Constant	kJ/(kmol*K)	8.314	8.314	8.314
OPERATING DATA				
Duct burner status / heat input level	%	100	off	off
Fuel LHV	Btu/lb	21,012	21,012	21,012
Fuel mass flow GT	lb/h	96,746	96,744	61,113
Fuel mass flow duct firing	lb/h	12,135	0	0
Fuel HHV	Btu/lb	23,126	23,126	23,126
Heat input GT (HHV)	MMBtu/hr	2,237	2,237	1,413
Heat input duct firing (HHV)	MMBtu/hr	281	0	0
Total heat input (HHV)	MMBtu/hr	2,518	2,237	1,413
GT EXHAUST GAS				
Stack exhaust gas mass flow	1000 lb/h	4,313	4,313	2,966
Stack exhaust gas mass flow (dry)	1000 lb/h	4,097	4,097	2,838
GT exhaust gas temperature	°F	1,093	1,093	1,128
Stack exhaust gas temperature	°F	167	182	166
Stack exhaust gas temperature	K	348	356	348
Gas constant	Btu/(lb °F)	0.07	0.07	0.07
N_2	mass-%	73.8	73.8	74.0
O_2	mass-%	13.9	13.9	15.1
CO_2	mass-%	6.1	6.1	5.3
H_2O	mass-%	5.0	5.0	4.3
Ar	mass-%	1.2	1.2	1.2
SO_2	mass-%	0.0	0.0	0.0
N_2	vol-%	75.0	75.0	75.4
O_2	vol-%	12.3	12.3	13.5
CO_2	vol-%	4.0	4.0	3.4
H_2O	vol-%	7.9	7.9	6.8
Ar	vol-%	0.9	0.9	0.9
SO_2	vol-%	0.0	0.0	0.0
Exhaust MW (wet)	kg/kmol	28.5	28.5	28.5
Exhaust MW (dry)	kg/kmol	29.4	29.4	29.3
Stack exhaust gas volume flow (dry, standard)	m3/hr @ 15% O2	2,199,922	1,954,696	1,234,778
Stack exhaust gas volume flow (wet, actual)	m3/hr (actual)	1,946,156	1,770,608	1,252,495
Stack exhaust gas volume flow (normal - wet, standard)	Nm3/hr	1,638,706	1,456,039	1,056,314
Stack exhaust gas volume flow (dry, standard)	dscfm @ 15% O2	1,294,825	1,150,490	726,763

EMISSION RATE CALCULATIONS				
NO_x emissions @ 15% O_2 dry	ppmvd	2.0	2.0	2.0
	lb/hr (calculated)	18.5	16.5	10.4
CO emissions @ 15% O_2 dry	ppmvd	2.0	2.0	2.0
	lb/hr (calculated)	11.3	10.0	6.3
VOC emissions @ 15% O_2 dry (as CH_4)	ppmvd	1.0	1.0	1.0
	lb/hr (calculated)	3.2	2.9	1.8
PM_{10} emissions	lb/MMBtu	0.00680	0.00680	0.00680
	lb/hr (calculated)	17.1	15.2	9.6
	gr/dscf	0.0015	0.0015	0.0015
$PM_{2.5}$ emissions	fraction of PM_{10}	1.00	1.00	1.00
	lb/hr (calculated)	17.12	15.21	9.61
SO_2 emissions	lb SO_2/MMBtu (1-hr avg)	0.0072	0.0072	0.007
	lb SO_2/MMBtu (24-hr avg)	0.0067	0.0067	0.007
	lb SO_2/MMBtu (ann avg)	0.0037	0.0037	0.004
	lb/hr (1-hr avg)	18.25	16.22	10.24
	lb/hr (24-hr avg)	16.83	14.95	9.45
	lb/hr (ann avg)	9.25	8.22	5.19
H_2SO_4 emissions	% of SO_2 converted	10%	10%	10%
	lb/hr (24-hr avg)	2.58	2.29	1.45
	lb/hr (ann avg)	1.42	1.26	0.79
NH_3 emissions @ 15% O2	ppmvd	5.00	5.00	5.00
	lb/hr	17.12	15.21	9.61

Natural Gas-Fired Auxiliary Boiler Emission Rates

Maximum heat input: 36.5 10^6 Btu/hr, HHV
596.4052 scf/min

Emission factors

Pollutant	Emission Factor (lb/MMBtu)	Basis
NO_X	0.0110	Low NO_X burner, BACT
CO	0.0370	Proper combustion, BACT
SO_2	0.00725	2.59 gr S/100 scf NG daily max plus 25% saftey factor
SO_2	0.00367	1.31 gr S/100 scf NG annual average plus 25% saftey factor
PM_{10}	0.0077	BACT
$PM_{2.5}$	0.0077	Assumed equal to PM_{10}, BACT
VOC	0.004	Proper combustion, BACT

Emission calulations

Averging Period	Units	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC
1-Hour	lb/hr	0.402	1.35	0.265	0.281	0.281	0.146
Annual[1]	tpy	0.879	2.96	0.294	0.615	0.615	0.320

[1] 50% capacity factor

Emergency Diesel-Fueled Generator Criteria Pollutant Emission Rates

	Units	NO_X[2]	CO	SO_2[3]	PM_{10}	$PM_{2.5}$	VOC
Emission Factor[1]	g/hp-hr	2.6	0.23	0.0055	0.024	0.024	0.03
	lb/hp-hr	0.0057	0.00051	0.000012	0.000053	0.000053	0.000066
Emission Rates	lb/hr	7.03	0.622	0.0149	0.0649	0.0649	0.0812
	tons/yr[4]	0.183	0.0162	0.000387	0.00169	0.00169	0.00211

[1] Emission factors were taken from a representative generator (Caterpillar Standby 800 ekW 1000 kVA Generator Set), except for NOx and SO_2

[2] NOx based on Tier 4 engine NOx emission requirement

[3] SO_2 based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.0015% by weight (8.09e-3 × %S)

[4] Maximum annual emission based on 52 hr/yr normal maintenance operation per engine.

Engine output:	1227	hp
Fuel sulfur:	0.0015	wt%
Hours per year	52	

Emergency Diesel-Fueled Fire Pump Engine Criteria Pollutant Emission Rates

	Units	NO_X	CO	SO_2[2]	PM_{10}	$PM_{2.5}$	VOC
Emission Factor[1]	g/hp-hr	2.56	0.597	0.0055	0.079	0.079	0.067
	lb/hp-hr	0.00564	0.00132	0.000012	0.00017	0.00017	0.00015
Emission Rates	lb/hr	1.35	0.316	0.00291	0.0418	0.0418	0.0354
	tons/yr[4]	0.0352	0.00821	0.0000757	0.001087	0.001087	0.00092

[1] Emission factors were taken from a representative fire pump engine (Clarke Model JU6H-UFADR0), except for SO_2

[2] SO_2 based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.05% by weight (8.09e-3 × %S)

[3] Maximum annual emission based on 52 hr/yr normal maintenance operation per engine.

Engine output:	240	hp
Fuel sulfur:	0.0015	wt%
Hours per year	52	

Cooling Tower PM Emission Rate

Parameter	Value	Basis
Water circulation rate, million lb/hr	73.47	Typical cooling tower design
Maximum dissolved solids, ppmw	2400	TDS of water supply and 12 cycles of concentration[1]
Drift, fraction of circulating water	0.0005%	BACT
$PM_{10}/PM_{2.5}$ emission rate, lb/hr	0.88	Calculated[2]
$PM_{10}/PM_{2.5}$ emission rate, ton/yr	3.86	Calculated[3]

[1] Maximum expected total dissolved solids (TDS) in makeup water = 200 parts per million by weight (ppmw); maximum expected TDS in circulating cooling water at twelve cycles = 12 x 200 = 2400 ppmw

[2] Example calculation: (73 x 10^6 lb/hr) x (0.000005 lb drift/lb) x (2400 lb PM/10^6 lb drift) = 0.88 lb/hr

[3] Based on continuous operation (8,760 hr/yr)

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Appendix B:
Best Available Control
Technology Analysis

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Best Available Control Technology Analysis for a Combined-Cycle Combustion Turbine Project

Kalama, Washington

Prepared for:
Kalama Energy Center
Kalama, Washington

On behalf of:
Energy Northwest
Richland, Washington

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
November 2011

Project Number:
29-24696A

ENVIRON

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1 Introduction

In Washington, Best Available Control Technology (BACT) is required for criteria and toxic air pollutant (TAP) emissions from new and modified industrial sources. The intent of this document is to present a BACT analysis for emission units associated with the proposed Kalama Energy Center (KEC) combined-cycle electrical generation facility.

1.1 Results and Summary

The proposed BACT controls and associated emission rates for each proposed emission unit are summarized in Table 1-1. Project sources addressed in this table include:

One Natural Gas-Fired, Combined-Cycle Combustion Turbine;

One 6-cell, Recirculating, Mechanical-draft Cooling Tower for the combined-cycle unit;

One Auxiliary Boiler; and

Two Diesel-Fueled Engines (one powering a back-up generator, and one powering an emergency fire water pump)

1.2 BACT Review Process

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs"*[1]

In a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation, the agency provided guidance on the "top-down" methodology for determining BACT. The "top-down" process involves the identification of all applicable control technologies according to control effectiveness. Evaluation begins with the "top," or most stringent, control alternative. If the most stringent option is shown to be technically or economically infeasible, or if environmental impacts are severe enough to preclude its use, then it is eliminated from consideration and then the next most stringent control technology is similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by technical or economic considerations, energy impacts, or environmental impacts. The top control alternative that is not eliminated in this process becomes the proposed BACT basis.

This top-down BACT analysis process can be considered to contain five basic steps described below:[2]

1 From 40 CFR 52.21(b)(12)

[2] "New Source Review Workshop Manual", DRAFT October 1990, EPA Office of Air Quality Planning and Standards

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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.

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a "top-down" manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the "maximum degree of emissions reduction." Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of "energy, environmental, and economic impacts" contained in the record of the permit decisions.

Additionally, the minimum control efficiency to be considered in a BACT analysis must result in an emission rate no less stringent than the applicable New Source Performance Standard (NSPS) emission rate, if any NSPS standard for that pollutant is applicable to the source.

This BACT analysis was conducted in a manner consistent with this stepwise approach. Control options for potential reductions in criteria pollution emissions were identified for each source. These options were identified by researching the EPA database known as the RACT/BACT/LAER Clearinghouse (RBLC), drawing upon previous environmental permitting experience for similar units and surveying available literature. Available controls that are judged to be technically feasible are further evaluated based on an analysis of economic, environmental, and energy impacts.

Assessing the technical feasibility of emission control alternatives is discussed in EPA's draft "New Source Review Workshop Manual." Using terminology from this manual, if a control technology has been "demonstrated" successfully for the type of emission unit under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. An available technology is one that is commercially available; meaning that it has advanced through the following steps:

Concept stage;

Research and patenting;

Bench scale or laboratory testing;

Pilot scale testing;

Licensing and commercial demonstration; and

Commercial sales.

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Suitability for consideration as a BACT measure involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission unit), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission unit may not be applicable to a similar unit, depending on differences in the gas streams' physical and chemical characteristics.

1.3 Particulate Matter Size Classifications

This BACT analysis assumes that PM, PM_{10}, and $PM_{2.5}$ emissions are equivalent for all emission units. The control technologies, emission factors, and proposed BACT described in the analysis apply to PM, PM_{10}, and $PM_{2.5}$.

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2 Power Generation Unit BACT Analysis

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the power generation unit proposed for the KEC to determine appropriate BACT emission limits. This BACT analysis is based on the current state of emissions control technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

2.1 Process Description

The proposed power generation unit will consist of a natural gas-fired combined cycle (NGCC) combustion turbine, which is a combustion turbine paired with a heat recovery steam generator (HRSG) that will include supplemental heating (i.e., a "duct burner"). Steam from the HRSG will be sent to a steam turbine that will turn a power generator. The combustion turbine as well as the duct burner will be fueled exclusively by pipeline quality natural gas. Pollutant emissions from the power generation unit will include oxides of nitrogen (NO_X), particulate matter with an aerodynamic diameter greater than ten microns (PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), and volatile organic compounds (VOCs).

2.2 Commercially Available Control Technologies

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations. Table 2-1 lists a number of recent BACT determinations in recent years for projects that included an NGCC combustion turbine.

The RBLC database survey results indicate that available BACT options for the pollutants emitted from the power generation unit include:

- Low-NO_X Burners (LNBs)
- XONON
- Selective Catalytic Reduction (SCR)
- EMx
- Selective Non-Catalytic Reduction (SNCR)
- Good Combustion Practices (GCPs)
- Oxidation Catalysts
- Low sulfur fuels
- Flue Gas Desulfurization (FGD)

2.3 NO_X BACT

NO_X is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_X), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_X). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular

nitrogen is present. Therefore, it is expected that essentially all NO_X emissions from the power generation unit will originate as thermal NO_X.

A natural gas-fired combustion turbine is an inherently low-emitting process. The unit proposed for the KEC can nominally achieve a NO_X emission factor of 0.06 pounds per million British thermal unit (lb/MMBtu) without any post-combustion controls (i.e., without SCR). The remainder of this analysis considers the use of this lower-emitting process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbine and the HRSG.

The rate of formation of thermal NO_X in an NGCC combustion turbine is a function of residence time, oxygen radicals, and peak flame temperature. Front-end NO_X control techniques are aimed at controlling one or more of these variables during combustion. Examples include diluent injection (e.g., steam) and dry low-NO_X burners. Post-combustion controls (e.g., SCR) seek to convert NO_X formed during combustion to nitrogen and water using a reductant injected into the exhaust. These technologies are considered to be commercially available pollution prevention techniques.

2.3.1 Identify Control Technologies

Possible control technologies for the proposed turbines were identified by examination of previously issued permits and through RBLC queries for facilities that include NGCC combustion turbines. Table 2-1 summarizes the NO_X control technologies and permit limits for NGCC combustion turbines similar to those proposed for the KEC. For this top-down analysis, all of the following technologies were considered to be potentially available for use with the proposed NGCC combustion turbine:

<u>Combustion Process Controls</u>

LNBs

XONON

<u>Post-Combustion Controls</u>

SCR

EMx

SNCR

2.3.2 Evaluate Technical Feasibility

Each identified technology is first examined to determine if it is technically feasible to control NO_X emissions from natural gas-fired combustion turbines. First, controls potentially achieved by modifications to the combustion process itself are considered. Next, potential control methods utilizing add-on control equipment, such as SCR, to remove NO_X from the exhaust gas stream after its formation during combustion are examined.

<u>Dry Low-NO_X Burners</u>

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Low-NO_X Burners (LNBs) burners control NO_X formation in NGCC combustion turbines by staged combustion of the natural gas. This is done by designing the burners to control both the stoichiometry and temperature of combustion by tuning the fuel and air locally within each individual burner's flame envelope. Burner design includes features that regulate the aerodynamic distribution and mixing of the fuel and air. A lean, pre-mixed burner design mixes the fuel and air prior to combustion. This results in a homogeneous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_X emissions. A lean fuel-to-air ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower the combustion temperature, which in turn lowers thermal NO_X formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment. LNBs are a technically feasible control option for this unit, and, at this point, are considered a baseline level of control for all NGCC combustion turbine projects.

<u>XONON</u>

XONON is a technology developed by Catalytica Combustion Systems to lower the temperatures in conventional combustion turbine combustors, and, therefore, reduce NO_X formation. However, XONON has been demonstrated only on smaller combustion turbines (i.e., 1.5 MW), and has not yet been scaled up for use on larger combustion turbines such as the GE 7FA or Siemens STG6-5000F. As a result, XONON is not considered technically feasible for use on the proposed NGCC combustion turbine, and is eliminated from further consideration as BACT.

<u>SCR</u>

SCR is a technology that achieves post-combustion reduction of NO_X from flue gas within a catalytic reactor. The SCR process involves the injection of ammonia (NH_3) into the exhaust gas stream upstream of a specialized catalyst module, promoting conversion of NO_X to molecular nitrogen. The hardware of an SCR system is composed of an ammonia storage tank, an injection grid (system of nozzles that spray NH_3 into the exhaust gas ductwork), a structured, fixed-bed catalyst module, and electronic controls. SCR systems are commonly employed to reduce NO_X emissions from NGCC combustion turbines.

In the SCR process, NH_3, usually diluted with air or steam, is injected through a grid system into the exhaust gas upstream of the catalyst bed. On the catalyst surface, the NH_3 reacts with NO_X to form molecular nitrogen and water. The basic reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_X decomposition to occur. In a natural gas-fired turbine, NO_X removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Compounds such as sulfur and certain metals, if

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present in the exhaust gas stream, can "poison" the catalyst, impacting catalyst activity, inhibiting conversion efficiency, and reducing the useful life of the catalyst.

EMx

The EMx (formerly SCONOx) system is an add-on control device that reduces emissions of multiple pollutants. EMx control technology is provided by Emerachem, LLC (formerly Goal Line Environmental Technologies). EMx utilizes a single catalyst for the reduction of CO, VOC and NOx, which are converted to CO_2, H_2O and N_2. The system does not use NH_3 and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EMx requires natural gas, water, steam, electricity and ambient air, and no special reagent chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

There are currently several EMx units in commercial installations worldwide, although all are applied to emission units that are much smaller than those proposed for the KEC. The original application of EMx was at the Federal Plant in Vernon, California owned by Sunlaw Cogeneration. This installation was on a GE LM2500, an approximately 34 MW combined cycle system, which has had an operating EMx system since December 1996. That system has undergone many changes over the years. The second commissioning of a EMx system was at the Genetics Institute in Massachusetts on a 5 MW Solar Turbine Taurus 50 Model. This facility has reported problems with meeting permitted NOx levels of 2.5 ppm, and subsequently received a permit modification extending the EMx demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan combustion turbines at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

There is no current working experience of EMx on large combustion turbine units such as those proposed for the KEC. EMx was considered at some larger applications including a 250 MW unit at the La Paloma plant near Bakersfield, and a 510 MW plant in Otay Mesa. However, the La Paloma and Otay Mesa projects were given the alternative to install SCR and now plan to do so. In evaluating technical feasibility for large NGCC power stations, additional concerns include the following:

EMx uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed NGCC units are significantly larger than the much smaller facilities where EMx has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the proposed combustion turbines.

