DEPARTMENT OF
ECOLOGY
State of Washington

TECHNICAL SUPPORT DOCUMENT FOR PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT

PERMIT NO: PSD-11-04

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Kalama, Washington

Prepared by

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Submitted to

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EXECUTIVE SUMMARY

Energy Northwest (ENW) proposes to construct and operate the Kalama Energy Center (KEC), a natural gas-fired combined cycle electrical generation station at the Port of Kalama. The facility would have a natural gas-fired combustion turbine-generator (CTG) and a steam turbine generator (STG) with an electrical output of approximately 346 megawatts electrical (MWe). The facility will have the capability to adjust its electrical power output to work in tandem with renewable energy sources like wind power.

The Washington State Department of Ecology (Ecology) received the Prevention of Significant Deterioration (PSD)/Notice of Construction (NOC) for the project on June 30, 2011, and the 30-day application completeness review period began on July 5. Ecology determined the application to be complete as of August 4, 2011. Additional information was received on October 3, 2011, November 3, 2011, December 8, 2011, and February 14, 2012.

Ecology has reviewed the application along with the additional information and found that the applicant has satisfied all requirements for a PSD permit approval based on the application. The following Technical Support Document (TSD) describes the project's emission units, the air emissions related to each unit, and the impact of these emissions on the environment as required by the PSD regulations. The TSD also discusses the emission limitations placed on the emissions from each unit, and the basis for establishing these limitations.

1. INTRODUCTION

1.1. The Permitting Process

1.1.1. The Prevention of Significant Deterioration Process

PSD permitting requirements in Washington State are established in the Washington Administrative Code (WAC) 173-400-700 through 750. These state regulations either adopt by reference or reflect the Federal EPA's PSD regulations in Title 40 Code of Federal Regulations (C.F.R.) § 52.21. The Washington State Department of Ecology's (Ecology) Air Quality Program has been delegated by the U.S. Environmental Protection Agency (EPA) the authority to conduct source review under the federal PSD regulations by an agreement dated November 17, 2011.

Federal and state rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent significant adverse environmental impact from emissions into the atmosphere by a proposed new major source or major modification to an existing major source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on visibility, soils, and vegetation. PSD rules also require the utilization of Best Available Control Technology (BACT) for certain new or modified emission units, which is the most effective air pollution control equipment and procedures that are determined to be available after considering environmental, economic, and energy factors.

1.1.2. The Notice of Construction Process

Kalama Energy Center is subject to Notice of Construction (NOC) permitting requirements for pollutants that are not PSD-applicable under the Southwest Clean Air Agency (SWCAA) 173-400 regulation. This includes air toxics issues under federal Maximum Achievable Control Technology (MACT) standards, state Chapter 173-460 WAC requirements, and also Title V permitting requirements. The procedure for issuing an NOC permit was established in Chapter 70.94 RCW.

SWCAA 173-400-110 (new source review) outlines the procedures for permitting criteria pollutants. These procedures are further refined in SWCAA 173-400-113 (requirements for new sources located in attainment or unclassifiable areas).

1.1.3. Federal Regulations Summary

The permit may not contain all the requirements included in the following summary. However, after the Title V and Acid Rain permits are issued, each of the following federal regulations will be addressed:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards (NSPS)	40 CFR 60, Subpart Dc
New Source Performance Standards (NSPS)	40 CFR 60, Subpart IIII
New Source Performance Standards (NSPS)	40 CFR 60, Subpart KKKK
NSPS Performance Specifications	40 CFR 60, Appendix B
NSPS Quality Assurance Procedures	40 CFR 60 Appendix F
Acid Rain Permitting	40 CFR 72
Emissions Monitoring and Permitting	40 CFR 75
Sulfur Content of Natural Gas to be monitored	40 CFR 60.4360, and 40 CFR 75, Appendix D
Greenhouse Gas Reporting	40 CFR 98 Subpart D

1.1.4. State Regulations Summary

This permit may not contain all the requirements included in the following summary. However, after the NOC, Title V, and Acid Rain permits are issued (by SWCAA), each of the following regulations will be addressed:

General Regulations for Air Pollution Sources	SWCAA 173-400 WAC
Operating Permit Regulations	Chapter 173-401 WAC
Acid Rain Regulations	Chapter 173-406 WAC
Carbon Dioxide Mitigation Program	Chapter 173-407 WAC
Controls For New Sources of Toxic Air Pollutants	Chapter 173-460 WAC

1.2. The Project

1.2.1. The Site

The Kalama Energy Center would be located on an approximately 16-acre site in Cowlitz County, Washington. 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 Kalama Energy Center is located in a Class II area that is designated as ―attainment or unclassifiable" for the purpose of PSD permitting for all pollutants.

1.2.2. The Kalama Energy Center Project

The Kalama Energy Center will be a new natural gas-fired, combined cycle, combustion turbine power plant. The Project is made up of the following components:

- One (1) combustion turbine generator (CTG)
- One (1) heat recovery steam generator (HRSG) with duct burners
- One (1) steam turbine generator (STG)
- One (1) auxiliary boiler
- Fuel supply
- Cooling system
- Fire protection
- Emergency generator

Combustion Turbine Generator (CTG)

A combustion turbine manufacturer has not been formally selected, but emission rate estimates are based on those of a Siemens model SGT6-5000F(4) combustion turbine. The generation facility is designed (at an annual average temperature of 54ºF) to produce 346 MWe using 2,350 million British thermal units per hour (MMBtu/hr) natural gas fuel. The turbine alone has a design heat input of 2,069 MMBtu/hr and its shaft and heat energy can produce a combined 312 MWe from the turbine's shaft driven generator combined with the turbine's hot gas heat energy supplied as steam by the HRSG to the steam turbine generator. The turbine will also have quick start and enhanced load following capability.

Heat Recovery Steam Generator with Duct Burners

The high temperature exhaust produced by the combustion turbine flows directly to a HRSG, which will produce output steam at three pressure levels, all of which will supply steam directly to the steam turbine. The HRSG will have supplemental duct firing of up to 281MMBtu/hr that can produce an additional 34 MWe at design temperature. The Selective Catalytic Reduction (SCR) control equipment for removal of nitrogen oxides (NO_X) and the oxidation catalyst for removal of carbon monoxide (CO) and volatile organic compounds (VOCs) are located within the HRSG.

Steam Turbine Generator (STG)

Steam from the HRSG will be delivered to a single STG, which will drive a generator with a gross capacity of approximately 150 MWe.

Auxiliary Boiler

An approximately 37 MMBtu/hr auxiliary natural gas-fired boiler will be installed with a low-NO_X burner (LNBs) to produce steam at approximately 25,000 pounds per hour (lb/hr) to provide sealing steam to the STG. It can also be used to maintain temperature in the HRSG during long idle time to reduce start-up duration.

Fuel Supply

The fuel for the Kalama Energy Center's turbine, duct burners, and auxiliary boiler will be natural gas only.

Cooling System

The proposed cooling system consists of a circulating water system that will carry cooled water from the cooling tower through the steam turbine condenser and back to the cooling tower. The evaporative cooling tower will consist of six (6) cells. A high efficiency drift eliminator with a maximum loss of 0.0005 percent of circulation flow will be installed.

Fire Protection

The fire protection system will provide the required fire protection for the Project. The fire water pump will be powered by a diesel engine sized at about 240 horsepower (hp), and will burn diesel fuel with less than 15 ppm sulfur content. It will be limited to 52 hours per year of non emergency operation, mostly for testing and maintenance. Emergency hours of operation are estimated to be a maximum of 275 hours per year. The power grid in this area is very stable though, and no actual emergency hours of operation at similar nearby power plants have been reported to Ecology.

Emergency Generator

An emergency generator of about 800 kilowatt (kW) will be installed to provide emergency power when power from the grid is not available. It will have a diesel engine sized at about 1,225 hp and will burn the same ultra low sulfur diesel fuel as the fire pump engine. It will be limited to 52 hours per year of nonemergency operation, mostly for testing and maintenance. Emergency hours of operation are estimated to be a maximum of 275 hours per year. The power grid in this area is very stable though, and no actual emergency hours of operation at similar nearby power plants have been reported to Ecology.

1.3. New Source Performance Standards

EPA 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 determined by BACT are virtually always lower.

Subpart A, General Provisions

Subpart A identifies a number of monitoring, recordkeeping, 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 start-up.

Consistent with NSPS requirements, ENW would notify Ecology and 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. ENW 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 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 on a 30 unit operating day basis, which includes start-up and shutdown emissions. The proposed NO_X exhaust concentration (2 ppmvd at 15 percent O_2) during normal operation and the power plant's quick start-up capability should keep monthly NO_X emissions well below the NSPS limit. Subpart KKKK limits SO_2 emissions to 0.90 lb/MWe-hr (equal to about 20 grains S/100scf), or 187 lb/hr for the proposed combustion turbine at maximum operating conditions. Estimated SO_2 emissions based on the local gas supply (analyzed at Northwest Pipeline's Sumas, WA, compressor station) are expected to be no more than 9.0 lb/hr. Test methods for NO_X and sulfur emissions are specified. It allows determination of daily sulfur emissions monitoring by keeping track of fuel sulfur content and usage. It allows development of a custom fuel-monitoring schedule that must be approved by the EPA Region 10. There are no NSPS requirements for CO, particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), or VOCs in Subpart KKKK.