The EMx catalyst is very susceptible to poisoning by sulfur compounds. Because pipeline natural gas contains some sulfur, a separate catalyst system or filter may be required to absorb SO_2 before it could contact the catalyst bed. However, operation of such an SO_2 absorbtion system on a combustion turbine is not proven, and, upon regeneration, the process would create an H_2S stream requiring treatment.

EMx would not be expected to achieve lower guaranteed NO_X levels than SCR, and, for reasons described above, it has greater feasibility concerns than SCR for application on large NGCC combustion turbines.

Although application of an EMx system to a large-scale NGCC combustion turbine has not be demonstrated in practice, it must be considered technically feasible for such an application. However, the high capital and operating costs of the EMx system make it not cost effective when compared to an SCR system capable of achieving similar emission rates. This cost-effectivenss determination was proposed for both the Cherry Point Cogeneration Project Electric Generating Facility and the Sumas Energy 2 Generation Facility and accepted by the Washington Energy Site Evaluation Council (EFSEC) and the Washington State Department of Ecology (Ecology). Because the economics associated with applying an EMx system to the KEC project are substantially the same as those presented for the Cherry Point and Sumas Energy 2 projects, the cost-effectiveness analysis in not repeated here.

SNCR

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_X control technology in which a reagent (anhydrous NH_3 or urea) is injected into the exhaust gases to react chemically with NO_X, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas. This must occur within a zone of the exhaust stream where the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. In order to achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X and the NH_3 discharge from the stack (known as “ammonia slip”) will be very high.

This technology is occasionally used in heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been used in combustion turbine applications to control NO_X, primarily because there are no flue gas locations within the combustion turbine or upstream of the HRSG with the requisite temperature and residence time characteristics to facilitate the SNCR flue gas reactions. Because of the incompatibility of the exhaust temperature with the SNCR operating regime, this technology is considered to be technically infeasible and is removed from further consideration as BACT.

2.3.3 Rank Control Technologies

Among the control technologies considered in the previous subsection, only the use of low-NO_X combustors and installation of an SCR system were considered both technically feasible and cost-effective to reduce NO_X emissions from the NGCC combustion turbine, and LNBs are considered the baseline NO_X control technology.

2.3.4 Evaluate Control Options

The next step in a BACT analysis is to conduct an analysis of the energy, environmental and economic impacts associated with each feasible control technology. Based on the evaluation in

the previous step, the only technically feasible and commercially proven technology suitable for establishment of BACT limits is an SCR system. The most notable environmental impact associated with this NO_X control technology is NH_3 emissions associated with use of NH_3 as the reagent chemical. The unreacted portion of the NH_3 passes through the catalyst and is emitted from the stack. These emissions are referred to as "ammonia slip," and their magnitude depends on the catalyst activity and the degree of NO_X control desired.

Economic and energy impacts associated with application of an SCR system are a decrease in the net power output of the units due to the increased pressure drop across the catalyst bed, the ongoing ammonia procurement and storage requirements, and increased maintenance costs associated with the accumulation of ammonia salts on the HRSG and the eventual de-activation of the catalyst. Because SCR has long been considered BACT for large NGCC combustion turbine units, the environmental, economic, and energy impacts have generally been deemed acceptable by USEPA and Ecology.

2.3.5 Select Control Technologies

The final step in the top-down BACT analysis process is to select BACT based on the results of the previous steps. Energy Northwest (ENW) proposes that the use of LNBs and installation of an SCR system to reduce NO_X exhaust gas concentration to 2 ppmv NO_X at 15 percent O_2 (3-hour average) be considered BACT for the KEC NGCC combustion turbine.

2.4 CO BACT

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. These control factors, however, can also tend to result in increased emissions of NO_X. Conversely, a lower NO_X emission rate achieved through flame temperature control (by diluent injection or dry lean pre-mix) may result in higher levels of CO emissions. Thus, a compromise must be established, whereby the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation.

2.4.1 Identify Control Technologies

Three technologies were identified as potentially applicable to the proposed NGCC combustion turbine for control of CO emissions:

<u>Combustion Process Controls</u>

Good Combustion Practices (GCPs)

<u>Post-Combustion Controls</u>

EMx

Oxidation Catalyst

2.4.2 Evaluate Technical Feasibility

Each identified technology was evaluated in terms of its technical feasibility for application to NGCC combustion turbines.

Good Combustion Practices

GCPs include operational and combustor design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. Such control practices applied to the proposed NGCC combustion turbine can achieve CO emission levels of 15 ppm during steady state, full load operation. At lower loads (50-70 percent), the combustion efficiency drops off notably, and CO emissions would be higher. GCPs are a technically feasible method of controlling CO emissions from the proposed NGCC combustion turbine, and are considered the baseline control technology.

EMx

The EMx system was described in the BACT analysis for control of NO_X emissions from NGCC combustion turbines. It is commercially available for small combustion turbines for controlling CO and can reduce emissions by up to 95 percent. As discussed in the NO_X BACT discussion however, it is not commercially available for large combustion turbines (i.e., the one proposed for the KEC). Furthermore, several recent BACT analyses for combustion turbine projects have determined that EMx is not a cost effective control technology, despite its alleged ability to control multiple pollutants.

Oxidation Catalysts

Catalytic oxidation is a post-combustion technology, which does not rely on the introduction of additional chemical reagents to promote the desired reactions. The oxidation of CO to CO_2 utilizes excess air present in the combustion turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. The catalyst oxidizes CO to CO_2, and VOCs to CO_2 and H_2O, but also can promote other oxidation reactions such as NH_3 to NO_X and SO_2 to SO_3. Consequently, the presence of a CO catalyst can cause emissions of other pollutants to increase, and therefore its design needs to be carefully considered.

Oxidation catalyst systems typically operate at temperatures between 750 to 1,100°F (400 to 600°C), and increased operating temperatures within that range generally result in more effective oxidation reactions. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90 percent, and typical VOC conversion efficiencies are 40 to 50 percent.[3]

3 "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production", California Air Resources Board, http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

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This technology has been required CO control equipment in a significant number of permits for NGCC combustion turbine projects, and is considered technically feasible for application to an NGCC combustion turbine.

2.4.3 Rank Control Technologies

GCPs and oxidation catalysts were found to be technically feasible for the proposed NGCC combustion turbine. GCPs are the baseline control technology, and oxidation catalyst systems are considered to be more effective. In practice, GCPs are always used, and an oxidation catalyst system would be used in addition to, not in place of, GCPs.

2.4.4 Select Control Technologies

The use of GCPs in conjunction with an oxidation catalyst system is proposed to be BACT for control of CO from NGCC combustion turbines. ENW proposes that the CO BACT-based limit for the KEC NGCC combustion turbine should be 2 ppmvd at 15 percent O_2 on a 3-hour average during non-startup operation.

2.5 VOC BACT

VOCs are a product of incomplete combustion of the natural gas fuel. Reduction of VOC emissions is accomplished by providing adequate fuel residence time and high temperature in the combustion zone to ensure complete combustion. The primary technologies identified for reducing VOC emissions from NGCC combustion turbines are oxidation catalysts and GCPs. A survey of the RBLC database indicated that good combustion control and burning clean fuel are the VOC control technologies primarily determined to be BACT.

2.5.1 Identify Control Technologies

Two technologies were identified as potentially applicable to the proposed NGCC combustion turbine for control of VOC emissions:

<u>Combustion Process Controls</u>

GCPs

<u>Post-Combustion Controls</u>

Oxidation Catalysts

2.5.2 Evaluate Technical Feasibility

<u>Good Combustion Practices</u>

GCPs applied to the proposed NGCC combustion turbine can achieve VOC emission levels below 3 ppmvd (at 15 percent O_2) based on data provided by Siemens. GCPs include operational and design elements to control the amount and distribution of excess air in the flue gas in order to ensure that enough oxygen is present for complete combustion. This technology is commonly applied to NGCC combustion turbines, is considered technically feasible, and is considered the baseline control technology for VOC emissions.

<u>Oxidation Catalyst</u>

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As discussed in Section 2.4.2, catalytic oxidation is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC as well as CO, reducing emissions of both. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing upwards of 90 percent control for CO. It is also worth noting that a typical additional incentive to using an oxidation catalyst, when feasible, is the incidental control of organic hazardous air pollutants (HAPs). Oxidation catalyst systems are considered technically feasible for controlling VOC emissions from an NGCC combustion turbine.

2.5.3 Select Control Technology

Catalytic oxidation in conjunction with GCPs is proposed as BACT for VOCs emitted by an NGCC combustion turbine. These practices will meet a VOC emission limit of approximately 1 ppmvd at 15 percent O_2 in the stack gases at loads greater than 50 percent.

2.6 PM BACT

Particulate matter (PM) emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filter and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low PM emissions.

The EPA has indicated that PM control devices are not typically installed on combustion turbines and that the cost of installing such control devices is prohibitive.[4] When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for PM control of stationary gas turbines have not been proposed or promulgated at a federal level.

Post combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial combustion turbines burning gaseous fuels. Therefore, the use of ESPs and baghouses is considered technically infeasible.

In the absence of add-on controls, the most effective control method demonstrated for gas-fired combustion turbines is the use of low ash fuel, such as natural gas. Use of GCPs and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

The use of pipeline natural gas and good combustion control is proposed as BACT for $PM/PM_{10}/PM_{2.5}$ control in the proposed KEC NGCC combustion turbine. These operational controls will limit combined filterable and condensable PM_{10} emissions to 17.8 pounds per hour (lb/hr), based on an emission factor of 0.0068 lb/MMBtu.

4 "Supporting Material for BACT Review for Large Gas Turbines used in Electrical Power Production", California Air Resources Board, http://www.arb.ca.gov/energy/powerpl/appcfin.pdf

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2.7 SO_2 and Sulfuric Acid BACT

2.7.1 Identify Control Technologies

SO_2 emissions from any combustion process are largely defined by the sulfur content of the fuel being combusted and the rate of the fuel usage. The combustion of natural gas in an NGCC combustion turbine creates primarily SO_2 and small amounts of sulfite (SO_3) by the oxidation of the fuel sulfur. The SO_3 can react with the moisture in the exhaust to form sulfuric acid mist, or H_2SO_4. Emissions of these sulfur species can be controlled by limiting the sulfur content of the fuel (pre-combustion control) or by scrubbing the SO_2 from the exhaust gas (post-combustion control). Potentially available control technologies include:

<u>Pre-Combustion Process Controls</u>

Use of low-sulfur fuel

<u>Post-Combustion Controls</u>

Flue Gas Desulfurization (FGD)

<u>Use of Low-Sulfur Fuel</u>

Natural gas contains sulfur as hydrogen sulfide (H_2S), carbonyl sulfide (COS), dimethyl sulfide (DMS), and various mercaptans, but at extremely low concentrations. Natural gas is generally considered a low-sulfur fuel, and on-site treatment to remove additional sulfur, while technically feasible, would not be cost-effective.

<u>Flue Gas Desulfurization</u>

Typical FGD processes operate by contacting the exhaust gas downstream of the combustion zone with an alkaline slurry or solution that absorbs and subsequently reacts with the acidic SO_2. FGD technologies may be wet, semi-dry, or dry based on the state of the reagent as it is injected or pumped into the absorber vessel. Also, the reagent may be regenerable (where it is treated and reused) or non-regenerable (all waste streams are de-watered and either discarded or sold). Wet, calcium-based processes, which use lime (CaO) or limestone ($CaCO_3$) as the alkaline reagent, are the most common FGD systems in PC unit applications. After the exhaust gas has been scrubbed, it is passed through a mist eliminator and exhausted to the atmosphere through a stack

FGD systems are commonly employed in conventional pulverized coal plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal.

2.7.2 Evaluate Technical Feasibility

The use of an FGD system to control SO_2 emissions from an NGCC combustion turbine is technically feasible in theory, but infeasible in practice. The pressure drop introduced by the FGD system could not be overcome by the combustion turbine without the addition of an induced draft fan, which would cause problems with the air/fuel mixture in the combustion

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turbine combustor. As a result, FGD technology is considered technically infeasible for controlling SO_2 emissions from an NGCC combustion turbine.

2.7.3 Select Control Technology

The applicant proposes that BACT for control of SO_2 emissions from the proposed NGCC combustion turbine be defined as treatment of the use of pipeline natural gas, which is considered a low-sulfur fuel.

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3 Auxiliary Boiler BACT Analysis

3.1 Process Description

One auxiliary boiler will serve the KEC power generation unit by providing steam for pre-startup equipment heating, as well as other miscellaneous services when steam is not available from the HRSG. The auxiliary boiler will produce a maximum of about 30,000 lb/hr of steam and will be fueled only by pipeline quality natural gas.

Pollutant emissions from natural gas boiler units include NO_X, PM_{10}, CO, SO_2, and VOCs. Annual operation of the boiler will be equivalent to or less than 50 percent of the year at maximum capacity.

3.2 Commercially Available Control Technologies

Review of the federal RBLC database and selected state permit information indicates that several technologies have been identified in BACT determinations. Table 3-1 lists a number of recent BACT determinations in recent years for auxiliary and industrial boiler equipment. The RBLC database survey results indicate that available BACT options for the pollutants emitted from auxiliary boilers include:

Good Combustion Practices

Staged Air/Fuel Combustion or Overfire Air Injection (OFA)

Low-NO_X burners (LNB)

Ultra-Low-NO_X burners (ULNB)

Oxidation Catalysts

Flue Gas Recirculation (FGR)

Selective Catalytic Reduction (SCR)

Low sulfur fuels

3.3 NO_X BACT

Several combustion and post-combustion controls are commercially available for the auxiliary boiler. These controls include staged air/fuel combustion, low-NO_X burners, flue gas recirculation, and SCR. The range of BACT NO_X emission limits for recently permitted auxiliary boilers (since 2004) is from 0.011 lb/MMBtu to 0.37 lb/MMBtu.

3.3.1 Ranking of Available Control Technologies

The identified control technologies are considered technically feasible for gaseous fuel fired boilers. Consequently, these controls will be ranked and evaluated for each pollutant for which BACT is required. In top-down order of decreasing stringency, the feasible NO_X controls are listed with the approximate level of emission reduction afforded by each technology:

Low-NO_X Burners with SCR	0.011 lb/MMBtu
Ultra-Low-NO_X Burners	0.011 lb/MMBtu

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Low-NO_X Burners with FGR	0.020 lb/MMBtu
Low-NO_X Burners with GCP	0.036 lb/MMBtu
FGR Alone	0.20 lb/MMBtu
Staged air/fuel or OFA	0.25 lb/MMBtu
GCP, Conventional Burners	0.40 lb/MMBtu

3.3.2 Proposed BACT Limits and Control Option

Energy Northwest proposes BACT for NO_X emissions from the natural gas-fired auxiliary boiler be GCP with Ultra-Low-NO_X burners. Boiler vendor information indicates that the hourly emissions for this unit with these technologies will be about 0.011 lb/MMBtu NO_X (equivalent to approximately 9 ppmvd at 3 percent O_2) at loads greater than 75 percent. This rate, or a corresponding lb/hour emission rate, is proposed as the BACT NO_X limit for emissions from the auxiliary boiler.

3.4 CO BACT

Only one post-combustion control is commercially available for the auxiliary boiler. This control is the implementation of an oxidation catalyst module. Based on the RBLC review presented in Table 3-1, the range of BACT CO emission limits for recently permitted auxiliary boilers (since 2004) is from 0.037 lb/MMBtu to 0.08 lb/MMBtu. BACT for CO on most units is GCP.

3.4.1 Ranking of Available Control Technologies

The identified control technologies, GCP and oxidation catalyst, are considered technically feasible for gaseous fuel fired boilers. In top-down order of decreasing stringency, the feasible CO controls are listed with the approximate level of control that could be achieved:

Oxidation Catalyst and GCP	0.0037 lb/MMBtu
GCP	0.037 lb/MMBtu (BACT baseline)

3.4.2 Consideration of Energy, Environmental and Cost Factors

The use of oxidation catalyst modules as add-on emission control is available and technically feasible for reduction in CO emissions from auxiliary boilers. These are in addition to combustion controls, namely GCP in combination with Low-NO_X burners.

With respect to energy factors, add-on post-combustion controls on an auxiliary boiler of this capacity range will noticeably reduce the thermal efficiency of the unit. Catalyst modules increase the back-pressure downstream of the combustion chamber by several tenths of an inch of water, depending upon design. Environmental factors associated with post-combustion catalytic systems have affected many recent boiler installations. Generally, these involve the effects of spent catalyst module disposal.

Prohibitively high annualized cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. Since the boiler is not continuously operated, but rather used during relatively infrequent start-up cycles, the emissions abated can be shown to not warrant

the investment in capital and operating costs. An annualized cost analysis for the proposed auxiliary boiler is provided to demonstrate this cost barrier.

The add-on CO control technology for the auxiliary boiler would be cost prohibitive in terms of cost per ton abated. The implementation of a catalytic oxidizer module has an estimated annualized cost of nearly $75,000, and provides a reduction of 2.92 tons per year, compared with the baseline option of GCP. From these results, the cost effectiveness of the catalytic oxidizer option is conservatively estimated to be not less than $25,000 per ton.

3.4.3 Proposed BACT Limits and Control Option

As illustrated in Table 3-2, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks, leads to the proposed BACT option of GCP for CO emissions. Energy Northwest proposes that BACT for CO from the auxiliary boiler is 0.037 lb/MMBtu (approximately 50 ppmvd), 3-hour average.

3.5 SO_2, VOC, and PM BACT

3.5.1 Ranking of Available Control Technologies

For these pollutants, the commercially available control measures that are identified in the most-stringent BACT determinations are use of low-sulfur, pipeline quality natural gas, and GCP. Based on review of the RBLC database in Table 3-1, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

SO_2 – 0.0006 lb/MMBtu to 0.082 lb/MMBtu

VOC – 0.0044 lb/MMBtu to 0.0054 lb/MMBtu

PM – 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

The two most-stringent available technologies are to be adopted for the auxiliary boiler, so further evaluation is unnecessary.

3.5.2 Proposed BACT Limits and Control Option

The limited operating period for the auxiliary boiler results in relatively low annual emissions of SO_2, VOC and PM_{10}, meaning that investment in add-on controls would not be cost effective even if they were feasible. Therefore, the use of pipeline natural gas and GCP are proposed as BACT for the auxiliary boiler, and no emission rates are proposed as BACT limits for SO_2, VOCs, and PM_{10}. Mass balance calculations based on the sulfur content of the expected source of natural gas indicates the SO_2 emission factor will be approximately 0.0054 lb/MMBtu, based on a 24-hour average. Boiler vendor information indicates that hourly average VOC and PM_{10} emission factors will be 0.004 lb/MMBtu and 0.005 lb/MMBtu, respectively.

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4 Cooling Tower BACT Analysis

4.1 Process Description

The proposed cooling system at the proposed facility consists of a circulating water system that will utilize a 6-cell mechanical draft cooling tower to support operations of the steam turbine generator. Wet (evaporative) cooling towers emit aqueous aerosol "drift" particles that evaporate to leave crystallized solid particles that are considered PM_{10} emissions. The proposed control technology for PM_{10} is high-efficiency drift eliminators to capture drift aerosols upstream of the release point to the atmosphere.

4.2 Commercially Available Control Technologies

Electrical generating facilities, refineries, and other large chemical processing plants utilize wet mechanical draft cooling towers for heat rejection. This portion of the proposed facility can be viewed as substantially similar to such processes.

Review of the federal RBLC database for large-scale cooling towers indicates that high efficiency drift eliminators and limits on total dissolved solids (TDS) concentration in the circulating water are the techniques which set the basis for cooling tower BACT emission limits. The efficiency of drift eliminator designs is characterized by the percentage of the circulating water flow rate that is lost to drift. The drift eliminators to be used on the proposed cooling tower will be designed such that the drift rate is less than a specified percentage of the circulating water. Typical geometries for the drift eliminators include chevron blade, honeycomb, or wave form patterns, which attempt to optimize droplet impingement with minimal pressure drop.

Table 4-1 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM_{10} releases from utility-scale cooling towers include:

- Use of Dry Cooling (no water circulation) Heat Exchanger Units
- High-Efficiency Drift Eliminators, as low as 0.0005 percent of circulating flow
- Limitations on TDS concentrations in the circulating water
- Combinations of Drift Eliminator efficiency rating and TDS limit
- Installation of Drift Eliminators (no efficiency specified)

The use of high-efficiency drift eliminating media to de-entrain aerosol droplets from the air flow exiting the wetted-media tower is commercially proven technique to reduce PM_{10} emissions. Compared to "conventional" drift eliminators, advanced drift eliminators reduce the PM_{10} emission rate by more than 90 percent.

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the

addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed cooling tower design will be based on 12 cooling water cycles (i.e., the concentration of dissolved solids in the circulating water will be, on average, 12 times that of the introduced make-up water), and a total dissolved solids (TDS) concentration of 200 ppmw in the make up water, which translates to a cooling water TDS concentration of 2,400 ppmw.

Lastly, the substitution of a dry cooling tower is a commercially available option that has been adopted by utility-scale combined cycle plants in arid climates, usually because of concerns other than air emissions. This option involves use of a very large, finned-tube water-to-air heat exchanger through which one or more large fans force a stream of ambient dry air to remove heat from the circulating water in the tube-side of the exchanger.

4.3 Infeasible Control Measures

One measure that has been adopted in arid, low precipitation climates is the use of a dry, i.e., non-evaporative cooling tower for heat rejection from combined-cycle power plants. Where it has been adopted, this measure is usually a means to reduce the water consumption of the plant, rather than as BACT for PM_{10} emissions. There is a very substantial capital cost penalty in adopting this technology, in addition to the process changes (e.g., operating pressures) necessary to condense water at the ambient dry bulb temperature, rather than at ambient wet bulb temperature.

Because of the high capital cost and process design changes involved in the use of a dry cooling tower, that option would not be cost effective and is removed from consideration.

4.4 Ranking Of Available Control Measures

Because all of the commercially available options that could form the basis for a BACT emission limit for PM_{10} from the cooling tower are also technically feasible, this section will rank these options. The technically feasible option of high-efficiency drift eliminators can be implemented at different levels of stringency. Development of increasingly effective de-entrainment structures now allows a cooling tower to be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT option. There are no significant costs or environmental factors which favor implementation of a less-stringent drift eliminator option.

In “top down” order from most to less stringent, the potentially available candidate control techniques are:

Combinations of high-efficiency drift eliminators and TDS limit

High-Efficiency drift eliminators to control drift to as low as 0.0005 percent of circulating flow

High-efficiency drift eliminators, as low as 0.001 percent of circulating flow

Limitations on TDS concentrations in the circulating water

Installation of Drift Eliminators (no efficiency specified)

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4.5 Consideration of Energy, Environmental and Cost Factors

Development of increasingly effective de-entrainment structures has resulted in equipment vendors claims that a cooling tower may be specified to achieve drift release no higher than 0.0005 percent of the circulating water rate. This is the most stringent BACT for cooling towers in current permits.

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to "conventional" specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 6-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM_{10} abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

4.6 Proposed BACT Limits and Control Option

Based on the information from the RBLC database survey, and the energy and cost factors described above, the proposed BACT option for the proposed cooling towers is use of drift eliminators achieving a maximum drift of 0.0005 percent of the circulating water.

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5 Internal Combustion Engine BACT Analysis

5.1 Process Description

A nominal 800 kW back-up generator powered by a diesel engine 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. Additionally, a pump powered by a nominal 240 hp diesel engine will be installed to provide water for fire suppression when power is from the grid is not available to run the electric firewater system. The diesel-powered engines will burn very low sulfur distillate oil. Other than plant emergency situations, the engines will each be operated no more than 1 hour per week for routine testing, maintenance, and inspection purposes; the engines will never be operated at the same time for these purposes.

The engines will emit criteria pollutants associated with diesel engines. Although the engine makes and models have not yet been specified, the engines will comply with the emission standards for emergency and stationary fire pump engines in 40 CFR Part 60 Subpart IIII (Stationary Compression Ignition Reciprocating Engine NSPS).

5.2 NO_X BACT

5.2.1 Available Control Technologies and Technical Feasibility

There are a limited number of technically-feasible NO_X control technologies that are commercially available for internal combustion engines. Two general types of control options have emerged as technically feasible: combustion process modifications, and post combustion controls. In practice, the high temperature and relatively low volumetric flow of the engine exhaust eliminates post-combustion controls from consideration. Table 5-1 summarizes recent BACT determinations for internal combustion engines.

<u>Combustion Process Modifications</u>

This option is incorporated in the engine design. Typical design features include electronic fuel/air ratio and timing controllers, pre-chamber ignition, intercoolers, and lean-burn fuel mix. Currently available new engines include these features as standard equipment; accordingly this measure is deemed the baseline case for purposes of the BACT analysis.

<u>Selective Catalytic Reduction (SCR)</u>

In this technology, nitrogen oxides are reduced to gaseous nitrogen by reaction with ammonia in the presence of a supported precious metal catalyst. The SCR system includes a catalyst module downstream of the engine exhaust. Just upstream of the catalyst, a reagent liquid (typically ammonia or urea solution) is injected directly into the exhaust stream.

<u>Non-Selective Catalytic Reduction (NSCR)</u>

Similar to automobile catalytic converters, this method employs noble metal catalysts to oxidize nitrogen oxides to molecular nitrogen. It operates in regimes with less than four percent oxygen

in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean-burn internal combustion engines.

5.2.2 Energy and Environmental Considerations

There are several distinguishing factors between the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Absent an emergency situation, the fire pump engine proposed for the KEC will only operate infrequently and for brief testing and maintenance checks (Subpart IIII limits these checks to 100 hours per year). These short, transient operating periods significantly reduce the effectiveness of the post-combustion controls.

Further, it should be assumed that ammonia emissions will occur under some or all operating conditions. This represents an additional air pollutant that is not emitted when SCR is not used for these engines. Also, the handling and storage of substantial volumes of the required ammonia or urea reagent solutions can pose an additional safety risk to facility personnel, and the risk of environmental harm in the event of an accidental release.

The SCR catalyst requires periodic cleaning due to fouling of the surfaces due to the presence of trace contaminants, such as sulfur compounds, particulate, and organic species. This requirement generates a secondary waste stream of contaminated cleaning solutions that must be disposed as hazardous waste.

When SCR or any add-on emission control technology is used, additional auxiliary equipment such as pumps and motors must be added. Also, the presence of the catalyst module adds an increment of pressure drop to the exhaust train. To avoid a substantial drop-off in engine performance, the SCR modules must be designed to minimize the increase in back pressure. However, the energy requirements of auxiliary equipment and even minor back-pressure increases reduce the net energy efficiency of the plant. In contrast, the implementation of combustion process controls does not require an add-on system with increased energy use by auxiliary equipment, or the use of catalyst and ammonia materials. There is some additional complexity in the engine controls for this option. Proper engine tuning and fuel/air ratio is needed across the full load range to achieve reduced emissions while avoiding a reduction in engine efficiency. The automatic fuel/air ratio controller helps accomplish this objective.

5.2.3 Ranking of Control Options

With regard to NO_X emission abatement, the ranking of the technically-feasible options is straightforward. The use of SCR offers the highest potential level of control for the proposed diesel-fired emergency engines. Up to 90 percent reduction in NO_X mass emission at all load levels is claimed for typical internal combustion engines.

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning

an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

5.2.4 Economic Analysis for Controls

Since advanced NO_X controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Addition of SCR is then analyzed as the next incremental control technology, in terms of both control level and cost.

The annualized operating costs for addition of SCR to either of the diesel engines would be about $79,000 per year. The estimated total capital investment is over $240,000, based on purchased equipment cost estimates. Capital recovery is the single largest annual expense, based on 7 percent prevailing interest rate, and 10-year service period. Additional maintenance charges are also encountered for operation of the systems and annual catalyst cleaning. This investment would provide about 0.081 tons of NO_X reduction per year, assuming 90 percent emission control efficiency. Cost effectiveness is more than $974,000 per ton, which represents a prohibitively high cost for this BACT option.

5.2.5 Proposed BACT

A cost effectiveness analysis for application has shown that use of SCR is cost prohibitive as a more-stringent control for the emergency engines proposed for the KEC. The proposed BACT for this engine is the combustion modifications supplied as standard equipment with the candidate types of engines which enable the manufacturer to certify the engines under Subpart IIII. Subpart IIII limits non-emergency hours of operation to 100 hours per year, but KEC would limit these operations to 52 hours per year for each engine.

5.3 CO and VOC BACT

As for NO_X, CO and VOC emissions for the emergency diesel engines selected for installation at the KEC would be certified by the manufacturer to achieve the applicable standards in Subpart IIII, and would be operated less than hours per year in a non-emergency mode as required by Subpart IIII.

5.3.1 Technically-Feasible Controls

For CO emissions, the commercially available control means for IC engines are:

Combustion Process Modifications - This option is implemented in the design of the internal combustion engine. Typical design features include an electronic fuel/air ratio control and ignition retard, turbocharging, intercoolers, and lean-burn fuel mix. Currently available engines include these features as standard equipment, so these measures are used as the base case for the BACT cost-effectiveness analysis.

Catalytic Oxidation – This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engine. In the catalyst module, CO and VOCs diffuse through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst

particles. Oxidation reactions on the catalyst surface forms carbon dioxide and water. Typical vendor indications are that 95 percent reduction in CO and 50 percent reduction in VOC emissions should be achieved.

5.3.2 Cost Effectiveness Analysis

Given the low number of routine operating hours per year, the cost for catalytic oxidation for CO and VOC control will be prohibitive. The estimated annualized cost to add catalytic oxidation to each of the proposed engines is approximately $30,300. This investment would reduce CO and VOC emissions by 0.013 and 0.0017 tons per year, respectively, assuming a 95 percent reduction in emissions and 100 hours per year of non-emergency operation. Cost effectiveness for this equipment would be more than $2,100,000 per ton of CO and VOC abated for the engines, which represents a prohibitively high cost for this BACT option.

5.3.3 Proposed BACT

Based on the cost effectiveness analysis for application of catalytic oxidation as a more-stringent increment of control, the proposed BACT for the emergency engines is the combustion modifications supplied by the manufacturer as standard equipment that enable the engines to meet the emission standards in Subpart IIII. Annual emissions would be limited by restricting non-emergency hours of operation to 52 hours per year, which is less than the 100 hours per year required by Subpart IIII.

5.3.4 SO_2 and PM BACT

The emergency engines proposed for the KEC will use ultra-low sulfur diesel (ULSD) fuel which has a sulfur content of no more than 0.0015 percent (15 ppm) by weight. Given the low emission rates expected as a result of using ULSD fuel, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost effective emission control. Use of engines certified by manufacturers to meet Subpart IIII emission standards, use of ULSD fuel, and limitation of non-emergency operation to less than 100 hours per year (as required by Subpart IIII) will provide low emissions of SO_2 and PM_{10}, and are proposed as BACT measures for these pollutants.

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Tables

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Table 2-1 Recent BACT Determinations for Natural Gas-Fired Combined-Cycle Combustion Turbines