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 36.5 MMBtu/hr.

Because the auxiliary boiler would be fired solely with natural gas, only the recordkeeping and reporting provisions of Subpart Dc apply. These requirements include maintaining records of daily fuel use, occurrence and duration of start-up, 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. PSD and Title V records retention policies often extend this recordkeeping requirement to five years.

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

Subpart IIII applies to the diesel-fired fire water pump engine and the backup 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 fire water 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 fire water pump engine are limited to 100 hr/yr of nonemergency operation (e.g., maintenance and testing). PSD permitting guidance recommends that an estimate of the expected emergency use hours per year be made, and the engine's emissions impacts be modeled for that number of hours.

1.4. Project Emissions and PSD Applicability

The Kalama Energy Project (Project) is permitted as a major source.[1] Annual emissions of a regulated pollutant[2] at levels considered significant[3] by the federal PSD regulations require permitting under the federal PSD program. As **Error! Reference source not found.** shows, NO_X, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ are all emitted in PSD significant quantities. Greenhouse gases are also emitted in PSD significant quantities. They are discussed in Sections 1.7 and 2.6. For natural gas and diesel fuel combustion, all particulates are very small, so for this project, PM, PM_{10}, and $PM_{2.5}$ are considered to be the same and all smaller than $PM_{2.5}$. All other PSD regulated pollutants (such as SO_2, sulfuric acid mist (H_2SO_4), H_2S, and lead) are either not emitted at all, or are emitted at less than PSD significant levels. If appropriate, they will be regulated by SWCAA's NOC permit.

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[1] Combined cycle turbines are considered part of the category ―Fossil fuel-fired steam electric plants." They are a major source under PSD regulations if they, in total, have the potential to emit more than 100 tons per year of a pollutant regulated by the PSD permitting program, 40 CFR 52.21(b)(1)(i)(a).

[2] The PSD program directly regulates a list of specific pollutants. These are referred to as ―regulated pollutants." The compounds listed in Table 1 are the regulated pollutants applicable to the Project. PSD regulates other pollutants indirectly through the broad categories of ―regulated" pollutants such as VOC and particulates. Greenhouse gases can now also make a project subject to PSD regulation, 40 CFR 52.21(b)(49). In Washington State, SWCAA issues a second permit (the Notice of Construction Approval, or NOC) that complements the PSD permit and includes all emissions regulated by state and local regulations, WAC 173-400-113.

[3] The PSD regulations list a minimum annual emission rate for each regulated pollutant to be considered ―significant" in 40 CFR 52.21(b)(23)(i). Some of these threshold levels are given in Table 1.

After the application of emission controls representing BACT or to protect ambient air quality, the Project is proposed to have annual criteria pollutant emissions as shown in Table 1. Short-term criteria pollutant emissions are shown Table 2.

Table 1. Facility-Wide Annual Criteria Pollutant Emissions Rates (TPY)

Source	NO_X	CO	SO_2	H_2SO_4	$PM/PM_{10}/PM_{2.5}$	VOC
Annual emission with continuous PGU operation						
PGU @ 100% load w/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 backup 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 start-ups 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 backup 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	40
PSD Review Required?	Yes	Yes	No	No	Yes	Yes

[1] 50% annual capacity factor.
[2] Maximum of 52 hr/yr of nonemergency operation.
[3] Total for 6-cell cooling tower.

Table 2. Maximum Short-Term Normal Operation Criteria Pollutant Emission Rates (lb/hr)

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 backup generator[1]	7.03	0.622	0.622	0.0149	0.0649	0.0812

Table 2. Maximum Short-Term Normal Operation Criteria Pollutant Emission Rates (lb/hr)						
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**
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 each in any given 24-hour period for testing and maintenance purposes.

1.5. Start-Up and Shutdown Emissions

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 start-ups 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. Its quick start design allows this combined cycle unit to start-up almost in the same time frames as a simple-cycle unit.

Table 3 identifies the expected duration of a combustion turbine start-up event as estimated by the turbine manufacturer, Siemens, and the quantity of air pollutants emitted during the event. The contribution of start-up and shutdown emissions to total annual emissions is given in Table 1. 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.

Since this new short start-up and shutdown technology is not well demonstrated in practice, the actual permit limits for start-up and shutdown duration times were extended to one hour for all start-up scenarios. Estimates of emissions per event were scaled proportionally. A review of modeled impacts of these increased emissions per event indicted that no short-term National Ambient Air Quality Standards (NAAQS) were threatened. KEC agreed to meet the originally estimated annual emissions, so this permit decision did not affect KEC's annual emissions. A maximum of 730 start-ups per calendar year were allowed. This averages to be two start-ups and shutdowns in a 24-hour period.

The calculated worst-case start-up/shutdown scenario emission rates indicate that the quantity of NO_X, CO, and VOC emitted during a start-up event is greater than during a similar period of normal operation; the quantity of PM emitted during a start-up event is comparable to, but slightly less than, a similar period of normal operation.

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

Table 3. Power Generation Unit Start-Up and Shutdown Data per Siemens[5]

Mode[1]	Time[2] (min)	Fuel Use[3] (lb/event)	Pollutant Emitted[4] (lb/event)			
			NO_X	CO	VOC	$PM/PM_{10}/PM_{2.5}$
"Cold" start-up	37	23,548	83	370	112	5.4
"Warm" start-up	37	26,900	85	220	88	5.9
"Hot" start-up	32	23,688	73	183	73	5.3
Shutdown from 100% load	37	39,906	37	69	28	7.3
Shutdown from 75% load	12	9,321	30	68	27	2.2

[1] Mode definitions: "Cold" start-up, >64 hr since shutdown; "Warm" start-up, 16–64 hr since shutdown; "Hot" start-up, <16 hr since shutdown.
[2] For start-ups, 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.
[5] Times and emissions in this table are as provided by the turbine manufacturer. For practical permitting purposes, because the start-up technology is not well demonstrated in practice, all event durations were given a 1-hour duration limit. Permitted short-term emissions per event were scaled up appropriately and their impacts evaluated against short-term NAAQS. No short-term NAAQS were threatened. Annual limits were kept the same as originally estimated.

As discussed several times earlier, emissions during start-up and shutdown periods are higher for some pollutants than during normal operation. The turbine's applicable NSPS requires a 30 operating day average NO_X limit in ppmvd or lb/MWh (not both). Also, some pollutant permit limits are larger for short-term emissions to account for variability, but lower for longer averaging periods, such as 30-day or 12-month rolling averages. Pollutant impacts have been modeled at these different short- and long-term averaging rates. To ensure compliance with the modeling, and for other reasons such as NSPS, the longer term emissions limits in Table 4 are included in the PSD permit.

Table 4. Longer Term Emission Limits on Individual Equipment

Pollutant	Emission Limit	Averaging Period
Combustion Turbine		
NO_X	15 ppmvd @ 15% O_2	30 operating day average, per 40 CFR Part 60, Subpart KKKK
	0.43 lb/MWh	30 operating day average, per 40 CFR Part 60, Subpart KKKK
	102.4 tpy	12-month rolling total
CO	131.1 tpy	12-month rolling total

Table 4. Longer Term Emission Limits on Individual Equipment		
Pollutant	**Emission Limit**	**Averaging Period**
VOC	47.8 tpy	12-month rolling total
$PM/PM_{10}/PM_{2.5}$	70.0 tpy	12-month rolling total
GHGs (CO_2e)	858 lb/MWh	12-month rolling average (BACT)
	1,204,060 tpy	12-month rolling total
Auxiliary Boiler		
GHG (as CO_2e)	9,353 tpy	12-month rolling total
Heat input	159, 870 MMBtu	12-month rolling total
Cooling Tower		
$PM/PM_{10}/PM_{2.5}$	3.9 tpy	12-month rolling total
Emergency Generator Engine		
GHG (as CO_2e)	33.6 tpy	12-month rolling total
Fire Pump Engine		
GHG (as CO_2e)	7.1 tpy	12-month rolling total

1.6. Toxic Emissions

Most toxic air pollutants (TAPs) that would be emitted by the Project are a subset of the criteria pollutant emissions listed in Table 1. This includes TAPs listed as federal hazardous air pollutants (HAPs) and those listed as Washington State TAPs. For example, most organic-type toxic compounds are included as a subset of VOC compounds. Toxic metal compounds emitted to air are a part of the $PM_{2.5}$.

The emission rates of individual TAPs are estimated and their impacts are evaluated as part of the ambient air quality analysis of the application. Toxic emissions will be regulated by SWCAA in the NOC permit they issue.