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
SJ 08-01	05-27-11	Avenal Power Center, LLC	Kings County, CA	Combined Cycle Gas Turbine with Duct Burner	180 MW and 562 MMBtu/hr of duct firing	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15% O_2 PM_{10} – 11.78 lb/hr	SCR, LNB, Oxidation Catalyst, Clean Fuel	BACT-PSD
OR-0048	12-29-10	Portland General Electric	Morrow County, OR	Combined Cycle Gas Turbine	2,866 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 PM_{10} – 2.5 lb/MMcf	SCR, Clean Fuel	BACT-PSD
AK-0071	12-20-10	Chugach Electric Association, Inc.	Municipality of Anchorage, AK	Combined Cycle Gas Turbine	46 MW	NO_X – 5 ppmvd PM_{10} – 0.0066 lb/MMBtu	SCR, GCPs	BACT-PSD
ID-0018	06-25-10	Idaho Power Company	Payette County, ID	Combined Cycle Gas Turbine with Duct Burner	2,375 MMBtu/hr	NO_X – 2 ppmvd CO – 2 ppmvd VOC – 2 ppmvd	SCR, LNB, Oxidation Catalyst, GCPs	BACT-PSD
GA-0138	04-08-10	Live Oaks Company, LLD	Glynn County, GA	Combined Cycle Gas Turbine	600 MW	NO_X – 2.5 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15% O_2 VOC – 2 ppmvd @ 15% O_2	SCR, LNB, Oxidation Catalyst, GCPs	BACT-PSD
SE 07-02	03-11-10	Victorville 2 Hybrid Power Project	San Bernardino County, CA	Combined Cycle Gas Turbine with Duct Burner	154 MW and 424 MMBtu/hr of ductfiring	NO_X – 2 ppmvd @ 15% O_2 CO – 3 ppmvd @ 15% O_2 PM_{10} – 2 gr/100 scf gas	SCR, Oxidation Catalyst, Clean Fuel	BACT-PSD
15487	02-03-10	Russell City Energy Co., LLC	Alameda County, CA	Combined Cycle Gas Turbine with Duct Burner	2,039 MMBtu/hr and 200 MMBtu/hr of duct firing	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15% O_2 PM_{10} – 0.0036 lb/MMBtu	SCR, Oxidation Catalyst, Clean Fuel	BACT, PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
08-AFC-10	01-22-10	Lodi Energy Center	San Joaquin County, CA	Combined Cycle Gas Turbine with Duct Burner	1,886 MMBtu/hr and 222 MMBtu/hr duct firing	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15% O_2 VOC – 1.4 ppmvd @ 15% O_2	SCR, Oxidation Catalyst	BACT-PSD
TX-0548	08-18-09	Madison Bell Partners, LP	Madison County, TX	Combined Cycle Gas Turbine with Duct Burner	275 MW	NO_X – 2 ppmvd @ 15% O_2 CO – 17.5 ppmvd @ 15% O_2 VOC – 2.5 ppmvd @ 15% O_2	SCR, GCPs	BACT-PSD
TX-0547	06-22-09	Lamar Power Partners II, LLC	Lamar County, TX	Combined Cycle Gas Turbine with Duct Burner	250 MW	NO_X – 2 ppmvd @ 15% O_2 CO – 15 ppmvd @ 15% O_2 VOC – 4 ppmvd @ 15% O_2	SCR, GCPs	BACT-PSD
TX-0546	06-17-09	Pattillo Branch Power Co., LLC	Fannin County, TX	Combined Cycle Gas Turbine with Duct Burner	350 MW	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15% O_2 VOC – 2 ppmvd @ 15% O_2	SCR, Oxidation Catalyst	BACT-PSD
FL-0304	09-08-08	Florid Municipal Power Agency (FMPA)	Osceola County, FL	Combined Cycle Gas Turbine with Duct Burner	1,860 MMBtu/hr	NO_X – 2 ppmvd CO – 6 ppmvd $PM_{10/}SO_2$ – 2 gr/100 scf gas	SCR, GCPs, Low Sulfur Fuel	BACT-PSD
FL-0303	07-30-08	Florida Power & Light Co.	Palm Beach County, FL	Combined Cycle Gas Turbine with Duct Burner	2,333 MMBtu/hr	NO_X – 2 ppmvd CO – 6 ppmvd $PM_{10/}SO_2$ – 2 gr/100 scf gas VOC – 1.2 ppmvd 10% Opacity	LNBs, SCR, GCPs, Low Sulfur Fuel	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
LA-0224	03-20-08	Southwest Electric Power Company (SWEPCO)	Caddo Parish, LA	Combined Cycle Gas Turbine	2,110 MMBtu/hr	NO_X – 4 ppmvd@15% O_2 CO – 10 ppmvd @ 15%O_2 VOC – 4.9 ppmvd @ 15%O_2 PM_{10} – 0.011 lb/MMBtu SO_2 – 0.0057 lb/MMBtu	LNBs, SCR, GCPs, Low Sulfur Fuel	BACT-PSD
CT-0151	02-25-08	Kleen Energy Systems, LLC	Middlesex County, CT	Combustion Turbine with Duct Burner	2.1 MMcf/hr	NO_X – 2 ppm @ 15% O_2 CO – 0.9 ppmvd @ 15%O_2 VOC – 5 ppmvd @ 15%O_2 PM_{10} – 0.006 lb/MMBtu SO_2 – 0.0020 lb/MMBtu	LNBs, SCR, Oxidation Catalyst	LAER (NO_X); BACT-PSD
OK-0129	1-23-09	Associated Electric Cooperative, Inc.	Mayes County, OK	Combined Cycle Gas Turbine	1,882 MMBTU/H	NO_X – 2 ppm @ 15% O_2 CO – 8 ppmvd @ 15%O_2 VOC – 0.3 ppmvd @ 15%O_2 PM_{10} – 0.0035 lb/MMBtu SO_2 – 1.06 lb/hr	SCR, LNBs, GCPs, Low Sulfur Fuel	BACT-PSD (NO_X, CO, VOC)
VA-0308	01-14-08	Virginia Electric and Power Co.	Warren County, VA	Combined Cycle Gas Turbine with Duct Burner	1,717-2,204 MMBtu/hr	NO_X – 2 ppmvd CO – 1.2 ppmvd VOC – 0.7 ppmvd PM_{10} – 0.013 lb/MMBtu SO_2 – 0.002 lb/MMBtu	LNBs, SCR, GCPs, Oxidation Catalyst	BACT-PSD
GA-0127	01-07-08	Southern Company/ Georgia Power	Cobb County, GA	Combined Cycle Combustion Turbine	254 MW	NO_X – 6 ppmvd @ 15% O_2 CO – 1.8 ppmvd @ 15%O_2 VOC – 1.8 ppmvd @ 15%O_2 PM_{10} – 0.1 lb/MMBtu 20% Opacity	LNBs, SCR, Water Injection, Oxidation Catalyst	LAER (VOC); PSD-BACT
MN-0071	06-05-07	Minnesota Municipal Power Agency	Rice County, MN	Combined Cycle Combustion Turbine with Duct Burner	1,758 MMBtu/hr	NO_X – 3 ppmvd CO – 9 ppmvd VOC – 3 ppmvd PM_{10} – 0.01 lb/MMBtu	LNBs, SCR, Water Injection, GCPs	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
CA-1144	04-25-07	Caithness Blythe II, LLC	Riverside County, CA	Combined Cycle Combustion Turbine	170 MW	NO_X – 2 ppmvd @ 15% O_2 CO – 4 ppmvd @ 15%O_2	SCR	BACT-PSD
FL-0285	01-26-07	Progress Energy Florida (PEF)	Pinellas County, FL	Combined Cycle Combustion Turbine	1,972 MMBtu/hr	NO_X – 15 ppmvd CO – 8 ppmvd VOC – 1.5 ppmvd @ 15%O_2 10% Opacity	Water Injection, GCPs	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	West Palm Beach County, FL	Combined Cycle Combustion Gas Turbine	2,333 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 CO – 8 ppmvd @ 15%O_2 VOC – 1.5 ppmvd @ 15%O_2	LNBs, SCR, Water Injection	BACT-PSD
OK-0115	12-12-06	Energetix	Comanche County, OK	Combustion Turbine And Duct Burner	1,911 MMBtu/hr	NO_X – 3.5 ppmvd @ 15% O_2 CO – 16.4 ppmvd @ 15%O_2 PM_{10} – 0.0067 lb/MMBtu	LNBs, SCR, GCPs	BACT-PSD
NY-0095	05-10-06	Caithness Bellport, LLC	Suffolk County, NY	Combined Cycle Combustion Turbine	2,221 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15%O_2 PM_{10} – 0.0067 lb/MMBtu SO_2 – 0.0011 lb/MMBtu	SCR, Oxidation Catalyst, Low Sulfur Fuel	BACT-PSD
CO-0056	05-02-06	Calpine Corp.	Weld County, CO	Combined Cycle Turbine	300 MW	NO_X – 3 ppm @ 15% O_2 CO – 3 ppm @ 15%O_2 VOC – 0.0029 lb/MMBtu PM_{10} – 0.0074 lb/MMBtu 10% Opacity	LNBs, SCR, GCPs, Oxidation Catalyst, Low Sulfur Fuel	BACT-PSD

Table 3-1 Recent BACT Determinations for Natural Gas-Fired Auxiliary Boilers

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
SJ 08-01	05-27-11	Avenal Power Center, LLC	Kings County, CA	Auxiliary Boiler	37.4 MMBtu/hr	NO_X – 9 ppmvd @ 3% O_2 CO – 50 ppmvd @ 3% O_2 PM_{10} – 0.034 gr/dscf	ULNB, Low Sulfur Fuel	BACT-PSD
OR-0048	12-29-10	Portland General Electric	Morrow County, OR	Auxiliary Boiler	91 MMBtu/hr	NO_X – 4.5 lb/hr PM_{10} – 2.5 lb/MMcf	LNBs, Low Sulfur Fuel	BACT-PSD
SE 07-02	03-11-10	Victorville 2 Hybrid Power Project	San Bernardino County, CA	Auxiliary Boiler	35 MMBtu/hr	NO_X – 9 ppmvd @ 3% O_2 CO – 50 ppmvd @ 3% O_2 PM_{10} – 0.2 gr/100dscf	ULNB, Restricted Operating Hours (500 hr/yr)	BACT-PSD
08-AFC-10	01-22-10	Lodi Energy Center	San Joaquin County, CA	Auxiliary Boiler	36.5 MMBtu/hr	NO_X – 7 ppmvd @ 3% O_2 CO – 50 ppmvd @ 3% O_2 VOC – 10 ppmvd @ 3% O_2 PM_{10} – 0.0076 lb/MMBtu SO_2 – 0.00285 lb/MMBtu	LNBs	BACT-PSD
OK-0129	1-23-09	Associated Electric Cooperative, Inc.	Mayes County, OK	Auxiliary Boiler	33.5 MMBtu/hr	NO_X – 0.07 lb/MMBtu CO – 5.02 lb/hr VOC – 0.54 lb/hr SO_2 – 0.03 lb/hr	LNBs, GCPs, Low Sulfur Fuel	BACT-PSD (NO_X and VOC)
NH-0015	04-18-08	Concord Steam Corp.	Merrimack County, NH	Auxiliary Boiler	76.8 MMBtu/hr	NO_X – 0.049 lb/MMBtu	LNBs, FGR, Restricted Hours of Operation (700)	LAER

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
GA-0127	01-07-08	Southern Company/ Georgia Power	Cobb County, GA	Auxiliary Boiler	200 MMBtu/hr	CO – 0.073 lb/MMBtu VOC – 0.0051 lb/MMBtu	None	BACT-PSD (CO) LAER (VOC)
FL-0285	01-26-07	Progress Energy Florida (PEF)	Pinnellas County, FL	Auxiliary Boiler	99 MMBtu/hr	CO – 0.08 lb/MMBtu Opacity 10%	Low Sulfur Fuel	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	West Palm Beach County, FL	Auxiliary Boiler	99.8 MMBtu/hr	NO_X – 0.05 lb/MMBtu CO – 0.08 lb/MMBtu PM_{10}/SO_2 – 2 gr/100 scf Opacity 10%	Low Sulfur Fuel	BACT-PSD

Table 4-1 Recent BACT Determinations for Cooling Towers

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
ID-0018	06-25-10	Idaho Power Company	Payette, ID	Cooling Tower	63,200 gal/min	None	Drift Eliminators	BACT-PSD
SE 07-02	03-11-10	Victorville 2 Hybrid Power Project	San Bernardino County, CA	Cooling Tower	130,000 gal/min	PM_{10} – 0.0005% of cooling water; TDS not to exceed 5,000 ppm	Drift Eliminators, TDS Limit	BACT-PSD
15487	02-03-10	Russell City Energy Co., LLC	Alameda County, CA	Cooling Tower	141,352 gal/min	PM_{10} – 0.0005% of cooling water; TDS not to exceed 6,200 ppm	Mist Eliminators; TDS Limit	BACT-PSD
08-AFC-10	01-22-10	Lodi Energy Center	San Joaquin County, CA	Cooling Tower	69,000 gal/min	PM_{10} – 0.0005% of cooling water	Drift Eliminators	BACT-PSD
OK-0129	01-23-09	Associated Electric Cooperative Inc	Mayes, OK	Cooling Tower	Not Provided	PM_{10} – 3.6 lb/hr	Drift Eliminators	BACT-PSD
FL-0304	09-08-08	Florida Municipal Power Agency (FMPA)	Osceola County, FL	Cooling Tower	Not Provided	PM_{10} – 0.0005% of cooling water	Mist Eliminators	BACT-PSD
FL-0303	07-30-08	Florida Power And Light Company (FP&L)	Palm Beach County, FL	Cooling Tower	Not Provided	PM/PM_{10} – 0.0005% of cooling water	Mist Eliminators	BACT-PSD
LA-0136	07-23-08	The Dow Chemical Company	Iberville, LA	Cooling Tower	Not Provided	PM_{10} – 0.005% of cooling water	Drift Eliminators	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
LA-0148	05-28-08	Red River Environmental Products, LLC	Red River Parish, LA	Cooling Towers	10,750 gal/min	PM – 0.41 lb/hr	Drift Elimination System	BACT-PSD
LA-0224	03-20-08	Southwest Electric Power Company	Caddo Parish, LA	Cooling Tower	140,000 gal/min	PM – 1.4 lb/hr	Mist Eliminators	BACT-PSD
LA-0221	11-30-07	Entergy Louisiana, LLC	St. Charles Parish, LA	Cooling Tower	5,000 gal/min	PM – 0.5 lb/hr	Drift Eliminator with 99.999% Control Eff.	BACT-PSD
ND-0024	09-14-07	Great River Energy	Stutsman County, ND	Cooling Tower	80,000 gal/min	PM – 0.0005% of cooling water	Drift Eliminator	BACT-PSD
MN-0070	09-07-07	Minnesota Steel Industries, LLC	Itasca County, MN	Cooling Tower	Not Provided	PM, PM_{10} – 0.005% drift rate	Design to minimize drift	BACT-PSD
IA-0089	08-08-07	Homeland Energy Solutions, LLC	Chickasaw County, IA	Cooling Tower	5,000 gal/min	PM, PM_{10} – 0.0005% drift	Drift Eliminator/ Demister	BACT-PSD
IA-0088	06-29-07	Archer Daniels Midland	Linn County, IA	Cooling Tower	150,000 gal/min	PM, PM_{10} – 0.0005% drift	Drift Eliminator	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	Palm Beach, FL	Two 26- Cell Mechanical Draft Cooling Tower	306,000 Gal/Min	PM_{10} – 0.0005% of cooling water	Drift Eliminator	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
LA-0211	12-27-06	Marathon Petroleum Co., LLC	St. John the Baptist Parish, LA	Cooling Towers	30,000 & 96,250 gal/min	PM_{10} – 0.005% drift	High Efficiency Drift Eliminators	BACT-PSD
FL-0294	12-22-06	Progress Energy Florida	Pasco County, FL	Cooling Towers	660,000 gal/min	PM – 108 tons/year	Drift Eliminators	BACT-PSD
WV-0024	04-26-06	Western Greenbrier Co-Generation, LLC	Greenbrier County, WV	Cooling Tower	55,000 gal/min	PM – 0.79 lb/hr	Drift Eliminators with 0.0005% drift	BACT-PSD
IA-0082	04-19-06	Golden Grain Energy	Cerro Gordo County, IA	Cooling Tower	NA	PM_{10} – 1.33 lb/hr	Mist Eliminators	BACT-PSD
LA-0202	02-23-06	Cleco Power, LLC	Rapides Parish, LA	Cooling Tower	301,874 gal/min	PM_{10} – 1.13 lb/hr 3.31 tons/year	Drift Eliminators	BACT-PSD

Table 5-1 Recent BACT Determinations For Emergency Internal Combustion Engines

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
SJ 08-01	05-27-11	Avenal Power Center, LLC	Kings County, CA	Emergency Generator; Emergency Fire Pump	550 kW; 288 hp	NO_X – 1.0 & 3.4 g/hp-hr CO – 0.21 & 0.447 g/hp-hr PM_{10} – 0.34 g/hp-hr	SCR, Oxidation Catalyst; None	BACT-PSD
AK-0071	12-20-10	Chugach Electric Association, Inc.	Muncipality of Anchorage, AK	Caterpillar 3215C Black Start Generator	1,500 kWe	NO_X – 6.4 g/kW-hr PM_{10} – 0.03 g/Kw-hr	GCPs	BACT-PSD
ID-0018	06-25-10	Idaho Power Company	Payette County, ID	Emergency Generator Engine; Fire Pump Engine	750 kW; 235 kW	NO_X + NMHC – 6.4 & 4 g/kW-hr CO – 3.5 g/kW-hr PM_{10} – 0.2 g/kW-hr	Tier 2 Engine, GCPs; Tier 3 Engine, GCPs	BACT-PSD
SE 07-02	03-11-10	Victorville 2 Hybrid Power Project	San Bernardino County, CA	Emergency Generator Engine; Fire Pump Engine	2,000 kW; 135 kW	NO_X – 6.0 & 3.8 g/kW-hr CO – 3.5 g/kW-hr $PM_{2.5}$ – 0.20 g/kW-hr	Low-Sulfur Fuel	BACT-PSD
15487	02-03-10	Russell City Energy Co., LLC	Alameda County, CA	Fire Pump	300 hp	None	None	BACT-PSD
08-AFC-10	01-22-10	Lodi Energy Center	San Joaquin County, CA	Emergency Fire Pump	240 bhp	None	None	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
OK-0129	01-23-09	Associated Electric Cooperative Inc	Mayes County, OK	Emergency Diesel Generator; Emergency Fire Pump	2,200 hp; 267 hp	NO_X + NMHC – 6.4 & 7.8 g/kW-hr CO – 3.5 & 2.6 g/kW-hr PM_{10} – 0.2 & 0.4 g/kW-hr VOC – 1.55 & 0.66 lb/hr SO_2 – 0.89 & 0.11 lb/hr	GCPs, Low-Sulfur Diesel	BACT-PSD
FL-0304	09-08-08	Florida Municipal Power Agency (FMPA)	Osceola County, FL	Emergency Fire Pump	> 300 hp	NO_X – 3 g/bhp-hr CO – 2.6 g/bhp-hr PM – 0.15 g/bhp-hr	Not provided	BACT-PSD
FL-0303	07-30-08	Florida Power And Light Company (FP&L)	Palm Beach County, FL	Two Nominal 2,250 Kw (~ 21 Mmbtu/H) Emergency Generators	2,250 kW	NO_X – 6.9 g/bhp-hr CO – 8 g/bhp-hr PM_{10} – 0.4 g/bhp-hr HC – 1 g/bhp-hr SO_2 – 0.0015% S in fuel	Low-Sulfur Fuel	BACT-PSD
LA-0224	03-20-08	Southwest Electric Power Co.	Caddo Parish, LA	Diesel Fire Pump	310 hp	NO_x – 9.61 lb/hr CO – 2.07 lb/hr PM_{10} – 0.68 lb/hr SO_2 – 0.64 lb/hr VOC – 0.77 lb/hr	Low-Sulfur fuel, limited operation hours, and proper engine maintenance	BACT-PSD
MN-0070	09-07-07	Minnesota Steel Industries, LLC	Itasca County, MN	Diesel Fire Water Pumps	Not Provided	SO_2 – 0.05% in fuel VE – 5%	Limited Sulfur in fuel, limited hours	BACT-PSD

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0071	06-05-07	Minnesota Municipal Power Agency	Rice County, MN	Emergency Generator	1,750 kW	NO_X – 0.024 lb/hp-hr CO – 0.0055 lb/hp-hr PM – 0.0007 lb/hp-hr PM_{10} – 0.0004 lb/hp-hr VOC – 0.0007 lb/hp-hr SO_2 – 0.0004 lb/hp-hr	Operating limit of 10 hours per day	BACT-PSD
CA-1144	04-25-07	Caithness Blythe II, LLC	Riverside County, CA	Fire Pump	303 hp	NO_x – 7.5 lb/hr CO – 0.7 lb/hr PM_{10} – 0.1 lb/hr	Fuel with less than 0.05% sulfur by weight	BACT-PSD
FL-0285	01-26-07	Progress Energy Florida (Pef)	Pinellas, FL	Emergency Diesel Fire Pump	300 hp	NO_X + NMHC – 7.8 g/bhp-hr CO – 2.6 g/bhp-hr	None	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	Palm Beach, FL	Emergency Generators; Emergency Fire Pump	2,250 kW; <300 hp	NO_X – 6.9 & 7.8 (w/NMOC) g/bhp-hr CO – 8.5 & 2.6 g/bhp-hr PM_{10} – 0.4 g/bhp-hr HC – 1 g/bhp-hr SO_2 – 0.0015% S in fuel	None	BACT-PSD
IA-0084	11-30-06	ADM Corn Processing	Clinton County, IA	Fire Pump Engine	500 hp	VOC – 3 g/HP-hr	GCP	BACT-PSD

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Appendix C:
Best Available Control
Technology Analysis
for Greenhouse Gases

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Combined-Cycle Combustion Turbine Project Greenhouse Gas Best Available Control Technology Analysis

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1 Introduction

Energy Northwest proposes to construct and operate the Kalama Energy Center electrical power generating facility. Natural gas would be used to run a combined-cycle combustion turbine generating plant to provide electricity for intermediate-loads and renewable-shaping services. The Kalama Energy Center's maximum net output would not equal or exceed 350 MWe.

On May 13, 2010, USEPA issued the final "Tailoring Rule" with the stated intent of establishing a "common sense approach" to addressing greenhouse gas 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. The first step of the Tailoring Rule, which began on January 2, 2011, and lasts until June 30, 2011, requires sources already subject to the PSD permitting programs to meet that program's permitting requirements for greenhouse gases. 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, are subject to PSD review for GHGs.

The second step of the rule, which starts on July 1, 2011, and lasts until June 30, 2013, casts a wider net than the first. New construction projects expected to emit at least 100,000 tpy of total greenhouse gases on a CO_2e basis, or modifications at existing facilities that are expected to increase total greenhouse gas emissions by at least 75,000 tpy CO_2e, will be subject to PSD permitting requirements, even if they do not significantly increase emissions of any other PSD pollutant. Because the proposed facility is expected to emit GHGs at a rate greater than 75,000 tpy CO_2e, the 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 electric power generating facility would be comprised of the following major pieces of equipment:

- One Power Generation Unit (PGU), 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 Six-Cell Cooling Tower,
- One Auxiliary Boiler,
- One Diesel-Powered Back-Up Generator
- One Diesel-Powered Emergency Fire Pump, and
- Three High-Voltage Circuit Breakers.

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Of these, only 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. Although there is a wide range of controls and associated costs that could be considered for criteria air pollutants, permit-issuing agencies have an understanding of which emission control options are appropriate and cost effective. In contrast, BACT analyses, BACT determinations, and cost-effectiveness criteria for GHGs are relatively new with minimal, if any, guidance.

In November 2010, USEPA issued guidance for conducting BACT analyses for GHGs and updated the guidance in March 2011 (hereafter referred to as “the March 2011 Guidance”). USEPA recommended (but did not require) that permitting agencies apply to GHGs the same “top down” process applied to determine criteria pollutant BACT. In this process, potentially available control technologies are identified and evaluated for application to the proposed project. Feasible options are ranked in descending order of control effectiveness. The most stringent alternative is examined and is established as BACT unless the applicant demonstrates and the permitting authority agrees that energy, environmental or economic impacts justify a conclusion that the most stringent technology is not achievable. In that case the next stringent alternative is considered. 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.

Each step is discussed further in the sections that follow.

1.2.1 Step 1 – Identify Available Control Technologies

The first step in the top-down procedure is to identify all available control technologies and emission reduction options for each subject pollutant. Available control technologies are those with a practical potential for application to the emission unit. For criteria pollutants, applicants typically identify appropriate control technologies by reviewing the following sources of information:

- USEPA RACT/BACT/LAER Clearinghouse (RBLC)
- USEPA Control Technology Center (CTC)
- Recent Permit Actions by other State and Local Agencies, and
- Vendor Information

Because BACT for GHGs is a new requirement, there are very few BACT precedents. In preparing this BACT analysis, ENVIRON reviewed BACT analyses for a combined cycle power plant in the San Francisco Bay area (Russell City), a proposed combination refinery and integrated gasification combined cycle (IGCC) facility in South Dakota (Hyperion Energy Center), and a biomass-fired cogeneration facility adjacent to a paper mill in Wisconsin (We Energies/Domtar Biomass Energy Project).

Consistent with these precedents and EPA's March 2011 Guidance, this analysis demonstrates that the design of the proposed facility will achieve a very high degree of energy efficiency. In BACT parlance, this is considered "lower-polluting processes/practices" as opposed to post-

combustion or "end-of-stack" controls. Given the limited technological options available for end-of-stack GHG emission controls, EPA's initial BACT guidance emphasizes energy efficiency. In addition to reducing GHG emissions, energy efficiency also minimizes criteria and toxic air pollutant emissions.

A control technology must be "available" to be considered BACT. According to EPA's draft 1990 NSR manual "'[a]vailable' means that the method's systems and techniques are commercially available." BACT also does not require the applicant to participate in a research and development project to determine if a technology is "available" for a particular use.

Theoretical, experimental or developing technologies are not "available" under BACT. Technologies with questionable or dubious reliability are likewise not considered "available" under BACT, and the applicant is not required to use them. BACT does not require an applicant to speculate as to whether an undemonstrated technology will effectively control the pollutant in question from the proposed source. Applicants are not required to accept the risk that a theoretically feasible, but unproven, technology will effectively and economically reduce emissions from the proposed source.

In addition, the EPA has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. Considerable argument and litigation has been generated over what constitutes "redefinition of the source." The most recent approach outlined by the Environmental Appeals Board (EAB) is contained in a 2009 ruling to remand a permit issued to Desert Rock Energy Co., LLC. In that ruling, which referred extensively to a previous EAB ruling (Prairie State Generation Co., LLC), the EAB says that the reviewing agency should seek to answer the question: "when does the imposition of control technology require enough of a redesign of the proposed facility that it strays over the dividing line to become an impermissible redefinition of the source?"

In response to its own question, the EAB stated that "the permit applicant initially defines the proposed facility's end, object, aim, or purpose – that is the facility's basic design, although the applicant's definition must be for reasons independent of air permitting." Furthermore, the permit issuer should "take a 'hard look' at the application determination in order to discern which design elements are inherent for the applicant's purpose and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility, while keeping in mind that BACT, in most cases, should not be applied to regulate the applicant's purpose or objective for the proposed facility."

1.2.2 Step 2 – Eliminate Technically Infeasible Control Technologies

The second step in performing the top-down BACT analysis is to eliminate all technically infeasible options. The determination that a control technology is technically infeasible is source-specific and based upon physical, chemical, and engineering principles. Technical feasibility is addressed in EPA's March 2011 Guidance:

> *EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of*

> *source under review, or (2) is available and applicable to the source type under review. If a technology has been operated on the same type of source, it is presumed to be technically feasible. An available technology from Step 1, however, cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been operated successfully on the type of source under review, then questions regarding "availability" and "applicability" to the particular source type under review should be considered in order for the technology to be eliminated as technically infeasible.*

Prior guidance and judicial decisions confirm that "feasible technology" means design or equipment that has progressed beyond the conceptual and pilot testing phases, is commercially available, and has been demonstrated on a full-scale emission unit of the type of that is the subject of the BACT analysis, for a period of time sufficient to indicate reliable operation. These criteria are especially important for GHG BACT analyses due to the unproven nature of many GHG control schemes.

"Demonstrated in practice" is another important concept that addresses the question of whether a technology should be considered available. In its New Source Review Improvement Rule (issued November 22, 2002), EPA included a definition of "demonstrated in practice." This definition prescribes which technologies must be considered in BACT and LAER determinations by defining the information that must be reviewed to identify candidate technologies, the amount of time the technology must be in use, and its performance during that time. A technology installed and operating on an emissions unit (or units) must meet the following criteria to be considered "demonstrated in practice:"

- Has operated at a minimum of 50 percent of design capacity for at least 6 months; and
- The pollution control efficiency performance has been verified by either:

  1) a performance test, or

  2) performance data collected at the maximum design capacity of the emissions unit (or units) being controlled, or 90 percent or more of the control technology's designed specifications.

Although this definition of "demonstrated in practice" does not have any regulatory standing in the analysis presented in this report, it does provide some useful guidance for evaluating whether certain technologies are "available," and therefore worthy of consideration as BACT.

1.2.3 Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the top-down BACT analysis is to rank all remaining control technologies with respect to control effectiveness (i.e., by emission limit or removal efficiency, as applicable). The emission limit or removal efficiency used in the ranking process is that which the technology has demonstrated can be achieved consistently under reasonably foreseeable worst-case conditions with an adequate margin of safety. A limit or removal efficiency that can be achieved only occasionally under best-case circumstances is not to be considered.

For GHGs, control options are ranked based on total CO_2e rather than the total mass or mass of individual GHGs.

1.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

In this step, an analysis is performed on each remaining control technology to determine whether the energy, economic, or environmental impacts from a given technology outweigh their benefits. Factors such as control efficiency, anticipated emission rate, expected emissions reduction, and economic, environmental, and energy impacts, are to be considered.

If the top-ranked technology is chosen, and there are no significant or unusual environmental impacts associated with that technology that have the potential to affect its selection, the BACT analysis is complete, and no further analysis is required. However, if the chosen technology is not the top-ranked option, the economic, environmental, and energy impacts of the chosen technology, and each more-effective technology, must be evaluated and compared to justify application of the selected technology. In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where the options are considered and either eliminated or adopted in order of effectiveness, the economic, energy, and environmental impacts of all options should be considered.

In performing economic analyses, USEPA's Air Pollution Control Cost Manual, published in January 2002 (EPA/452/B-02-001) provides capital and annual operating cost factors that can be used in determining the installation and operating costs of each control technology. Actual vendor installation and operation costs were used where applicable.

Cost-effectiveness evaluations for greenhouse gases are to be conducted based on reductions in CO_2e. However, as acknowledged by EPA in its March 2011 Guidance, no cost effectiveness criteria have been established for GHGs. Furthermore, there are no means by which to evaluate the environmental impacts of GHG emissions at the stationary source level. Consequently, comparisons of environmental impacts associated with GHG emissions with those of collateral criteria pollutant emissions are not possible.

1.2.5 Step 5 – Select BACT

The final step is selection of the most stringent and technically feasible emission limit and corresponding technology that was not eliminated based upon adverse economic, environmental, and energy impacts. EPA's March 2011 Guidance notes that a GHG permit may limit CO_2e based on a mass emission rate (lb/hr) or other metrics. EPA also notes that "since the environmental concern with greenhouse gases is with their cumulative impact in the environment, metrics should focus on longer-term averages (e.g., 30- or 365-day rolling average) rather than short-term averages (e.g., 3- or 24-hr rolling average)."

Although this process might appear to be tightly prescribed, 20 years of experience with the top-down BACT analysis process has resulted in a number of agency and judicial decisions that have served to guide subsequent BACT determinations:

- BACT determinations are made "on a case-by-case basis," taking into account site-specific and source-specific characteristics. These characteristics may include, among other

things, the type of fuel or raw materials that will be used, and the type and size of the emissions unit. A high degree of technical judgment must be exercised in any BACT analysis as there are various sizes and ages of the emissions units covered by an analysis.

- BACT must be achievable. The Environmental Appeals Board (EAB) has recently stated that, while BACT is forward-looking, "the word 'achievable'…constrains the permit issuer's discretion by prohibiting BACT limits that would require pollution reductions greater than what can be achieved with available methods." The EAB concluded that "the permit issuer may take into account the absence of long-term data, or the unproven long-term effectiveness of the technology, in setting the emissions limitation that is BACT for the facility." The EAB further stated that the BACT analysis "must be solidly grounded on what is presently known about the selected technology's effectiveness," and that "emissions limitations achieved by other facilities, and corresponding control technologies used at other facilities are an important source of information in determining" BACT.

EPA's March 2011 Guidance affirms that vendor confidence in emission control efficiency should be considered: "[t]he willingness of vendors to provide guarantees and the limits of these guarantees can be an important factor in determining the level of performance specified in a PSD permit"

Finally, the chosen BACT emission limit must not be less stringent than any applicable federal NSPS, NESHAP, or state-specific emission standard. It should be noted, however, that there are no federal NSPS or NESHAP GHG emission standards that apply to any of the proposed emission units. Washington has an Emission Performance Standard for baseload electric generation facilities (RCW 80.80), which will be addressed.

1.3 Cost-Effectiveness Analysis

In Step 4 of the top-down BACT analysis process, cost effectiveness is used to assess the economic impact of emission reduction alternatives. The cost effectiveness of a control option is defined as dollars per ton ($/ton) of pollutant removed or avoided when compared with some baseline (usually the uncontrolled emission rate), and is calculated as follows:

$$\frac{\text{Total Annualized Costs of Control Option}}{(\text{Baseline Annual Emissions} - \text{Control Option Annual Emissions})}$$

In cases where more than one control option is being considered, incremental cost effectiveness is often calculated, as follows, to determine the cost per ton of the additional quantity of pollutant reduced at some additional expense:

$$\frac{(\text{Total Annualized Costs of Control Option} - \text{Total Annualized Costs of Next Control Option})}{(\text{Control Option Annual Emissions} - \text{Next Control Option Annual Emissions})}$$

Step 4 of the BACT process addresses economic, energy, and environmental impacts associated with feasible control options. The economic evaluation provides an applicant an opportunity to demonstrate that the costs of pollutant removal for a particular control option are disproportionately high. However, EPA's March 2011 Guidance acknowledges "there is not a

wealth of GHG cost effectiveness data from prior permitting actions for a permitting authority to review and rely upon when determining what cost level is considered acceptable for GHG BACT." EPA also acknowledges that cost effectiveness criteria historically applied to criteria pollutant emissions are not appropriate for greenhouse gases because greenhouse gas emissions tend to be orders of magnitude greater than criteria pollutant emissions. In fact, we find that at this early stage of greenhouse gas BACT review, there is virtually no information that enables applicants or reviewing agencies to determine whether a control option is cost effective.

An Interim Report issued in February 2010 by the Climate Change Work Group of the Permits, New Source Review and Toxics Subcommittee to the EPA's Clean Air Act Advisory Committee, which includes industry, environmental, and regulatory groups, provided no consensus on greenhouse gas cost effectiveness, with values ranging from $3 per ton to $150 per ton. Some members supported not setting fixed cost effectiveness thresholds, and recommended that EPA provide guidance to permitting authorities on the range of cost effectiveness values based on the status of various control technologies.

An obvious source of carbon cost information is the value of carbon allowances or offsets. Analogous to EPA's acid rain program, an allowance is an authorization under a regulatory program to emit a certain quantity of carbon. However, a carbon offset is an emission reduction established outside of a regulatory program, and may or may not be recognized by a regulatory program.

The Regional Greenhouse Gas Initiative (RGGI, http://www.rggi.org) is the first mandatory, market-based effort in the United States to reduce greenhouse gas emissions. Ten Northeastern and Mid-Atlantic states have implemented a CO_2 cap, effective until 2014, after which the cap will be reduced by 2.5 percent each year until a total reduction of 10 percent is achieved by 2018. States sell nearly all emission allowances through auctions and invest the proceeds in consumer benefits such as energy efficiency, renewable energy, and other clean energy technologies.

At a RGGI auction held June 8, 2011, allowances averaged $1.89 per ton of CO_2. "Future" allowances also averaged $1.89 per ton, implying that the value of CO_2 allowances is not expected to change significantly in the near future. Of the over 42 million allowances offered, only 12.5 million were sold, and 91 percent of the allowances sold were purchased by electric utilities and their affiliates.

RGGI-participating states currently allow regulated power plants to use a carefully-chosen group of qualifying offsets to meet up to 3.3 percent of their CO_2 compliance obligation. Examples of offset-eligible project categories include those that capture or destroy methane from landfills or through agricultural manure management operations.

Similar in nature to RGGI allowances, European Union Allowance units (EUAs) are sold in Europe as a mechanism for achieving an EU objective of a 20 percent reduction in carbon emissions by 2020 (compared to 1990 levels). The price of an EUA in April 2011 was approximately 16 euros per metric tonne (equivalent to about $21 per short ton).

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The Chicago Climate Exchange (CCX) was a voluntary, legally binding, GHG reduction and trading system until it closed in November 2010. At that time, the price of carbon credits (which had not traded on the CCX since February 2010) ranged between $0.05 and $0.10 per metric tonne of CO_2e.

When developing the GHG Tailoring Rule, EPA used scaling to derive a Significant Emission Rate for greenhouse gases from the Significant Emission Rates for criteria pollutants. Applying a similar rationale, one could derive a greenhouse gas cost effectiveness criterion by scaling CO_2 emissions from CO emissions. Using a relatively conservative cost effectiveness criterion of $10,000/ton, and emission factors for external natural gas combustion from EPA's AP-42 emission factor database (84 and 120,000 lb/scf for CO and CO_2, respectively), a comparable cost-effectiveness criterion for CO_2 would be $7/ton (i.e., $10/000 x 84 / 120,000).

In October 2010, Hyperion Energy Center (a proposed combination oil refinery and integrated gasification combined-cycle power plant) submitted a greenhouse gas BACT analysis to South Dakota Department of Environment and Natural Resources in support of a renewal of a previously issued PSD permit that calculated the cost effectiveness of implementing Carbon Capture and Storage (CCS) on a CO_2 vent, refinery process heaters, and combined cycle gas turbines. The calculated cost effectiveness of the various control options ranged from $43 to $124 per ton of CO_2e. Absent any established cost effectiveness criteria, the Hyperion BACT analysis cited the Chicago Climate Exchange offset prices (less than $1 per ton at the time) and the EU allowance prices ($12 per tonne at the time) and concluded that CCS was not cost effective. South Dakota has not yet renewed the PSD permit for the Hyperion facility, and a contested case hearing is scheduled for July 25, 2011.

We Energies provided a GHG BACT analysis in support of a permit application submitted to Wisconsin Department of Natural Resources proposing to install and operate a biomass-fired boiler. The GHG BACT analysis included cost-effectiveness calculations for systems to control methane (CH_4) and nitrous oxide (N_2O), but did not provide any cost-effectiveness criteria for comparison.

Lacking specific guidance from EPA or local agencies, and weighting several sources that imply values less than $2/ton against an EU Allowance of $23/tonne, SPI proposes a GHG cost-effectiveness threshold of $7/ton, derived by scaling the commonly-accepted cost-effectiveness threshold for criteria pollutants ($10,000/ton) using natural gas combustion emission factors.