Ammonia would be used as part of the SCR NO_X control catalyst system. Ammonia is not a federal HAP, but is listed as a Washington State TAP. Ammonia emissions will be regulated by SWCAA in the NOC permit they issue.

1.7. Greenhouse Gas Emissions

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 backup 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 5 summarizes the GHG emission rate calculations; facility-wide potential to emit is approximately 1,214,000 tons of carbon dioxide equivalents (CO_2e) per year.

Table 5. Facility-Wide Greenhouse Gas Emission Rates

Emission Unit	Activity	Maximum Annual Operation (hr/yr)	GHG	Emission Factor[1]	Emission Rate[1] (lb/hr)	Emission Rate[1] (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
Backup 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 in each of 3 units[4]		SF_6	1% leakage/yr/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	0.00242

[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/gal emission factors were calculated using the 2.2046 lb/kg conversion factor.
[2] 100-yr 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 each individual GHG emission rate by the appropriate 100-yr time horizon 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. During permitting, the number of circuit breakers was increased to five.
[5] Worst-case expected leakage rate, based on current industry standard. The BACT process lowered the leakage rate to 0.5% per year. This change makes the project's final estimated SF_6 leakage slightly less than the original estimate shown here.

1.8. Shakedown Period

New electrical generation facilities must go through initial commissioning phases before becoming commercially available to generate electricity. This period typically continues until the successful completion of initial performance tests. During this period, emissions may be greater than those that occur during normal operations because of the need to tune the combustor, conduct numerous start-ups and shutdowns, operate under low loads, and conduct testing to ensure the safe, efficient, and reliable operation of the plant.

In the past, Washington has used enforcement discretion to allow emissions that were greater than normal operating limits during this shakedown period. For this permit, two conditions have been added to specifically allow these shakedown operations to occur while at the same time assuring that the plant operator makes every effort to minimize emissions and attempt to meet normal operating limitations. Condition X.C. provides for relief from normal operating emission limits during a shakedown period that ends upon successful initial performance testing, or 90 days after initial turbine start-up, whichever comes first. Condition X.A. requires that at all times the plant be operated in a manner consistent with good air pollution control practices for minimizing emissions.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

2.1. Definition and Policy Concerning BACT

All new sources are required to utilize Best Available Control Technology (BACT). BACT is defined as an emissions limitation based on the maximum degree of reduction for each pollutant subject to regulation, emitted from any proposed major stationary source or major modification, on a case-by-case basis, taking into account cost-effectiveness, economic, energy, environmental, and other impacts (40 CFR 52.21(b)(12)).

The "top down" BACT process is a five step process. The steps are:

1. Identify available control technologies.
2. Eliminate technically infeasible alternatives.
3. Rank technically feasible alternatives.
4. Evaluate economic, energy, and environmental impacts.
5. Select BACT.

The ~~"~~top down" reference is the process that starts by considering the most stringent form of emissions reduction technology possible, then determines if that technology is technically feasible and economically justifiable. If the technology is proven infeasible or unjustifiable, then the next less stringent level of reduction is considered. When an emission reduction technology meets the stringency, and technical and economical feasibility criteria, it is determined to be BACT.

2.2. BACT for Gas Turbine/Heat Recovery Steam Generator Systems

2.2.1. NO_X Control

NO_X can be formed in two ways in a combustion process:

1. The combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_X).

2. The oxidation of nitrogen chemically bound in the fuel (fuel-bound NO_X).

Natural gas does not contain a significant amount of fuel-bound nitrogen, so all NO_X emissions from the gas turbines and duct burners are considered to originate from thermally formed NO_X.

2.2.1.1. Identify Potentially Available Control Technologies

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.

EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was searched for natural gas-fired "large combustion turbines" that are combined cycle or cogeneration (process code 15.210). The period from 2005 to present (preparation of analysis in 2011) was originally searched, and then a further review from 1990 was done.

The lowest commonly issued NO_X emission limit for CTs of similar size listed in EPA's RBLC is 2 ppmdv (at 15 percent O_2) for 29 facilities. According to the RBLC listing, 12 of these represent LAER or California BACT (equal to federal LAER) and 17 represent BACT. Since 2003 nearly every facility has been permitted in the 2 to 6 ppmdv range. All but one combined cycle facility[4] utilizes SCR as a control technology. The only permit for less than 2.0 was issued in 2000[5] for 1.5 ppmdv, but that project was abandoned in 2003 and never built.
At least 11 combined cycle turbine projects have been permitted in the Northwest. About half have been built. These include, in order of increasing NO_X limit: Goldendale and Sumas Generation in Washington and Wanapa Energy in Oregon, which are listed at 2 ppmdv; Cob Energy, Klamath Generation, the Port Westward Plant in Oregon, Wallula Generation, Mint Farm, Satsop Combustion Turbine project (GHE I), Longview Energy in Washington and Garnet Energy in Idaho, which are all listed at 2.5 ppmdv; and Chehalis Generation and Fredrickson Power in Washington at 3 ppmdv. These facilities were all proposed to be located in attainment

[4] RBLC Number FL-0285 for Progress Electric Florida. No natural gas available, so it burns oil.
[5] RBLC Number CA-1050 for IDC Bellingham, LLC.

areas for NO_X and, therefore, represent BACT. All of the above named facilities proposed to use SCR systems for control of NO_X emissions.

The previously referenced review of EPA's RBLC, vendor inquiries, and contacts with regulatory authorities indicated several possible NO_X control technologies:

Combustion Process Controls
LNBs
XONON

Post-Combustion Controls
SCR
EMx
Selective Non-Catalytic Reduction (SNCR)

Other NO_X control technologies such as steam or water injection have been used in the past, but are not applicable to the current advanced dry low-NO_X turbine combustors unless oil fuel is to be combusted in the turbines, which is not the case for this Project.

2.2.1.2. 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.

Dry LNBs

Dry refers to not using any water or steam injection to lower flame temperature as was formerly done in older style flame diffusion styled burners. LNBs control NO_X formation in combustion turbines by staged combustion of the natural gas. LNBs 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 combustion turbine projects.

XONON

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 combustion turbine, and is eliminated from further consideration as BACT.

SCR

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

The use of SCR technology will result in ammonia emissions to the atmosphere due to unreacted ammonia leaving the SCR unit. During normal operation, low levels of the NH_3 emissions occur because ammonia is added slightly in excess of the required amount to control the NO_X present in the exhaust. These ammonia emissions are referred to as ―ammonia slip." As the catalyst degrades over time, ammonia slip will increase, ultimately requiring catalyst replacement.

EM$_X$

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 NO_X, 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 NO_X 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 have done so. In evaluating technical feasibility for large natural gas combined cycle (NGCC) power stations, additional concerns include the following:

- EMx uses a series of dampers to reroute 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 absorption 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 combustion turbines.

Although application of an EMx system to a large-scale 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-effectiveness 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 is not repeated here.

SNCR

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 ~~"a~~mmonia 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.

2.2.1.3. 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 combustion turbine, and LNBs are considered the baseline NO_X control technology.

2.2.1.4. 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. Usually it is permitted at a maximum of 5 ppm "slip," with an expected normal slip rate closer to 1 ppm.

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 deactivation of the catalyst. Because SCR has long been considered BACT for large combustion turbine units, the environmental, economic, and energy impacts have generally been deemed acceptable by EPA and Ecology.

2.2.1.5. NO_X BACT Conclusion

Based on the preceding BACT analysis, KEC proposes, and Ecology agrees, that NO_X emissions from CGT and/or duct burners shall be controlled by use of lean pre-mix dry low-NO_X turbine burners, low-NO_X duct burners, a SCR control system using ammonia injection, and good combustion practices (GCPs) as BACT. The NO_X BACT limit is determined to be control of NO_X emissions from each combustion turbine heat recovery steam generator stack to 2.0 ppmdv, 1-hour average. At maximum operating rate on a cold day, this will result in a maximum emission of 18.5 lb/hr, 1- hour average. Annual NO_X emissions would be expected to be a maximum of 75.7 tpy from the turbine and auxiliary burners if all were at normal operation, but a maximum of 102.4 tpy when start-up and shutdown emissions are included.

2.2.2. Carbon Monoxide Control

Carbon monoxide (CO) is formed as a result of incomplete combustion of fuel. CO is minimized by providing adequate oxygen availability (excess air), fuel residence time, high temperature, and turbulence in the combustion zone to ensure complete combustion. These are often called the "3 Ts" of combustion. These control factors, however, can also result in higher emission rates of NO_X. Conversely, a low-NO_X emission rate can be achieved through flame temperature control (by low-NO_X combustors) and can result in higher levels of CO emissions. A compromise is usually established where the flame temperature reduction is set to achieve the lowest NO_X emission rate possible while keeping the CO emission rates at acceptable levels.

Possible post-combustion control involves the use of catalytic oxidation, while front-end control involves controlling the combustion process to suppress CO formation. Recent LNB designs have reduced CO emissions significantly when operating near rated maximum design rates. Since these burners go through several "stages" before reaching their "low-NO_X" mode, CO emissions can be higher during start-up and shutdown periods.