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2 Project Greenhouse Gas Emissions

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). The proposed facility has the potential to emit only four of these: 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 proposed facility has the potential to generate a maximum of approximately 1,213,500 tons of CO_2e per year.

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Table 2-1: Proposed Facility GHG Emissions

Emission Unit	Activity	Maximum Annual Operation (hr/yr)	GHG	Emission Factor[1]	Emission Rate[2] (lb/hr)	Emission Rate[2] (tpy)
PGU	2,350 MMBtu/hr	8,760	CO_2	117 lb/MMBtu	274,630	1,202,880
			CH_4	0.00220 lb/MMBtu	5.18	22.7
			N_2O	0.000220 lb/MMBtu	0.518	2.27
			CO_2e	--	274,899	1,204,060
Auxiliary Boiler	36.5 MMBtu/hr	4,380	CO_2	117 lb/MMBtu	4,266	9,343
			CH_4	0.00220 lb/MMBtu	0.08	0.176
			N_2O	0.000220 lb/MMBtu	0.008	0.0176
			CO_2e	--	4,271	9,353
Back-up Generator Diesel Engine	57.2 gal/hr	52	CO_2	22.5 lb/gal	1,287	33.5
			CH_4	0.000913 lb/gal	0.05	0.00136
			N_2O	0.000183 lb/gal	0.010	0.000271
			CO_2e	--	1,291	33.6
Emergency Fire Pump Diesel Engine	12 gal/hr	52	CO_2	22.5 lb/gal	270	7.02
			CH_4	0.000913 lb/gal	0.01	0.000285
			N_2O	0.000183 lb/gal	0.002	0.0000570
			CO_2e	--	271	7.04
Circuit Breakers	161 lb SF_6/unit[4]	3 units	SF_6	1% leakage/year/unit[5]	0.000551	0.00242
			CO_2e		13.2	57.7
Total	--		CO_2	--	280,454	1,212,264
			CH_4		5.32	22.9
			N_2O		0.539	2.29
			SF_6		0.000551	0.00242
			CO_2e		280,746	1,213,511

1 The emission factors for combustion of natural gas (for the PGU 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 PGU as follows:
(274,630 lb CO_2/hr * 1 lb CO_2e/lb CO_2) + (5.18 lb CH_4/hr * 21 lb CO_2e/lb CH_4) + (0.518 lb N_2O/hr * 310 lb CO_2e/lb N_2O) = 274,630 lb CO_2e/hr + 108.8 lb CO_2e/hr + 160.6 lb CO_2e/hr = 274,899 lb CO_2e/hr

4 Quantity of SF_6 in a typical 230 kV-class circuit breaker.

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

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3 Power Generation Unit

The combustion turbine and the duct burner associated with HRSG that make up the PGU would combust pipeline natural gas exclusively. As indicated in the previous section, the PGU 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 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. While Step 1 is intended to include all possibilities, there are limits to the scope of the first two option categories (i.e., inherently low-emitting processes and clean fuels). As discussed in Section 1.2.1, the list of options in Step 1 need not include those that fundamentally redefine the nature of the proposed source or modification.

In the March 2011 Guidance document, USEPA 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. Regarding substitution of renewable electrical generation alternatives such as solar or wind technologies, not only would they constitute redefinition of the project, but the intermittent nature of those generation alternatives would compromise the renewable load-shaping intent of the project. As a result, no electrical generation technology other than natural gas-fired combined cycle combustion turbine systems are considered in the BACT analysis.

3.1.1 Carbon Dioxide

Carbon dioxide (CO_2) is a by-product of complete combustion. Altering the combustion process to reduce CO_2 emissions would increase emissions of "traditional" air pollutants such as carbon monoxide (CO) and volatile organic compounds (VOCs). Maximizing the combustion, heat transfer, and mechanical efficiencies of all equipment minimizes the quantity of fuel combusted, and therefore the quantity of CO_2 generated.

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.[1] Nevertheless, per the March 2011 Guidance, CCS technology is

1 Report of the Interagency Task Force on Carbon Capture and Storage, August 2010.

considered an available add-on control technology for reducing CO_2 emissions from fossil fuel-fired power plants.

3.1.2 Methane

Like carbon monoxide (CO) and volatile organic compounds (VOCs), methane (CH_4) emissions are the result of incomplete fuel combustion. In the case of natural gas, CH_4 emissions would result from fuel that escapes combustion due to improper mixing with oxygen or from being confined to a zone of relatively low temperature.

Proper combustion practices and use of properly designed equipment maximizes complete combustion, which minimizes formation of CH_4. Add-on controls used to remove CH_4 from gas streams include activated carbon adsorption systems and thermal or catalytic oxidation systems. Adsorption systems pass the gas stream though canisters filled with activated carbon, and the CH_4 is trapped in pores located on the carbon particles. When the carbon approaches saturation, the canister is replaced and processed to remove the CH_4, which is recovered or destroyed. Oxidation systems increase the temperature of the gas stream until the CH_4 oxidizes, forming CO_2 and water. Thermal oxidizers destroy CH_4 using a flame, while catalytic oxidation uses a catalyst to promote the oxidation reaction at a temperature lower than the combustion temperature of CH_4.

3.1.3 Nitrous Oxide

Unlike nitric oxide (NO), which is the product of high combustion temperatures (greater than 730 °C or 1,350 °F), nitrous oxide (N_2O) is the result of lower combustion temperatures (less than 800 °C or 1,475 °F). Its formation can be limited to some extent by using proper combustion techniques and properly designed combustion systems that promote complete combustion. Typically, conditions that favor CH_4 formation, also favor N_2O formation.

Add-on controls to reduce N_2O emissions include: non-selective catalytic reduction (NSCR), thermal destruction, and catalytic destruction. In the 1970s, NSCR systems were widely used to control N_2O (and NO_X) emissions from adipic and nitric acid production operations, but high energy costs reduced the popularity of this approach. Currently, NSCR systems have been used to reduce emissions from reciprocating engines operated in a rich-burn or stoichiometric mode. In general, NSCR systems pass the exhaust gases over catalysts, which use metals (e.g., platinum, rhodium, and palladium) to convert NO_X, CO, and VOCs to water, nitrogen, and carbon dioxide. Unburned hydrocarbons in the exhaust are used as a reducing agent to enable one catalyst to convert N_2O and NO_X, while CO and VOCs are oxidized by another catalyst. In cases where the option to consistently operate in a fuel-rich or stoichiometric mode to provide the reducing agent is not available, natural gas can be injected to act as the reducing agent.

Thermal destruction of N_2O is achieved using a reducing flame burner combusting premixed methane or natural gas. The flame temperature must be maintained high enough to destroy the N_2O, but below 1,500 °C to minimize NO_X formation. Catalytic destruction is accomplished at lower temperatures (400 to 700 °C) using metal- or zeolite-based N_2O-decomposing catalysts.

Conventional commercially-available selective catalytic reduction (SCR) systems (i.e., those using titanium, tungsten, and vanadium-based catalysts) used to reduce emissions of nitric

oxide (NO) and nitrogen dioxide (NO_2), as well as selective non-catalytic reduction (SNCR) systems, generate N_2O, so removal of such control systems would reduce N_2O emissions. However, at least two companies (BASF and Heraeus) have developed catalysts designed to simultaneously remove both N_2O as well as NO and NO_2.

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.

3.2.1 Carbon Dioxide

In Step 1, energy efficiency and CCS were identified as potential control technologies.

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.

Carbon Capture and Sequestration/Storage

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 PGU.

3.2.2 Methane

In Step 1, proper combustion, thermal oxidation, and catalytic oxidation were identified as possible alternatives for CH_4 reduction.

Proper Combustion

For natural gas-fired combustion turbines and boilers, proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon (including CH_4) emissions, therefore it is considered technically feasible for control of CH_4 emissions.

Thermal Destruction

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy CH_4 in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including CH_4. Because a thermal oxidizer has never been used to reduce CH_4 emissions from a combined-cycle combustion turbine, and it is not clear that use of such a system would result in a net reduction in CH_4 in the exhaust stream, this technology is considered technically infeasible for reducing CH_4 emissions from the proposed PGU.

Catalytic Destruction

When applied to combined-cycle combustion turbines, the intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC emissions. As discussed in the criteria pollutant BACT analysis submitted with the PSD permit application, the proposed PGU will employ an oxidation catalyst, which is considered technically feasible.

3.2.3 Nitrous Oxide

In Step 1, proper combustion, thermal destruction, catalytic destruction, NSCR, removal of SCR systems, and addition of N_2O-abating SCR systems were identified as possible alternatives for N_2O reduction.

Proper Combustion

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For natural gas-fired combustion turbines and boilers, proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon emissions, therefore it is considered technically feasible for control of N_2O emissions, though adjustments and techniques used to reduce CO and hydrocarbon emissions may not necessarily also reduce N_2O emissions.

Thermal Destruction

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy N_2O in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including N_2O. Because a thermal oxidizer has never been used to reduce N_2O emissions from a combined-cycle combustion turbine, and it is not clear that use of such a system would result in a net reduction in N_2O in the exhaust stream, this technology is considered technically infeasible for reducing N_2O emissions from the proposed PGU.

Catalytic Destruction

When applied to combined-cycle combustion turbines, the intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC emissions. As discussed in the criteria pollutant BACT analysis submitted with the PSD permit application, the proposed PGU will employ an oxidation catalyst, which is therefore considered technically feasible.

Non-Selective Catalytic Reduction Systems

NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations, though they are also employed to reduce both NO_X and N_2O emissions from reciprocating engines. To achieve emission reductions from a reciprocating engine, the engine must be operated in a fuel-rich mode (i.e., less than 4 percent oxygen). Because combustion turbines operate with high levels of excess air (i.e., approximately 15 percent oxygen), NSCR is considered technically infeasible for control of N_2O from the proposed PGU.

Removal of Conventional Selective Catalytic Reduction Systems

The proposed PGU will employ an SCR system to reduce NO_X emissions. Removal of the SCR system is technically feasible.

Addition of N_2O-Abating Selective Catalytic Reduction Systems

Catalyst systems that employ ammonia injection to achieve reductions in both NO_X and N_2O are under development for application to exhausts from nitric acid and adipic acid plants. In addition to being the developmental phase, there is no indication that the technology could be applied to combined-cycle combustion turbines; therefore, the technology is considered technically infeasible for application to the proposed PGU.

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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. 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.

Proper Combustion/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 PGU will be capable of achieving a net efficiency of between 49.5 and 57.5 percent, and a net heat rate of between 5,930 and 6,887 British thermal units per kilowatt-hour (Btu/kWh), depending upon the operational mode and ambient conditions. Operating at maximum load with duct firing, under design conditions, the net efficiency is expected to be 55.7 percent, and the net heat rate is expected to be 6,158 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)
Kalama Energy Center	Proposed	346	57.5%
CPV Vaca Station Power Plant	Pending (Y-SAQMD)	660	55%
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%
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)

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As shown in Table 3-1, the maximum efficiency of the proposed project is greater than that of any recently permitted project. Of the projects listed, only Russell Energy Center (voluntarily) and Kalama Energy Center underwent GHG BACT analyses (Avenal Energy was grandfathered by EPA). The maximum permitted heat rate of each turbine at Russell Energy Center is 7,730 Btu/kWh, while the maximum heat rate of the proposed PGU will be 6,988 Btu/kWh. On a per-MWh (net) basis, Russell Energy Center will emit a maximum of approximately 920 lb of CO_2, while the proposed PGU will emit a maximum of approximately 795 lb CO_2e/MWh (net). It should be noted that this 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). All commonly-used efficiency and GHG emission metrics indicate that the proposed PGU is the most efficient currently available.

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.

Catalytic Destruction

Catalysts are a notoriously ineffective means of destroying CH_4 at typical exhaust temperatures (i.e., less than 700 °C), and the low availability of oxygen in combustion exhaust would further degrade the effectiveness. At best, a 20 percent reduction in CH_4 emissions has been documented when applied to internal combustion engines.

When applied to exhaust from an adipic acid operation, catalytic destruction systems are effective, reducing N_2O emissions by up to 95 percent. Although it is unclear that the same reductions would be realized when similar catalysts are applied to a combined-cycle combustion turbine exhaust stream, the stated levels of control will be assumed valid. The catalyst would

have no effect on CO_2 in the exhaust. Applying these catalysts together would result in a potential GHG emission reduction of, at most, 0.06 percent on a CO_2e basis.

Removal of NO_X Control System (SCR)

Conversion of NO_X to N_2O by SCR systems is typically less than 5 percent, and never greater than 8 percent. In most state-of-the-art applications, the conversion rate is below 1 to 2 percent.[2] SCR systems do not generate any CO_2 or CH_4, so elimination of the system would not affect concentrations of these compounds in the exhaust gas. Assuming the SCR system accounts for all of the N_2O generated by the PGU (a conservative assumption), and that removal of the SCR system would eliminate all N_2O emissions, the reduction in GHG emissions associated with removal of the SCR system would be 0.06 percent on a CO_2e basis.

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
- Catalytic Destruction – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Removal of NO_X Control System (SNCR) – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Proper Combustion/Energy Efficiency – Baseline

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

In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where the options are considered and either eliminated or adopted in order of effectiveness, the economic, energy, and environmental impacts of all options are considered. In light of this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

Carbon Capture and Sequestration/Storage

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.

2 Grosso, Mario and Lucia Rigamonti. Experimental Assessment of N_2O Emissions from Waste Incineration: The Role of NO_X Control Technology. Politecnico di Milano – DIIAR – Environmental Section.

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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 $63 per ton.[3] This is almost ten times the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2, even without accounting for the economy of scale realized by a 555 MWe unit as compared to that of a 346 MWe unit. 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, the heat input would be increased to achieve a net power output equivalent to the 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.

Catalytic Destruction

Because a catalyst would reduce emissions of GHGs other than CO_2, it is estimated to reduce GHG emissions, on a CO_2e basis, by less than 800 tons per year as the treated GHGs represent a minute fraction of the overall emissions. In order to be considered cost effective, and assuming the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2, the annual cost of each system would have to be less than $5,500 annually, which is unlikely, based on the costs of catalytic systems used to reduce criteria pollutants. Based on the criteria pollutant analysis, catalytic oxidation is considered BACT for CO and VOC emissions, and will be installed to reduce emissions of those pollutants, but because reductions in CH_4 and N_2O emissions are likely to be minimal and therefore not cost effective, the system is not considered to be BACT for reducing GHG emissions.

Removal of NO_X Control System (SCR)

The criteria pollutant BACT analysis proposes SCR as BACT for NO_X emissions from the PGU. Elimination of the SCR system would increase NO_X emissions by at least 2.5 times to achieve a 0.06 percent decrease in GHG emissions. The collateral increase in NO_X emissions is considered unacceptable, and elimination of the SCR system is removed from consideration as BACT for GHG emissions from the proposed PGU.

Proper Combustion/Energy Efficiency

Utilizing an efficient design and operating the PGU to produce the maximum quantity of electricity per unit of fuel combusted are control alternatives that ENW proposes to incorporate

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.

in the project. As stated previously, these options are considered the baseline for the BACT analysis, and all other options were considered to be applied over and above these two. These alternatives have a positive energy and environmental, and most likely economic, impact, and are considered to be BACT for GHG emissions from the proposed PGU.

The PGU will feature the Siemens SGT6-5000F(4) combustion turbine, which is capable of generating up to 232 MW, and is the most efficient unit (up to 57.5 percent) available in its class. Siemens and GE both offer units with efficiencies approaching 60 percent, but they are larger units not suitable for use in the proposed PGU. A larger unit, producing approximately 300 MW or more, would necessitate use of a smaller steam turbine for the net power production of the PGU to remain under the 350 MW threshold, which would reduce the overall efficiency of the PGU.

3.5 Step 5 – Selection of BACT

Based on the analysis presented here, ENW proposes that BACT for GHGs from the proposed PGU is energy-efficient system design and proper combustion practices. ENW proposes a 12-month rolling average GHG emissions limit of 1,204,060 tons of CO_2e per year (ton CO_2e/yr). In addition, ENW proposes to maintain the PGU such that the net heat rate does not exceed 7,788 British thermal units per kilowatt-hour (Btu/kWh) on a 12-month rolling average. The mass emission limit is based on continuous operation at 100 percent load with duct firing, and the heat rate limit is based on a presumed worst-case operating scenario as outlined in Table 3-2. The facility will almost certainly not operate continuously, nor as described in Table 3-2, but in a manner that lies somewhere between those two extremes.

Table 3-2: PGU GHG BACT Limit Calculations

Operating Mode	Net Power (kW)	Annual Operating Period (hr/yr)	Annual Fuel Input (MMBtu/yr)	Annual Net Power Output (kWhr/yr)
Normal[1]	346,000	4,060	9,539,041	1,404,760,000
Reduced Load[2]	177,200	4,000	5,260,207	708,800,000
Startup & Shutdown[3]	0	700	876,861	0
Total	--	8,760	15,676,109	2,113,560,000
Ideal Total Annual Heat Rate[4]			7,417	Btu/kWhr
Degradation Factor (5%)[5]			371	Btu/kWhr
Actual Total Annual Heat Rate[6]			7,788	Btu/kWhr

1 100% load with duct firing at design conditions
2 50% load with duct firing at 60 °F ambient temperature
3 Fuel use based on manufacturer information for warm startup and shutdown from 100% load
4 Ideal Total Annual Heat Rate = Annual Fuel Input / Annual Net Power Output
5 Assumed maximum degradation in year immediately preceding maintenance
6 Actual Total Annual Heat Rate = Ideal Total Annual Heat Rate x (1 + Degradation Factor)

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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 50 percent of the time on an annual basis.

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 Carbon Dioxide

CO_2 is a by-product of complete combustion. 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 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. As discussed in the PGU BACT analysis, the only add-on control available to reduce CO_2 is CCS.