2.2.2.1. Identify Control Technologies for CO

A review of the information available at the EPA's RBLC, vendor inquires, and contacts with regulatory authorities indicated that three potential CO control technologies should be considered:

Combustion Process Controls

- GCPs using well designed dry LNBs

Post-Combustion Controls

- EM_X (formerly $SCONO_X$)
- Catalytic Oxidation

A review of EPA's RBLC database from 2005 to the present and contacts with combustion turbine manufacturers indicate that the best performing and most common add-on control for CO is catalytic oxidation. However, since low CO emissions can be achieved by combustion control alone, some entries in the RBLC quote good combustion control as the BACT control option.

The lowest CO level listed in the RBLC is Kleen Energy Systems, LLC in Middlesex, Connecticut. It has a CO limit of 1.7 ppmvd (at 15 percent O_2) with duct burners. It is in a NO_X and ozone nonattainment area.

The VEP Warren project in Virginia is permitted for 1.5 ppmdv when duct burners are not burning. With duct burners, the CO limit is 2.4 ppmdv. The plant site is located about 7 km from the Shenandoah National Park (a Class I area), which places additional requirements on its emissions impacts analysis. Its emissions will also impact an ozone nonattainment area. It has not begun construction as of September 2011.

There are many NGCC facilities listed in the RBLC with 2 ppmdv as BACT. Permitted limits range up to 10 ppmdv or higher for several facilities.

Pacific Northwest permitted plants (some of which have not been built), in order of increasing short-term CO limits: Goldendale Energy, Sumas Generation, and Wallula Generation in Washington; Wanapa Energy and Cob Energy in Oregon; and Garnet Energy in Idaho at 2 ppmdv; Port Westward Plant in Oregon at 2.5 ppmdv; Chehalis Generation Facility and Satsop Combustion Turbine Project (WA) at 3.0 ppmdv; Klamath Generation (OR), at 5 ppmdv; Clark

Public Utilities (River Road), Longview Energy, and Mint Farm at 6 ppmdv. Longview Energy and Mint Farm have 2.0 ppmdv annual limits in addition. All of these facilities were proposed to be located in attainment areas for CO and, therefore, represent BACT decisions. All were permitted to use an oxidation catalyst for post-combustion control of CO.

2.2.2.2. Evaluate Technical Feasibility

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

GCPs

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 to 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. 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.

The oxidation catalyst is usually located in the HRSG, downstream of the duct burner where the temperature is within 700° 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.[6] As the exhaust gas flows through the catalyst, it causes a pressure drop which contributes to a slight loss in power output. 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.

2.2.2.3. Rank Control Technologies

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

2.2.2.4. 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 proposed 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-start-up operation.

2.2.2.5. CO BACT Conclusion

Ecology agrees with ENW that the use of GCPs in the form of modern designed dry low-NOx turbine combustors, plus an oxidation catalyst is considered CO BACT for this Project. The control system will control CO emissions from each combustion turbine heat recovery steam generator stack to 2.0 ppmdv and 11.3 lb/hr during normal operation, both on a 1-hour average. An annual CO limit per of 132 tpy per turbine (including start-up and shutdown emissions) is proposed by ENW and accepted by Ecology.

2.2.3. Volatile Organic Compounds (VOCs) Control

Incomplete combustion of natural gas fuel results in emission of some unburned hydrocarbons. VOCs are by definition organic compounds that participate in atmospheric photochemical reactions. This excludes CH_4, ethane, and several other organic compounds that have negligible photochemical reactivity. Control of VOCs is first accomplished by providing GCPs as discussed in the CO BACT discussion. Add-on control devices such as catalytic oxidation can control VOCs further.

A survey of the RBLC database indicated that burning of a clean fuel (natural gas), GCPs, and often the use of an oxidation catalyst are the VOC control technologies primarily determined to be BACT. BACT limitations for recent permits ranged from 0.7 ppmdv to about 5 ppmdv at 15 percent O_2.

[6] "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.

2.2.3.1. Identify Control Technologies

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

Combustion Process Controls

- GCPs

Post-Combustion Controls

- Oxidation Catalysts

2.2.3.2. Evaluate Technical Feasibility

GCPs

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.

Oxidation Catalyst

As discussed earlier, 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 HAPs. Oxidation catalyst systems are considered technically feasible for controlling VOC emissions from an NGCC combustion turbine.

2.2.3.3. Select Control Technology

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

2.2.3.4. VOC BACT Conclusion

Ecology agrees with ENW that BACT for VOC for the turbines is use of the CO oxidation catalyst along with GCPs. VOC emissions are limited to 1.0 ppmdv @ 15percent O_2 and 3.2 lb/hr (1-hour average) from the turbine/HRSG exhaust stack. A second limit of 47.8 tpy on a 12-month rolling total (including start-up and shutdown emissions) is also set.

2.2.4. PM BACT

PM is defined as fine solid or semi-solid materials smaller than 100 microns in size. Its regulatory definition includes only filterable particulates. PM_{10} is a subset of particulate and is defined as PM smaller than or equal to 10 microns in size. A third subset of PM is $PM_{2.5}$, which is PM smaller than or equal to 2.5 microns in size. The regulatory definitions of both PM_{10} and $PM_{2.5}$ include both filterable and condensable particulates.

Particulates from natural gas consumption are very small in size. The EPA's AP 42,[7] indicates that almost all PM emissions from gas turbines fired on natural gas are below one micrometer in equivalent diameter. In the following sections of this document, all particulates will be considered to be equal and less than $PM_{2.5}$ in size. Different PSD permitting requirements apply to the different sized based categories listed above, so this will be taken into effect, but this does not change the fact that all particulates from natural gas combustion in this project fall into the smallest size regulated PM subset, $PM_{2.5}$.

As mentioned in the first paragraph of this section, particulates from combustion are classified by a second property, whether they are solid particles in the combustion stack, or whether they form particles (condense) immediately when they cool after leaving the hot stack. The first type is called filterable because it can be collected on the surface of a mechanical filter. The particulates collected represent what is typically thought of as particulates, such as soil, unburned particles of fuel, or other solid materials. The second type of particle is called condensable, because these particles form (condense) immediately upon cooling after leaving the combustion stack. They are measured by a different test method that tries to duplicate condensation conditions as best as can be done by a test method.

Particulate emission levels from natural gas combustion are extremely low in mass as well as small in size. Testers are finding that sampling times must be extended up to four hours just to get enough weight of sample to measure by the EPA reference test methods. The particulate emission levels achieved by combusting natural gas using GCPs in modern, well-designed burners is lower than control levels achievable by particulate control technologies such as bag filters, electrostatic filters, and venturi scrubbers. Also, particulate size is so small that these controls cannot efficiently remove them. This means that particulate size and concentrations are below values for which vendors of such equipment are prepared to offer performance guarantees.

[7] AP 42, Section 1.4, Natural Gas Combustion, available on the internet from the EPA's Technology Transfer Network's CHIEF section at http://www.epa.gov/ttn/chief/efinformation.html.

The EPA has indicated that particulate control devices are not typically installed on natural gas-fired combustion turbines and that the cost of installing such control devices is prohibitive.[8] 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, and neither did the revised NSPS standard in Subpart KKKK (2006). No example of add-on type particulate control for natural gas fueled combustion turbines or similar natural gas combustion sources could be found in the EPA RBLC, or from suppliers of control equipment. The particulate control measures that were found included combustion of a low ash fuel such as natural gas and use of GCPs in well-designed combustion devices.

The small particulate size and low particulate emission level, along with the lack of any example of add-on particulate controls, and lack of vendor performance guarantees for natural gas-fired combustion units led ENW to propose that the use of natural gas fuel and GCPs be BACT for all particulates emitted from the NGCC combustion turbine. These operational controls would limit combined filterable and condensable PM_{10} and $PM_{2.5}$ emissions to 17.1 lb/hr, based on an emission factor of 0.0068 lb/MMBtu.

2.2.4.1. Particulate BACT Conclusion

Ecology agrees with ENW that BACT for PM, PM_{10}, and $PM_{2.5}$ is determined to be use of natural gas for fuel, and combustion of the fuel using GCPs in lean premix dry low-NO_X turbine burners and low-NO_X duct burners. The proposed BACT emission limits are 17.1 lb/hr filterable plus condensable particulates. An annual limit of 70.0 tpy (filterable plus condensable) is also proposed. Initial performance tests and annual testing using EPA Reference Methods 5, 201, or 201a for filterable particulate and Method 202 for condensables (both 201a and 202 were updated as of December 2010) are proposed to be done annually for the first three years of operation. If these tests all show compliance, the annual testing may be reduced to once every five calendar years. Failure of a test will require a retest and reinstate annual testing until another three consecutive years of testing show compliance.

The term ―annual" here refers to four ―QA operating quarters" (QA means Quality Assurance) as defined by the acid rain regulations in 40 CFR 72.2. If a turbine does not operate for 168 operating hours during the calendar quarter, that quarter is not counted as a QA operating quarter. This deals with the issue of these plants often being shut down, and recognizes that testing should be done after a reasonable time of operation, not just calendar time. It also recognizes that a turbine that is shut down for economic or other issues does not need to be started up just to satisfy legal testing requirements.

[8] ―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.

2.2.5. Turbine Start-Up and Shutdown BACT

2.2.5.1. Description of Start-Up and Shutdown

As discussed in Section 1.5, 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 start-ups and shutdowns, it will employ upgraded turbine physical design and operating procedures that enable the combustion turbine to start and achieve emissions compliance in a relatively short period of time compared to the previous generation of the same turbine. Essentially, the design allows a combined cycle unit to start-up almost as fast as a simple cycle unit.

This new turbine design will give the PGU much greater operating flexibility to respond to changing power generating capabilities of wind power than a traditionally designed combined cycle plant. As Table 3 showed, the PGU can start-up and begin supplying power in about 37 minutes (permitted at less than an hour though to allow for the newness of the technology) from cold, warm, and hot starts. During operation, these new turbine designs can operate at full base load, efficiently vary their output between 100 and 50 percent load, and can hold at a 50percent minimum load level with both high efficiency and acceptable emissions levels.

Table 3 also gives the turbine emissions per event. Since these start-up times are a fraction of the times previously required to heat up the steam portions of the PGU (the HRSG and steam turbine), emissions during start-up mode are much reduced from traditional combined cycle turbine designs.

Turbine start-up is defined as any operating period that is ramping up to normal operation under partial load conditions. Partial load is when the turbine burner has not staged to normal operation mode, which usually happens when reaching about 50 percent of turbine power. Start-up ends when normal temperatures have been reached in both the catalytic oxidation and SCR modules and the burner has staged to normal operating mode. Normal operating temperatures for these two catalyst systems are recommended by the catalyst system manufacturer. The draft approval limits the time allowed for start-ups in case that these proper operating temperatures and normal operation are not obtained within a reasonable time.

Shutdown starts when ramping down from normal operation (between 50 and 100 percent turbine power generation capacity), and ends when fuel flow ends.

Start-ups for this Project are classified into three types—hot, warm, and cold starts. A ―cold" start-up occurs when it has been greater than 64 hours since shutdown. ―Warm" starts are between 16 and 64 hours since shutdown. ―Hot" starts are less than 16 hours since shutdown.

An integrated microprocessor-based control system will be provided for the turbine equipment, for data acquisition, and for data analysis. This control system will be used along with carefully controlled procedures for start-up, shutdown, monitoring, and control of emissions, and for

protection of personnel and equipment. This assures that the turbine start-ups and shutdowns are carefully done to be safe, protect the equipment from damage, and minimize emissions.

2.2.5.2. Start-Up and Shutdown BACT Process

For start-up and shutdown, the five steps of the traditional ―top down" BACT process can be shortcut to two activities because start-up emissions are strongly correlated with start-up period length:

- Select a turbine with quick start capabilities.
- Operate the turbine according to the manufacturer's instructions.

Many considerations go into the choice of turbine. ENW chose the Siemens turbine because of its capability to start-up, operate at flexible load levels, and shut down a combined cycle PGU design almost as quickly as a simple cycle turbine PGU design. Combined cycle operation is much more efficient (about 56 percent) than simple cycle operation (roughly 35 percent). This makes power generation much less expensive along with reducing emissions.

The turbine manufacturer specifies start-up, operating, and shutdown procedures very carefully to protect the equipment from damage, minimize equipment stress (wear-and-tear-type damage), and for operator safety. Many of these control procedures are programmed into the computer controls of the equipment, so they are required to be followed and are outside of the operating discretion of the operators. Siemens quotes cold, warm, and hot start-up times of 37, 37, and 32 minutes respectively, and a shutdown time of 12 minutes. This is the first generation of turbines that have this quick start capability with little to no commercial operating experience, so these claimed capabilities will need to be proven. Because of this uncertainty, ENW requested that all start-ups and shutdowns be allowed a simple 1-hour time period to complete.

2.2.5.3. Start-Up and Shutdown BACT Conclusion

ENW proposes, and Ecology determines, that BACT for start-ups and shutdowns is use of a turbine with quick start capabilities such as the proposed Siemens unit, and to follow the start-up and shutdown procedures that are developed by the equipment manufacturers and documented by KEC in the equipment Start-up, Shutdown, and Malfunction Procedures Manual required by PSD permit. Start-ups of all types and shutdowns are expected to end within one hour, but since this is a new technology, Ecology anticipates that these procedures will evolve, and KEC might need to update permit conditions concerning them. Normal operating limits for NO_X, CO, and VOCs are relieved while in start-up or shutdown mode. Per start-up period limits for NO_X, CO, and VOC are listed for each type of start-up in Section V.A.3.c of the PSD permit. Emissions of VOC are estimated using emission factors supplied by Siemens. All emissions are counted toward annual emissions. Start-ups are limited to a maximum of 730 per year total of all types.

2.3. Auxiliary Boiler

One auxiliary boiler will serve the KEC power generation unit by providing steam for pre-start-up 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 have a maximum fuel input of about 36.5 MMBtu/hr. The boiler will be fueled only by natural gas.

PSD-applicable pollutant emissions from this natural gas boiler are NO_X, $PM_{10}/PM_{2.5}$, CO, and VOCs. Annual operation of the boiler will be limited to 50 percent of its design capacity, or 159,870 MMBtu per 12-month rolling total.

2.3.1. 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. The RBLC database survey results indicate that available BACT options for the pollutants emitted from auxiliary boilers include:

- Good Combustion Practices (GCPs)
- 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

2.3.2. NO_X BACT

Several combustion and post-combustion controls are commercially available for the auxiliary boiler. These controls include staged air/fuel combustion, LNBs, 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. Ecology has also developed a General Order applicable to individual installations of these small natural gas-fired boilers that is applicable in the Eastern Washington counties where Ecology has minor new source review (NSR) authority.[9] This General Order is not applicable for a boiler that is part of a PSD permit, but its requirements indicate the level of control Ecology determines is appropriate. Emission limits are set at 9 ppmdv for NO_X, and 50 ppmdv for CO, both at 3 percent O_2.

[9] General Order for Small Water Heaters and Steam Generating Boilers is available at http://www.ecy.wa.gov/programs/air/AOP_Permits/Boiler/GeneralOrders.htm.

2.3.2.1. 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
- 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

ENW 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.

2.3.2.2. Boiler NO_X BACT Decision

ENW proposes, and Ecology determines, that NO_X BACT for the auxiliary boiler is GCPs and use of ultra-low-NO_X burners capable of 9 ppm NO_X at 3 percent O_2. Because of the experiences that SWCAA has had with these new design boiler burners, SWCAA recommended, and Ecology agreed, that permit limit should be increased to 12 ppmdv to allow for more stable operation of the burners. This will produce 0.54 lb/hr of NO_X. Annual operation is limited to 50 percent of the boiler's design capacity, or 159,870 MMBtu per 12-month rolling total. A regularly scheduled tune-up program is specified in the PSD permit.

2.3.3. 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, 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.

2.3.3.1. 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)

2.3.3.2. 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. 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 tpy, 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.

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. ENW proposes that BACT for CO from the auxiliary boiler is 0.037 lb/MMBtu (approximately 50 ppmvd), 3-hour average.

2.3.3.3. Boiler CO BACT Decision

ENW proposes, and Ecology determines, that CO BACT for the auxiliary boiler is GCPs and use of ultra-low-NO_X burners. Based on recent operating experience of other boilers in their jurisdiction, SWCAA proposed, and Ecology agreed, that the CO emission level should be reduced from 50 to 30 ppmdv at 3 percent O_2. This will result in the emission of a maximum of

0.81 lb/hr of CO. A regularly scheduled testing and tune-up program is specified in the PSD permit.

2.3.4. VOC and PM BACT

2.3.4.1. 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 natural gas and GCP. Based on review of the RBLC database, add-on controls were not implemented to achieve BACT limits for these pollutants. The ranges of BACT emission limits for these pollutants are:

- VOC – 0.0044 lb/MMBtu to 0.0054 lb/MMBtu
- PM_{10} – 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.

2.3.4.2. Proposed BACT Limits and Control Option

The limited operating period for the auxiliary boiler results in relatively low annual emissions of 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 natural gas and GCP are proposed as BACT for the auxiliary boiler, and no emission rates are proposed as BACT limits for VOCs and PM_{10}. Boiler vendor information indicates that hourly average VOC and PM_{10} emission factors will be 0.004 lb/MMBtu (0.32 tpy) and 0.005 lb/MMBtu (0.62 tpy), respectively.

2.3.4.3. Auxiliary Boiler BACT Summary

ENW proposed, and Ecology agrees, that the boiler shall not combust more than 159,870 MMBtu per 12-month rolling total of natural gas fuel (50 percent of its annualized fuel use potential). BACT for NO_X emissions is 12 ppmdv NO_X at 3 percent O_2. BACT for CO is 30 ppmdv CO at 3 percent O_2. Both shall be accomplished due to the design of the boiler's LNB.