4.1.2 Methane

Methane emissions from a natural gas-fired boiler are the result of fuel that is not combusted. Proper combustion practices and properly designed equipment can minimize CH_4 emissions by ensuring a sufficient combustion temperature and adequate mixing of fuel with combustion air. Add-on control systems include thermal oxidizers which destroy VOC using a flame, and oxidation catalysts which promote oxidation of VOCs at temperatures lower than the normal combustion temperature.

4.1.3 Nitrous Oxide

Low combustion temperatures favor creation of N_2O. As for CH_4, proper combustion practices and properly designed equipment can minimize N_2O emissions by ensuring a sufficient combustion temperature and adequate mixing of fuel with combustion air. Add-on controls for reducing N_2O emissions include: NSCR, thermal destruction, and catalytic oxidation. To reduce N_2O emissions created by combustion (as opposed to that created by adipic or nitric acid production operations) a catalyst uses unburned hydrocarbons in the exhaust to reduce the N_2O. Thermal destruction uses a reducing flame to destroy N_2O, while catalytic destruction uses catalysts to decompose N_2O at flue gas temperatures. While not an add-on control per se, conventional SCR systems used to reduce NO_X emissions create a small amount of N_2O, so removal of an SCR system would reduce N_2O emissions. There are also SCR systems under development for nitric acid and adipic acid plants that use injected ammonia to reduce both NO_X and N_2O.

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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.

4.2.1 Carbon Dioxide

In Step 1, use of energy efficiency, use of a low-carbon fuel, and CCS were identified as potential control technologies.

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.

Carbon Capture and Sequestration/Storage

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.

4.2.2 Methane

In Step 1, proper combustion, thermal oxidation, and catalytic oxidation were identified as possible alternatives for CH_4 reduction.

Proper Combustion

For natural gas-fired boilers, proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon (including CH_4) emissions, therefore it is considered technically feasible for control of CH_4 emissions.

Thermal Destruction

To thermally oxidize a pollutant in an exhaust stream, a combustor is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support a flame are introduced. While the thermal oxidizer may destroy CH_4 in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including CH_4. Because a thermal oxidizer has never been used to reduce CH_4 emissions from a natural gas-fired boiler, and it is not clear that use of such a system would result in a net reduction in CH_4 in the exhaust stream, this technology is considered technically infeasible for reducing CH_4 emissions from the proposed auxiliary boiler.

Catalytic Destruction

The intent of a catalytic oxidation system is to reduce CO and, to a lesser extent, VOC (including CH_4) emissions. Catalytic oxidation is frequently applied to combustion units with

relatively high excess oxygen levels, such as combustion turbines (12 to 15 percent excess O_2). Natural gas-fired boilers have much lower oxygen levels (4 to 6 percent O_2), which limits the effectiveness of the catalyst. Furthermore, low-molecular weight compounds, such as CH_4, are not easily oxidized by catalysts. Nevertheless, use of an oxidation catalyst to reduce CH_4 emissions is considered technically feasible.

4.2.3 Nitrous Oxide

In Step 1, proper combustion, thermal destruction, catalytic destruction, NSCR, removal of SCR systems, and addition of N_2O-abating SCR systems were identified as possible alternatives for N_2O reduction.

Proper Combustion

Proper combustion is a ubiquitous control technology used to reduce CO and hydrocarbon emissions from natural gas-fired boilers, and, therefore, it is considered technically feasible for control of N_2O emissions, though adjustments and techniques used to reduce CO and hydrocarbon emissions may not necessarily also reduce N_2O emissions.

Thermal Destruction

To thermally reduce a pollutant in an exhaust stream, a combustor with a reducing flame is located in the exhaust duct, and fuel (typically natural gas) and enough supplemental air to support the flame are introduced. While the reducing flame may destroy N_2O in the exhaust, the combustor itself will generate a certain quantity of air pollutants, including N_2O. Because a thermal oxidizer has never been used to reduce N_2O emissions from a natural gas-fired boiler, and it is not clear that use of such a system would result in a net reduction in N_2O in the exhaust stream, this technology is considered technically infeasible for reducing N_2O emissions from the proposed auxiliary boiler.

Catalytic Destruction and Non-Selective Catalytic Reduction Systems

NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations, though they are also employed to reduce both NO_X and N_2O emissions from reciprocating engines. To achieve emission reductions from a reciprocating engine, the engine must be operated in a fuel-rich mode to provide hydrocarbons to use as a reducing agent. Natural gas-fired boilers are operated using proper combustion practices, which attempts to minimize unburned hydrocarbons in the exhaust. Furthermore, catalytic reduction systems have never been used on a natural gas-fired boiler, and it is unclear that such a system would reduce N_2O emissions from such a boiler. Catalytic reduction systems, including NSCR, are considered technically infeasible for control of N_2O emitted by the proposed auxiliary boiler.

Removal of Conventional Selective Catalytic Reduction Systems

The proposed auxiliary boiler will not employ a conventional SCR system to reduce NO_X emissions. Because no SCR system is intended, removal of such a system is technically infeasible for application to the proposed auxiliary boiler.

Addition of N_2O-Abating Selective Catalytic Reduction Systems

Catalyst systems that employ ammonia injection to achieve reductions in both NO_X and N_2O are under development for application to exhausts from nitric acid and adipic acid plants. In addition to being the developmental phase, there is no indication that the technology could be applied to natural gas-fired boilers; therefore, the technology is considered technically infeasible for application to the proposed auxiliary boiler.

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.

Proper Combustion/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.

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.

Catalytic Destruction

Catalysts are a notoriously ineffective means of destroying CH_4 at typical exhaust temperatures (i.e., less than 700 °C), and the low availability of oxygen in combustion exhaust would further degrade the effectiveness. At best, a 20 percent reduction in CH_4 emissions has been documented when applied to internal combustion engines. Although it is unclear that the same reduction would be realized when a similar catalyst is applied to a natural gas-fired boiler, the stated levels of control will be assumed valid. Catalysts would have no effect on CO_2 in the exhaust, and is assumed to have little or no effect on N_2O concentrations as well. Applying an oxidation catalyst would result in a potential GHG emission reduction of, at most, 0.06 percent on a CO_2e basis.

Removal of NO_X Control System (SNCR)

SNCR systems convert, depending upon the reagent and furnace conditions, between 10 and 20 percent of NO_X in the exhaust to N_2O. SNCR systems do not generate any CO_2 or CH_4, so elimination of the system would not affect concentrations of these compounds in the exhaust gas. Assuming the SNCR system accounts for all of the N_2O generated by the boiler, and that removal of the SNCR system would reduce N_2O emissions to zero, the reduction in GHG emissions would be 0.06 percent on a CO_2e basis.

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
- Catalytic Destruction – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Removal of NO_X Control System (SNCR) – 0.06 percent reduction in emitted GHGs on a CO_2e basis
- Proper Combustion/Energy Efficiency – Baseline

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

In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where options are considered and either eliminated or adopted in decreasing order of effectiveness, the economic, energy, and environmental impacts of all options be considered. In light of this guidance, each technically feasible option was evaluated, regardless of the Step 3 ranking.

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Carbon Capture and Sequestration

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 over ten times the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2, even without accounting for the economy of scale realized by a 550 MWe unit as compared to that of a 40 MMBtu/hr unit (which could potentially generate approximately 4 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.

Catalytic Destruction

Because this alternative would potentially reduce emissions of only CH_4, it is estimated to reduce GHG emissions, on a CO_2e basis, by less than 700 tons per year. In order to be considered cost effective, and assuming the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2, the annual cost of each system would have to be less than $4,900 annually, which is unlikely, based on the costs of catalytic systems used to reduce criteria pollutants.

Similarly, the economic analysis provided in the criteria pollutant BACT analysis for a catalytic oxidation system to reduce CO emissions indicated that the economic impact of an oxidation catalyst would be unacceptable. Because the GHG reduction associated with these systems (on a percent basis) is less than the expected reduction in CO associated with an oxidation catalyst system, and the BACT cost-effectiveness threshold for GHGs is lower than what is typical for CO, this alternative is considered to have an unacceptably high collateral economic impact.

As a result of the economic impacts, catalytic destruction is removed from consideration as BACT for GHG emissions from the proposed auxiliary boiler.

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

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Proper Combustion/Energy Efficiency

Utilizing an efficient boiler design, operating the boiler to produce the most steam and electricity per unit of fuel combusted, and use of a low-carbon fuel are control alternatives that ENW proposes to incorporate in the auxiliary boiler. As stated previously, these options are considered the baseline for the BACT analysis, and all other options were considered to be applied over and above these two. These alternatives have a positive energy and environmental, and most likely economic, impact, and are considered to be BACT for GHG emissions from the proposed auxiliary boiler.

4.5 Step 5 – Selection of BACT

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

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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 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, the engines will each operate an hour per week for maintenance and testing (i.e., 52 hours per year).

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.

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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, ENW 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 – Caterpillar Standby 800 ekW 1000 kVA
- Emergency Firewater Pump Engine – Clarke JU6H-UFADR0

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6 High-Voltage Circuit Breakers

The switchyard that will be installed to interconnect the PGU to the electrical transmission system (the "grid") will include circuit breakers. Circuit breakers provide a means to isolate portions of the switchyard for service and to protect circuits from damage due to overload or short circuit conditions. ENW proposes to install 3 (three) 230 kV-class circuit breakers (maximum rated voltage 245 kV) 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 230 kV-class of 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, ENW 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 230 kV class (245 kV maximum rating).

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Appendix D:
Ozone Impact Analysis

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7.2 What if scenario - No lower Columbia River point sources

Following the 2015 managed growth maintenance projection, a 'what-if' control scenario was formulated for analysis. The scenario assumed no lower Columbia River point sources. This effectively means no large industrial activity along the lower Columbia River. Emissions comparisons between the 2015 case and the no lower Columbia River point source case are shown in Table 14. There is a 6% reduction in VOC emissions and an 11% reduction in NOx emissions due to the removal of the lower Columbia River point sources.

Table 14. Anthropogenic emissions comparisons between the 2015 managed growth maintenance projection and the no lower Columbia River point source case.

	2015 projection	2015 no_columbia_pt	Percentage change
	Mole/day	Mole/day	
VOC	924	870	-6%
NOX	875	779	-11%
SOX	99	55	-44%
CO	19455	19046	-2%
VOC/NOx	1.06	1.12	6%

Note: Emissions are daily averages (July 24 –29) summed over the central domain (grid cells 10,20 to 45,55)

Simulated ozone contours for the 2015 managed growth maintenance projection, the no lower Columbia River point source case, and the difference plots are shown in Figure 35a-c. Simulated 1-hr and 8-hr surface ozone concentrations for the two cases are shown in Figure 36 for the sites with large ozone changes. A summary of VOC/NOx emission ratios and predicted 8-hr daily maximum ozone (from the surrounding 5x5 grids) for 1998 episode, 2015 managed growth maintenance projection, and 2015 no lower Columbia River point sources modification are shown in Table 15 and Figure 37.

The amount of O3 reduction is up to 16 ppb for the case with no lower Columbia River point sources. The maximum reduction does not occur in the same region as the peak ozone is predicted to occur, and therefore the maximum ozone in the Portland/Vancouver airshed is not affected. The most affected sites are at Woodland and Sauvie Island where up to a 12 ppb decrease was predicted for the afternoon of June 26. At these two sites, there was also some increase in ozone at night due to less NO titration. At Mt View and Milwaukie, a small reduction was predicted, but not at the peak ozone hours. At the other sites, the changes in O3 concentrations were almost negligible.

Further analysis of other potential control strategies, based upon modifications to the 2015 managed growth maintenance projection, will be conducted by ODEQ and SWCAA as part of the overall maintenance plan development.

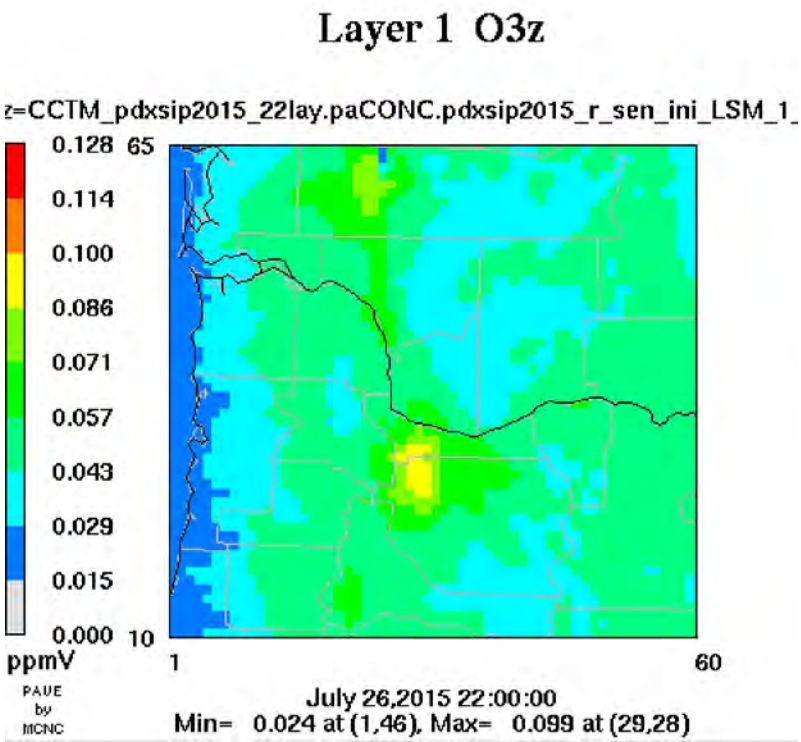


Figure 35a. Simulated ozone contour for 2015 no lower Columbia River point source case at 15 PDT on July 26