The boiler will be performance tested for NO_X and CO within 180 days of initial installation, and within every 60 months after that using appropriate EPA Methods. Periodic performance monitoring of the boiler is required. The boiler will be tested for NO_X and CO using analyzers approved by SWCAA and Ecology within every calendar year after a calendar year when EPA Method testing is done. If these tests show an exceedance of the NO_X or CO limits, KEC will either perform 60 minutes of additional monitoring to more accurately quantify CO and NO_X emissions, or initiate corrective action and retest after the corrective action, repeating this until permit limits are no longer exceeded. BACT for PM_{10}, $PM_{2.5}$, and VOC is use of natural gas fuel and GCPs. Emissions of PM_{10}, $PM_{2.5}$, and VOC will be estimated using emission factors acceptable to Ecology and SWCAA.

2.4. Cooling Tower

The 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.

2.4.1. 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.

The commercially available techniques listed to limit drift particulate 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 particulate emissions. Compared to ―conventional" drift eliminators, advanced drift eliminators reduce the particulate 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 makeup 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 makeup water), and a TDS concentration of 200 ppmw in the makeup water, which translates to a cooling water TDS concentration of 2,400 ppmw.

The substitution of a dry cooling tower is a commercially available option that has been adopted by utility-scale combined cycle plants, 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.

2.4.2. Infeasible Control Measures

One measure that has been adopted in arid, low precipitation climates or in locations that have water supply or discharge issues is the use of a dry, i.e., non-evaporative cooling system 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 particulate 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.

2.4.3. 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)

2.4.4. 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 makeup water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

2.4.5. Proposed BACT Limits and Control Option

Based on the information from the RBLC database survey, and the energy and cost factors described above, ENW's 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.

2.4.6. Cooling Tower BACT Summary

ENW proposes, and Ecology determines, that installation and operation of a drift eliminator with a maximum drift loss rate 0.0005 percent of the recirculating flow rate constitutes BACT for the cooling tower. Initial compliance will be based on submission of a copy of the drift eliminator manufacturer's certification that the drift eliminator is installed in accordance with its installation criteria.

ENW is required to submit to SWCAA and Ecology a methodology they will use to estimate particulate emissions from the cooling tower. The methodology shall be reviewed and approved by SWCAA and Ecology prior to the first operation of the cooling tower. PM_{10} (which includes

$PM_{2.5}$) emissions shall be limited to 0.88 lb/hr on a rolling annual average, estimated quarterly. A typical methodology is included in the proposed permit as:

Permittee shall calculate PM,/PM_{10}/$PM_{2.5}$ emission rate using the following calculation method

$$E = Q \times TDS \times DR$$

Where:

E = average PM/PM_{10}/$PM_{2.5}$ emission rate in lb/hr
Q = average measured water circulation rate, in MMlb/hr
TDS = total dissolved solids measured in cooling water, in ppmw
DR = manufacturer supplied drift rate (0.0005 percent)

Routine compliance will be achieved by using the calculation methodology to estimate the particulate emissions from each cooling tower. Emissions shall be reported in each quarterly emissions report.

2.5. Emergency Generator and Fire Water Pump

A nominal 800 kW backup generator powered by a nominal 1,227 brake-horsepower (bhp) 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 from the grid is not available to run the electric fire water 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 one 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 engines and stationary fire pump engines in 40 CFR Part 60 Subpart IIII (Stationary Compression Ignition Reciprocating Engine NSPS).

2.5.1. NO_X BACT

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.

Combustion Process Modifications

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.

Post-Combustion Controls

SCR: In this technology, NO_X 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.

Non-Selective Catalytic Reduction (NSCR): Similar to automobile catalytic converters, this method employs noble metal catalysts to reduce NO_X to molecular nitrogen. It operates in regimes with less than 4 percent oxygen in the exhaust, which corresponds to fuel-rich operation. The method is not feasible with lean burn internal combustion engines.

Post-combustion controls are not required by the Subpart IIII NSPS for emergency generator engines or emergency fire pump engines. The following discussions relate to whether they should be required by PSD BACT.

2.5.1.1. NO_X BACT Discussion of Performance, Energy, Environmental, and Cost Issues

Absent an emergency situation, the emergency generator and fire pump engines proposed for the KEC will only operate infrequently and for brief testing and maintenance checks (Subpart IIII limits these checks to 100 hr/yr, the PSD permit limits them to 52 hours per 12-month rolling total each). These short, transient operating periods significantly reduce the effectiveness of the post-combustion controls.

In order to meet the 1-hour NO_X impact modeling requirements, KEC agreed to use an emergency generator engine designed to meet the Tier 4 interim NO_X emission standards. This is an upgrade from the Tier II standards level required for emergency engines by the Subpart IIII NSPS.

The energy requirements of auxiliary equipment and even minor back-pressure increases reduce the available power and net energy efficiency of the engines. 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.

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 and 52 hours of annual operation per engine. Cost-effectiveness is more than $974,000 per ton, which represents a prohibitively high cost for this BACT option.

Traditional PSD permitting practices and EPA guidance (the 500 hour guidance policy) suggest that an estimate of potential hours of emergency use be made. KEC reviewed the operating history of emergency generator engines at similar power generating plants in the area, and found that their emergency engines had no hours of operation under emergency conditions. This suggests that the 52 hours of operation is representative of what actual emissions will be. Ecology previously accepted a 270 hour maximum emergency hour of operation estimate at another power generation site, so to be consistent, assigned 270 hours to the KEC plant also. Since these emergency engines would not be run unless the grid power was down, this determines that the turbine would not be running and supplying power to the grid at that time either, so total plant emissions would be much lower than permitted conditions.

2.5.2. CO and VOC BACT

As in the NO_X discussion above, 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 52 hours per year in a nonemergency mode as required by the PSD permit. These engine design requirements are the baseline for the CO and VOC engines BACT determination.

Catalytic oxidation is the only post-combustion control technology found to control CO and VOC. This 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 CO_2 and water. Typical vendor indications are that 95 percent reduction in CO and 50 percent reduction in VOC emissions should be achieved.

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 tpy, respectively, assuming a 95 percent reduction in emissions and 100 hr/yr of nonemergency 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. At 52 hours of operation per year, the cost-effectiveness would be approximately twice as expensive.

2.5.3. Emergency Generator and Fire Water Pump BACT Conclusion

KEC proposes, and Ecology agrees, that BACT for each engine includes an annual limitation of 52 hours of operation for maintenance, testing, and training. Ultra low sulfur (15 ppm S) diesel fuel is BACT for the emergency generator and fire water pump fuel. This condition will be enforced in the SWCAA NOC permit. Both engines shall meet the applicable federal new engine standards (40 CFR 60 Subpart IIII) for engines sold in 2012 or in the year of purchase, whichever is later, with the emergency generator engine meeting the Tier 4 interim NO_X standards. A nonresetable hour meter with monthly recordings of the operating hour meter reading (or automated data collection if used) shall be used to determine hours of operation.

2.6. Greenhouse Gases BACT

On May 13, 2010, EPA issued the ―Tailoring Rule" to regulate greenhouse gas emissions from stationary sources under the PSD and Title V air operating permit programs. The first step of the Tailoring Rule began on January 2, 2011, and lasted until June 30, 2011. That step is now over.

The second step of the rule started on July 1, 2011, and lasts until June 30, 2013, or until EPA issues its ―Step 3" policy concerning revising GHG threshold limits. EPA issued this policy on June 29, 2012. New construction projects that are expected to emit at least 100,000 tpy of total GHGs on a CO_2e basis, or modifications at existing facilities that are expected to increase total GHG 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 KEC facility is new and is expected to emit GHGs at a rate greater than 100,000 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 BACT must be employed to reduce GHG emissions from the proposed project.

In November 2010 EPA issued guidance for conducting BACT analyses for GHGs and updated the guidance in March 2011 (hereafter referred to as ―the March 2011 Guidance"). EPA recommended (but did not require) that permitting agencies apply to GHGs the same 5-step ―top down" process applied to determine criteria pollutant BACT.

Because BACT for GHGs is a new requirement, there are very few BACT precedents. In preparing this BACT analysis, KEC's consultant, 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).

Given the limited technological options available for end-of-stack GHG emission controls, EPA's BACT guidance emphasizes energy efficiency. In addition to reducing GHG emissions, energy efficiency also minimizes criteria and TAP emissions. The guidance recognizes that a

BACT treatment technology must be available and demonstrated in practice, not just experimental. The BACT process also cannot require an applicant to redefine the source.

Only the PGU, auxiliary boiler, diesel-powered backup generator, diesel-powered emergency fire pump, and circuit breakers are expected to emit GHGs. The following analysis considers GHG emissions from each of these proposed units.