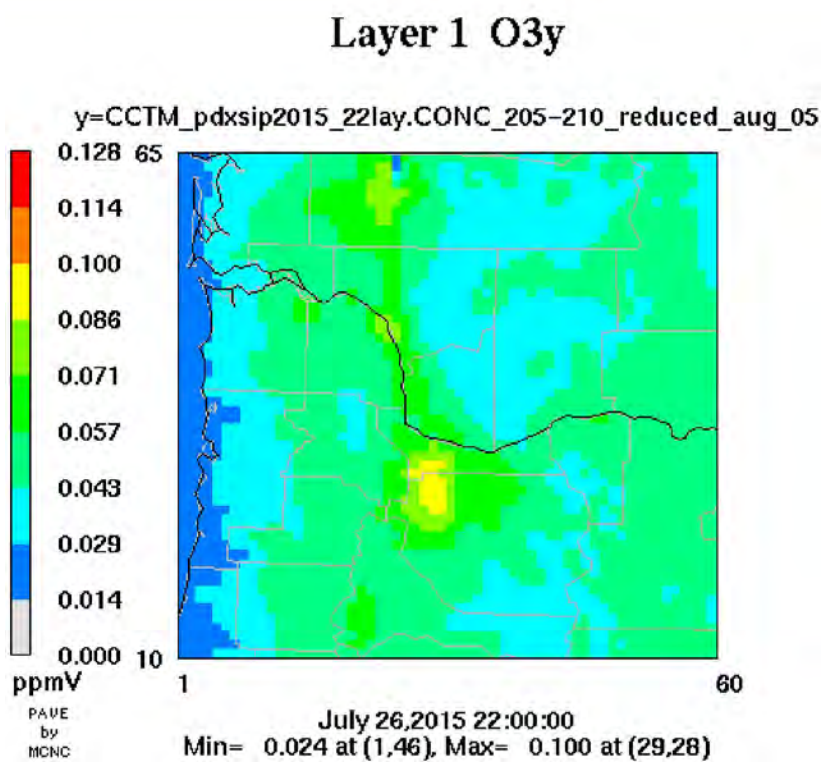


Figure 35b. Simulated ozone contour for 2015 projection at 15 PDT on July 26

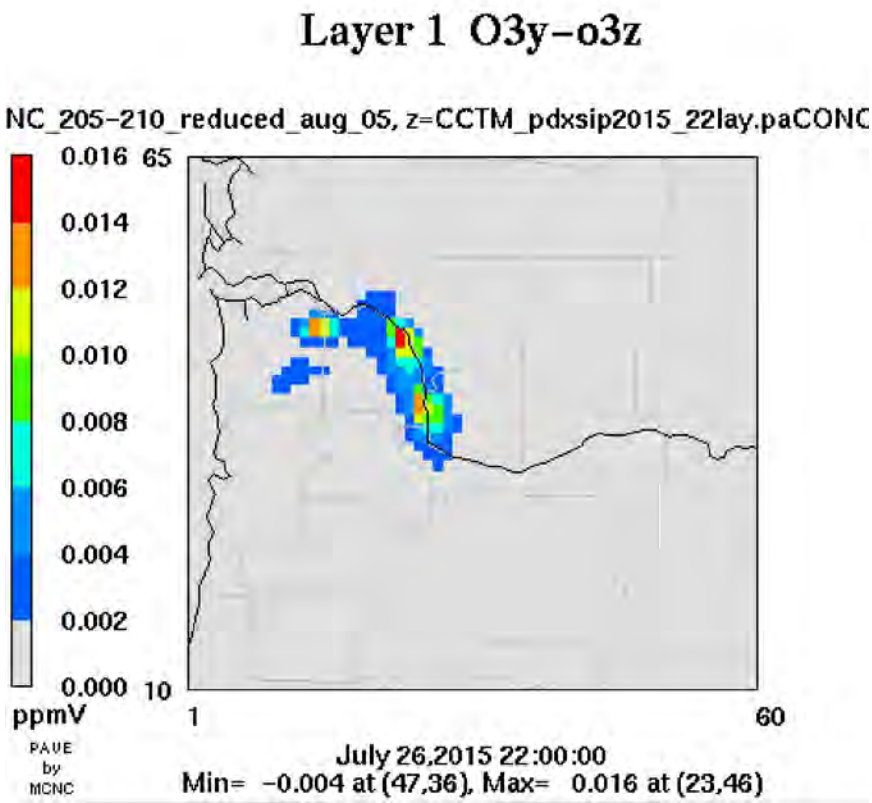
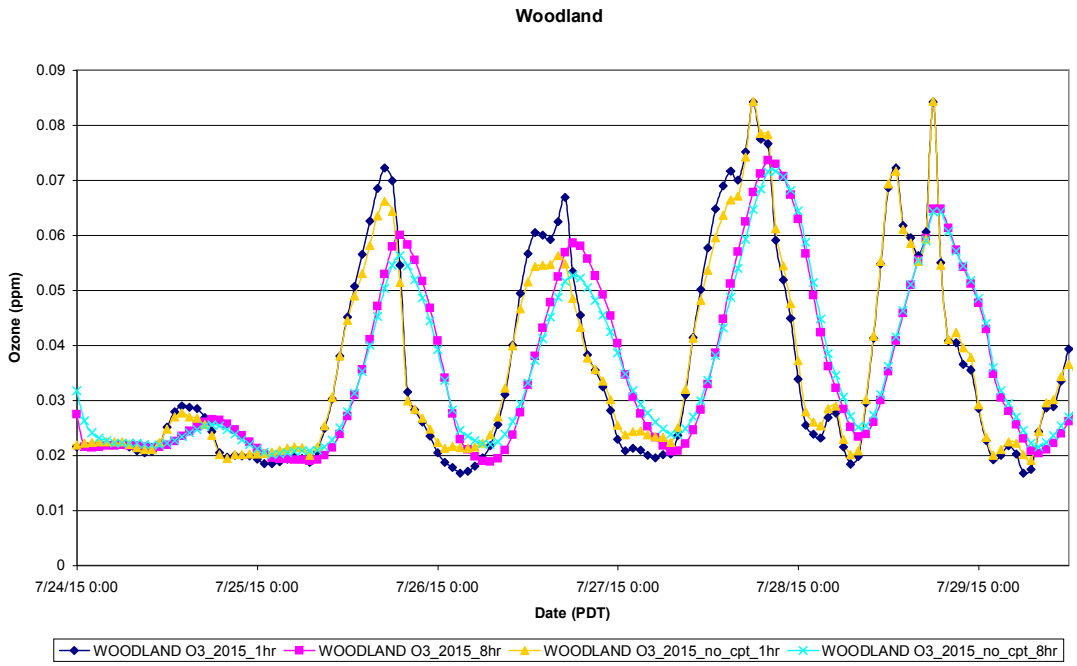
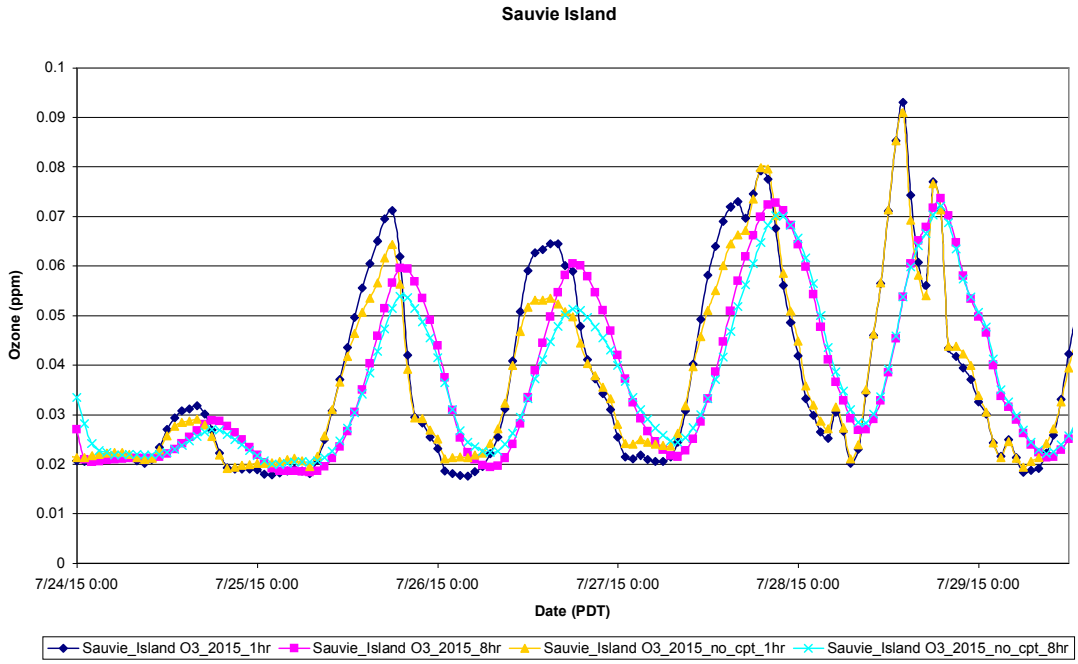
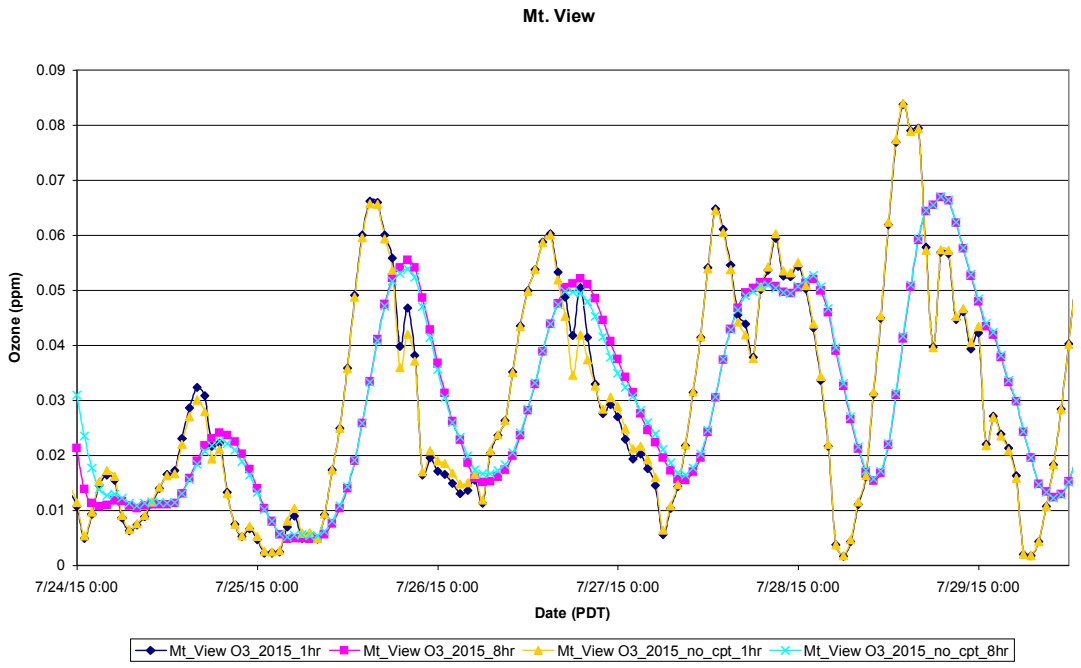


Figure 35c. Ozone difference plots between the 2015 managed growth maintenance projection and its no Lower Columbia River point sources modification at 15 PDT on July 26, 2015
(2015 – no Lower Columbia point sources)

Figure 36. Simulated 1-hr and 8-hr surface ozone concentrations for the 2015 managed growth maintenance projection and its no lower Columbia River point sources modification.






Mt. View
Ozone (ppm)
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
7/24/15 0:00
7/25/15 0:00
7/26/15 0:00
7/27/15 0:00
7/28/15 0:00
7/29/15 0:00
Date (PDT)
Mt_View O3_2015_1hr
Mt_View O3_2015_8hr
Mt_View O3_2015_no_cpt_1hr
Mt_View O3_2015_no_cpt_8hr

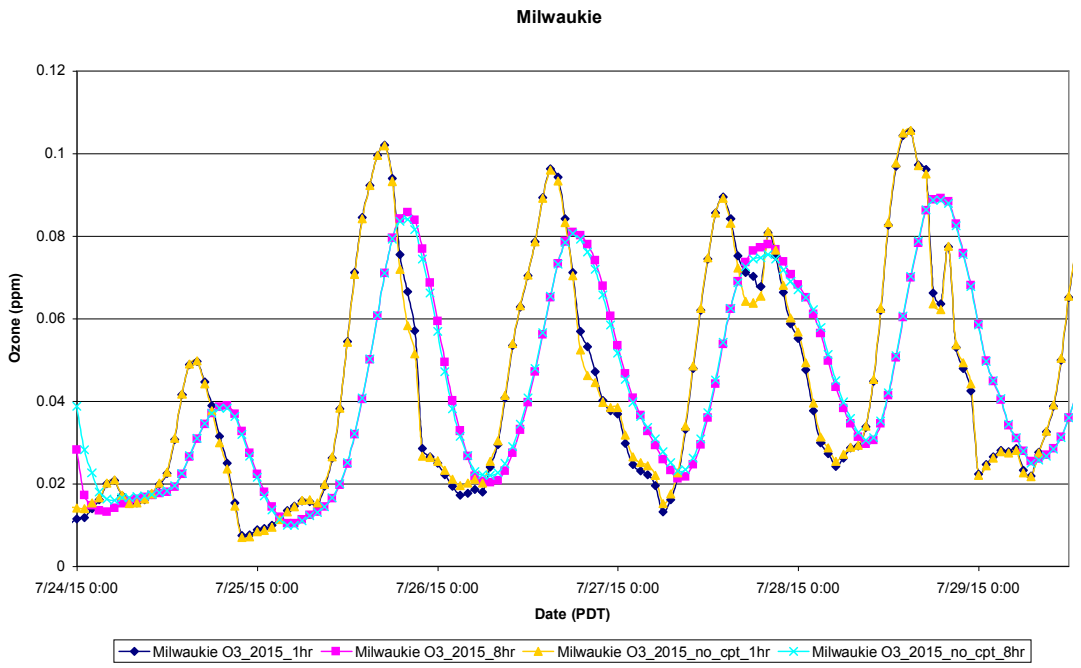

Milwaukie
Ozone (ppm)
0.12
0.1
0.08
0.06
0.04
0.02
0
7/24/15 0:00
7/25/15 0:00
7/26/15 0:00
7/27/15 0:00
7/28/15 0:00
7/29/15 0:00
Date (PDT)
Milwaukie O3_2015_1hr
Milwaukie O3_2015_8hr
Milwaukie O3_2015_no_cpt_1hr
Milwaukie O3_2015_no_cpt_8hr

Table 15. VOC/NOx ratio and predicted 8-hr daily maximum ozone (from the surrounding 5x5 grids) for 1998 episode, 2015 projection, and 2015 no lower Columbia River modification.

		1998 base	**2015 base**	**2015 no_Columbia_pt**
VOC/NOx		0.73	1.06	1.12
Site	Date	Pre 8-hr daily max 5x5 (ppm)	Pre 8-hr daily max 5x5 (ppm)	Pre 8-hr daily max 5x5 (ppm)
Castle Rock	26-Jul	0.075	0.060	0.060
Castle Rock	27-Jul	0.091	0.077	0.077
Castle Rock	28-Jul	0.079	0.068	0.068
Woodland	26-Jul	0.073	0.062	0.057
Woodland	27-Jul	0.091	0.075	0.073
Woodland	28-Jul	0.083	0.072	0.072
Sauvie_Island	26-Jul	0.070	0.061	0.054
Sauvie_Island	27-Jul	0.090	0.073	0.071
Sauvie_Island	28-Jul	0.087	0.075	0.074
Mt_View	26-Jul	0.076	0.071	0.070
Mt_View	27-Jul	0.086	0.072	0.069
Mt_View	28-Jul	0.088	0.082	0.081
Milwaukie	26-Jul	0.086	0.084	0.084
Milwaukie	27-Jul	0.091	0.085	0.084
Milwaukie	28-Jul	0.098	0.095	0.095
Carus	26-Jul	0.090	0.077	0.077
Carus	27-Jul	0.097	0.085	0.084
Carus	28-Jul	0.107	0.095	0.095
Turner	26-Jul	0.074	0.060	0.059
Turner	27-Jul	0.101	0.078	0.076
Turner	28-Jul	0.089	0.068	0.068
Wishram	26-Jul	0.055	0.050	0.052
Wishram	27-Jul	0.056	0.049	0.050
Wishram	28-Jul	0.059	0.050	0.051
Hockinson	26-Jul	0.062	0.050	0.049
Hockinson	27-Jul	0.069	0.059	0.059
Hockinson	28-Jul	0.075	0.064	0.065
	mean	**0.081**	**0.070**	**0.069**
	max	**0.107**	**0.095**	**0.095**
	min	**0.055**	**0.049**	**0.049**

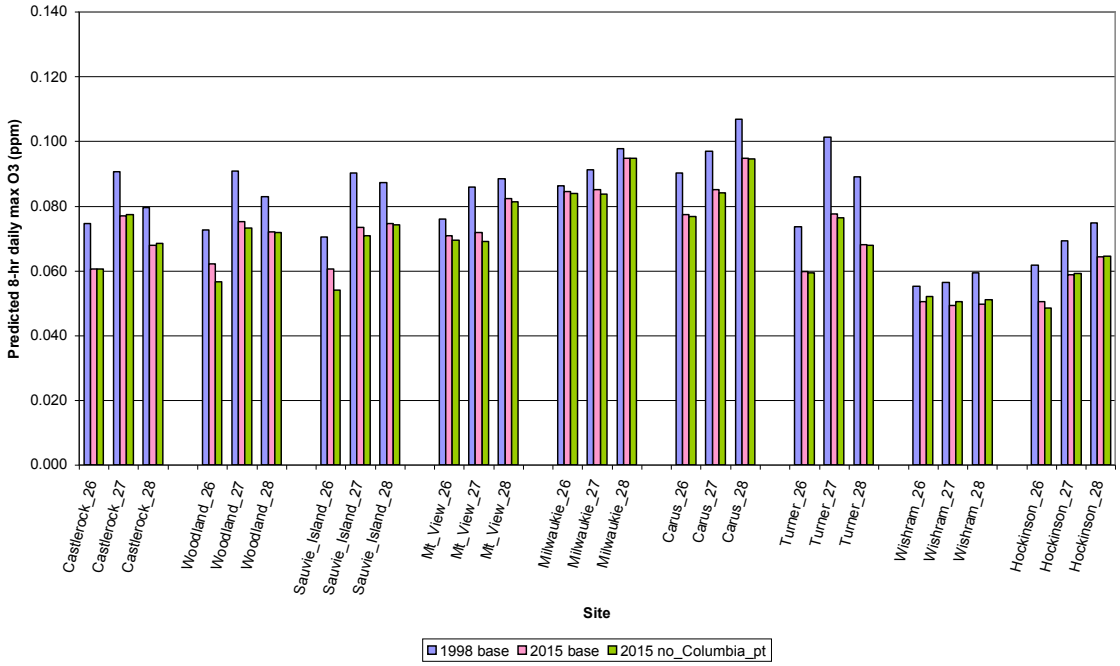


Figure 37. Predicted 8-hr daily maximum ozone (from surrounding 5x5 grids) for 1998 episode, 2015 managed growth maintanence projection, and 2015 no lower Columbia River point source modification.

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Appendix E:
Greenhouse Gas Emission
Rate Calculations for
Emission Performance
Standard and Mitigation Fee

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Greenhouse Gas (GHG) Calculations

GHG Emission Performance Standard (RCW 80.80)

Maximum heat input	2,350	MMBtu/hr	Design conditions from Siemens
CO_2 emission factor	53.02	kg CO_2/MMBtu	From 40 CFR Part 98, Table C-1
CH_4 emission factor	1.00E-03	kg CH_4/MMBtu	From 40 CFR Part 98, Table C-2
N_2O emission factor	1.00E-04	kg N_2O/MMBtu	From 40 CFR Part 98, Table C-2
Maximum annual hours of operation	8,760	hr/yr	
Maximum potential CO_2 emissions	1,091,246	tonnes CO_2/yr	
Maximum potential CH_4 emissions	20.6	tonnes CH_4/yr	
Maximum potential N_2O emissions	2.1	tonnes N_2O/yr	
Global Warming Potential - CO_2	1		From 40 CFR Part 98, Table A-1
Global Warming Potential - CH_4	21		From 40 CFR Part 98, Table A-1
Global Warming Potential - N_2O	310		From 40 CFR Part 98, Table A-1
Maximum potential CO_2 emissions	1,091,246	tonnes CO_2e/yr	
Maximum potential CH_4 emissions	432	tonnes CO_2e/yr	
Maximum potential N_2O emissions	638	tonnes CO_2e/yr	
Total GHG Emission Rate	1,092,316	tonnes CO_2e/yr	
Total GHG Emission Rate	2,408,119,570	lb CO_2e/yr	
GHG Emission Factor (CO_2e)	795	lb CO_2e/MW-hr	
GHG Emission Factor (mass of GHG)	794	lb GHG/MW-hr	

Carbon Dioxide Mitigation (RCW 80.70)

Total net generating capability	346.0	MWe	Design conditions from Siemens
Heat rate (HHV)	6,791,000	Btu/MWh	
Maximum heat input	2,350	MMBtu/hr	
Conversion factor	117.6	lb CO_2/MMBtu	From AP-42 Section 3.1, Table 3.1-2a
Maximum annual hours of operation	8,760	hr/yr	
Maximum potential CO2 emissions	1,097,972	tonnes CO_2/yr	
Total CO2 Emissions	19,763,505	tonnes CO_2	
Cogeneration Credit	0	tonnes CO_2	
Mitigation Quantity	3,952,701	tonnes CO_2	
CO2 mitigation cost	1.6	$/tonne	
Total CO2 mitigation cost	6,324,321	$	
Each of five payments	1,264,864	$	

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Appendix F: Compact Disc with Air Quality Dispersion Modeling Files

REVISED

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