2.6.1. Summary of Project GHG Emissions

The Tailoring Rule defines GHGs as an aggregate of: CO_2, CH_4, 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 defined 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 5 in Section 1.7 of this report previously summarized GHG emissions. It is repeated here.

Table 5. Facility-Wide Greenhouse Gas Emission Rates

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[3]	---	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
Backup 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 in each of 3 units[4]		SF_6	1% leakage/yr/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	0.00242

[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

Table 5. Facility-Wide Greenhouse Gas Emission Rates

Emission Unit	Activity	Maximum Annual Operation (hr/yr)	GHG	Emission Factor[1]	Emission Rate[2]	
					(lb/hr)	(tpy)

lb/gal emission factors were calculated using the 2.2046 lb/kg conversion factor.

[2] 100-yr 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 each individual GHG emission rate by the appropriate 100-yr time horizon 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. During permitting, the number of circuit breakers was increased to five.

[5] Worst-case expected leakage rate, based on current industry standard. The BACT process lowered the leakage rate to 0.5% per year. This change makes the project's final estimated SF_6 leakage slightly less than the original estimate shown here.

2.6.2. Power Generation Unit GHGs

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.

2.6.2.1. 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). 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, EPA acknowledged 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 would fundamentally redefine the source. In this case, use of pipeline natural gas is part of the original design of the project, and is the lowest carbon fuel available. 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.

Carbon Dioxide

CO_2 is the intended 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 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.[10] Nevertheless, per the March 2011 Guidance, CCS technology is considered an available add-on control technology for reducing CO_2 emissions from fossil fuel-fired power plants.

Methane

Like CO and VOCs, 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.

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

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

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: 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 CO_2. 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 SCR systems (i.e., those using titanium, tungsten, and vanadium-based catalysts) used to reduce emissions of NO and NO_2, as well as 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.

2.6.2.2. 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.

Carbon Dioxide

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

<u>Energy Efficiency</u>

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

CCS consists of the following 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. They are: (1) Pre-combustion systems designed to separate CO_2 and hydrogen (H_2) from produced syngas, (2) Post-combustion systems designed to separate CO_2 from flue gas, and (3) 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.

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.

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

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, the proposed PGU will employ an oxidation catalyst, which is therefore considered technically feasible.

NSCR 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 O_2). Because combustion turbines operate with high levels of excess air (i.e., approximately 15 percent O_2), NSCR is considered technically infeasible for control of N_2O from the proposed PGU.

Removal of Conventional SCR 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 SCR 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.

2.6.2.3. 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 states 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. 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. **Error! Reference source not found.** presents the thermal efficiencies of several recently-permitted power plants which featured natural gas-fired combined cycle combustion turbines.

Table 6. 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	55.7%
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)

As shown in Table 6, 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 858 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 one 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.[11] 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:

1. Carbon Capture and Sequestration—86 percent reduction in emitted GHGs on a CO_2e basis.
2. Catalytic Destruction—0.06 percent reduction in emitted GHGs on a CO_2e basis.
3. Removal of NO_X Control System (SNCR)—0.06 percent reduction in emitted GHGs on a CO_2e basis.
4. Proper Combustion/Energy Efficiency—Baseline

2.6.2.4. 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.

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

[11] 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.

cycle power plant, the cost of CO_2 avoided using CCS was $63 per ton.[12] This is almost 10 times the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2 of the KEC application (discussion not repeated in this document for brevity), 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 TAPs.

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 tpy 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 of the KEC application (as discussed above), 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 in the Project. 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

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

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.

2.6.2.5. 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 7. The facility will almost certainly not operate continuously, nor as described in Table 7, but in a manner that lies somewhere between those two extremes. KEC calculated the plant's CO_2 emission factor at 794 lb CO_2/MWhr at full operating rate, and 858 lb CO_2/MWhr when the worst case of efficiency loss factors such as start-ups, shutdowns, and low level of operation were considered.

Table 7. 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
Start-up & 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 w/duct firing at design conditions.
[2] 50% load w/duct firing at 60°F ambient temperature.
[3] Fuel use based on manufacturer information for warm start-up 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)

2.6.3. 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 its capacity on an annual basis.

2.6.3.1. 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.

Carbon Dioxide

CO_2 is the intended 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.

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.

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.

2.6.3.2. 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.

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.

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.

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. 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 NSCR Systems

NSCR systems have primarily been developed to reduce N_2O emissions from adipic and nitric acid production operations. However, 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 SCR 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 SCR 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.

2.6.3.3. 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 states 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 one 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:

1. Carbon Capture and Sequestration—86 percent reduction in emitted GHGs on a CO_2e basis.
2. Catalytic Destruction—0.06 percent reduction in emitted GHGs on a CO_2e basis.

3. Removal of NO_X Control System (SNCR)—0.06 percent reduction in emitted GHGs on a CO_2e basis.
4. Proper Combustion/Energy Efficiency—Baseline

2.6.3.4. Step 4 – Evaluate Economic, Energy, and Environmental Impacts

In the March 2011 Guidance, EPA suggests that, instead of the more traditional approach where 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.

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. DOE 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.[13] This is over 10 times the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2 of the permit application (not included in this document), 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. 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 tpy. In order to be considered cost-effective, and assuming the cost-effectiveness threshold of $7 per ton proposed in Section 1.3.2 of the

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

application, 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.

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.

2.6.3.5. Step 5 – Selection of BACT

Based on the analysis presented here, ENW proposed, and Ecology agreed, that BACT for GHGs from the natural gas-fired auxiliary boiler is energy-efficient system design, and proper combustion practices, along with limitation of the boiler's operation to 158,870 MMBtu/hr per 12-month rolling total. ENW proposed a rolling 12-month average GHG emissions limit of 190 pounds of CO_2e per thousand pounds of steam produced (lb/klb steam).

2.6.4. Reciprocating Internal Combustion Engines

A diesel-fueled backup 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 fire water pump will be available to provide pressurized water for fire protection if a fire were to occur when grid power is unavailable. Under nonemergency conditions, the engines will each operate an hour per week for maintenance and testing (i.e., 52 hours per year).

2.6.4.1. Step 1 – Identify Available Control Alternatives

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

nonemergency 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 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 previously for application to a natural gas-fired combustion turbine and a natural gas-fired boiler and were found to be not acceptable. The emergency engines must be available quickly and reliably in emergencies. Add-on controls complicate operation and potentially reduce engine readiness, so would compromise the emergency role of the engines. GHG reducing add-on technologies are therefore considered unacceptable for the emergency diesel engines.

2.6.4.2. 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.

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.

2.6.4.3. 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 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.

2.6.4.4. 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.

2.6.4.5. Step 5 – Selection of BACT

Based on the analysis presented here, ENW proposed, and Ecology agreed, 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. Also, as noted in the beginning paragraph of this section, nonemergency operation of each engine is limited to 52 hours per year for maintenance and testing. This is a very stringent GHG limitation. 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 units:

- Emergency Backup Generator – Caterpillar Standby 800 ekW 1000 kVA
- Emergency Fire Water Pump Engine – Clarke JU6H-UFADR0

2.6.5. 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 initially proposed to install three 230 kV-class circuit breakers (maximum rated voltage 245 kV) that contain about 161 lb/unit of sulfur hexafluoride (SF_6) as a dielectric medium to insulate and quench arcing when the current is interrupted. The number of breakers was later adjusted to five. 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.[14]

2.6.5.1. 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. 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 as 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

[14] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), SF_6 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.

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.

2.6.5.2. 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 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.

2.6.5.3. 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.

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

2.6.5.4. 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.

2.6.5.5. Step 5 – Selection of BACT

ENW proposes, and Ecology agrees, 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, and a leakage rate limit of 0.5 percent. 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).

3. AMBIENT AIR QUALITY IMPACTS ANALYSIS

3.1. Regulated Pollutants

The PSD permitting program requires that an ambient Air Quality Impacts Analysis (AQIA) be made for pollutants emitted in significant quantities. As shown in Section 1.4 of this Technical Support Document, NO_X, CO, VOCs, PM_{10}, and $PM_{2.5}$ are all emitted in PSD significant quantities from this Project.

An air quality analysis can include up to three parts: Significant Impact analysis, NAAQS analysis, and PSD Increment analysis. The first step in the air quality analysis is to determine if emissions from the proposed Project result in impacts greater than the modeling significance levels (MSLs). Then, for those pollutants and averaging periods that have impacts greater than the MSL, a NAAQS analysis is used to determine if the proposed Project will cause or contribute to an exceedance of a NAAQS. A PSD Increment analysis is also done for these pollutants to determine if the change in the air quality since the applicable baseline dates is greater than the Class I and Class II PSD Increment Levels. Because of the capabilities of the modeling tools, AQIA is done in two sections: an analysis of local (or near field) areas that are within 50 kilometers of the Project (done in this section), and a regional air quality impact assessment for impacts beyond 50 kilometers. The regional assessment includes impacts on Class I areas and is done in Chapter 6.

3.1.1. Model Selection and Procedures for Local Air Quality Impact Assessment

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 EPA'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. 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.

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 of 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.

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 proposed facility, collects hourly wind speed, wind direction, solar radiation, temperature, vertical differential temperature (delta-T), and lateral wind turbulence (sigma-theta, or $\sigma\theta$).[15]

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 EPA 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.

A wind rose constructed from the 1995 meteorological database shows that 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

[15] 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.

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.

3.1.2. Modeling Results for Local Air Quality Impact Assessment

To evaluate the potential ambient air pollutant concentrations, the emission rates associated with the three operating scenarios (i.e., 100 percent load with duct firing, 100 percent load, and 50 percent load) were applied in the dispersion modeling analyses.

Table 8 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). 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 8, 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. Table 9 summarizes the 1-hour average NO_2 and SO_2, and 24-hour average $PM_{2.5}$ NAAQS compliance assessment. **Error! Reference source not found.** shows that the modeling analysis predicts that none of the corresponding ambient standards would be exceeded.

Table 8. Normal Operation Project Only Maximum Predicted Criteria Pollutant Concentrations

Pollutant	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Over SIL?	Significant Monitoring Concentration ($\mu g/m^3$)	Over SMC?
CO	1-hour	47.9	2,000	Under	---	---
	8-hour	25.0	500	Under	575	Under
NO_2[1]	1-hour	112[2]	7.5	Over	---	---
	Annual	0.296	1	Under	14	Under
PM_{10}	24-hour	3.05	5	Under	10	Under
	Annual	0.171	1	Under	---	---
$PM_{2.5}$	24-hour	1.85	1.2	Over	2.3[3]	Under
	Annual	0.143	0.3	Under	---	---
SO_2	1-hour	18.2[3]	7.8[4]	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 for the 1-hour average. Annual average conversion was assumed to be 75%.
[2] The 98th percentile of the maximum predicted daily 1-hour average concentrations at each receptor.
[3] The 99th percentile of the maximum predicted daily 1-hour average concentrations at each receptor.
[4] The SIL for the 1-hour average WAAQS for SO_2 is 30 $\mu g/m^3$ (WAC 173-400-113).

Table 9. Normal Operation Ambient Standard Compliance Analysis

Pollutant	Averaging Period	Design Concentration[1]	Background Concentration[2]	Total Concentration[3]	NAAQS
NO_2	1-hour	112	73.4	185	188
$PM_{2.5}$	24-hour	1.85	19.0	20.9	35
SO_2	1-hour	18.2	138	156	196

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. For $PM_{2.5}$, the design concentration is the maximum predicted 24-hour average $PM_{2.5}$ concentration, per EPA'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 a 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 Avenue 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 through 2009 (data accessed from EPA's AQS Data Mart website.

[3] Total Concentration = Design Concentration + Background Concentration

3.2. Start-Up and Shutdown

To demonstrate that neither short-term nor annual ambient air quality standards would be exceeded as a result of starting up or shutting down the PGU, modeling simulations were developed using the short-term and annual start-up scenario emission rates described in Section 1.5. 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 start-up and shutdown. It should be noted that PGU start-up and shutdown periods are relatively brief.

The only pollutants with short-term standards that are expected to be emitted in greater quantities during start-up, when compared to normal operation at partial load, are CO, NO_X, PM_{10}, and $PM_{2.5}$. **Table 10** presents a summary of the results of the start-up 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 with 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 11 summarizes the results of those calculations, and indicates that the applicable standards will not be exceeded.

Table 10. Maximum Predicted Criteria Pollutant Concentrations Incorporating Start-up and Shutdown Operations

Pollutant	Averaging Period	Maximum Predicted Concentration (µg/m^3)	Significant Impact Level (µg/m^3)	Over SIL?	Significant Monitoring Concentration (µg/m^3)	Over SMC?
CO	1-hour	644	2,000	Under	---	---
	8-hour	41.2	500	Under	575	Under
NO_2[1]	1-hour	112	8[2]	Over	---	---
	Annual	0.318	1	Under	14	Under
PM_{10}	24-hour	3.30	5	Under	10	Under
	Annual	0.24	1	Under	---	---
$PM_{2.5}$	24-hour	2.18	1.2[3]	Over	2.3[3]	Under
	Annual	0.211	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] So SIL has been established for the federal 1-hour average NO_2 ambient standard; the threshold concentration shown is four percent of the ambient standard, and has not been proposed or promulgated as a SIL by EPA.
[3] The threshold concentrations shown are the most stringent SILs and SMC proposed by EPA for $PM_{2.5}$; these levels have not been promulgated.
[4] The SIL for the 1-hour average Washington Ambient Air Quality Standard for SO_2 is 30 µg/m^3 (WAC 173-400-113).

Table 11. Short-Term NO_2 and $PM_{2.5}$ Ambient Standard Compliance Analysis Incorporating Start-up and Shutdown Operations

Pollutant	Averaging Period	Design Concentration[1]	Background Concentration[2]	Total Concentration[3]	NAAQS
NO_2	1-hour	113	73.4	185	188
$PM_{2.5}$	24-hour	1.77	19.0	20.8	35
SO_2	1-hour	10.4	138	148	196

Note: All concentrations and standards are in µg/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 EPA's February 26, 2010, memorandum titled *Modeling Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS*.
[2] The NO2 background concentration is a 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 Avenue monitoring station from 2007 through 2009.
[3] Total Concentration = Design Concentration + Background Concentration

3.3. TAPs

Washington State requires an ambient air quality analysis of TAP emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants." The TAPs are evaluated for both acute (24-hour) and chronic (annual) effects as required by the regulation. Toxics emissions are not directly regulated under PSD regulations, but are regulated by the SWCAA in their NOC under WAC 173460. The quantities of all TAPs known to be emitted were estimated and their impacts modeled. No TAP exceeded its Acceptable Source Impact Level (ASIL).

3.3.1. Ammonia Emissions

Ammonia emissions from the Project deserve special discussion. Ammonia is a TAP defined in WAC 173-460. Unreacted ammonia is released from the SCR process because a slight excess is required to reduce NO_X emissions down to the desired levels. The excess ammonia is called "ammonia slip." Ammonia slip can be used as an indicator of SCR catalyst activity. High slip indicates poor operational control or degraded catalyst activity, resulting in higher NO_X emissions. SCR manufacturers traditionally guaranteed that this slip of unused ammonia will be less than 10.0 ppm, and most recent BACT decisions have been for 5 ppm. Recent operating experience indicates that ammonia slip may be maintained at rates consistently below 5 ppm[16] for a number of years after the initial start of the plant's operation. The air toxics modeling showed that modeled maximum ammonia impacts would be well below the ammonia ASIL found in Chapter 173-460 WAC. As with all other toxic emissions, ammonia will be regulated by SWCAA in their NOC.

3.4. Regional Ozone Analysis

40 CFR 52.21(i)(5)(i) requires any net emissions increase of 100 tpy or more of VOC or NO_X subject to PSD to perform an ambient ozone impact analysis. The KEC Project's NO_X emissions exceed 100 tpy (103.5 tpy NO_X when start-up and shutdown are included), so an ozone impact analysis on the Project's emissions was required.

The ozone impacts analysis for KEC was done by reevaluating the ozone emissions impacts estimated for the larger project previously proposed for the current site—the now withdrawn Pacific Mountain Energy Center (PMEC). The PMEC would have been a 680 MW Integrated Gasification Combined Cycle (IGCC) development. The PMEC would gasify petcoke and/or coal to create synthesis gas or ~~"~~syngas" to power two combined cycle combustion turbine electric power generating plants. It was also permitted to run full-time on natural gas.
The ozone analysis for the PMEC was done using the results of a 2006 study done to evaluate the effects that southern Washington sources might have on the Portland/Vancouver area ozone concentrations as a part of that area's ozone state implementation plan (SIP) development. The

[16] For example, PGE Coyote Springs in Morrow County, Oregon, and Hermiston Generating Project, Umatilla County, Oregon, operate at less than 4.4 ppm ammonia slip with NO_X below 4 ppm. Also see Selective Catalytic Reduction Control of NO_X Emissions, prepared by the Institute of Clean Air Companies, 1660 L Street, Suite 1100, Washington, D.C., p. 12, 1997.

ODEQ retained WSU to conduct an air quality modeling study evaluating the effects of lower Columbia River industrial emissions on ozone formation in the Portland/Vancouver region.[17] The modeling 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 (similar to the anticipated PMEC emissions). The second scenario did not include any projected future emissions from industries in the lower Columbia River.

A comparison of the ozone concentrations for the two scenarios indicated the industrial emissions had no effect on the simulated peak 8-hr ozone concentration in the Portland/Vancouver area. The results from this modeling analysis show that the anticipated PMEC emissions would not have a large impact on ozone concentrations in the Portland/Vancouver area and would not affect the area's ozone maintenance plan.

KEC proposed that the 2015 ozone precursor emission rates for the Portland/Vancouver region used in the ODEQ-WSU study overestimate the potential contribution of the KEC project. KEC also proposed that because emissions of all air pollutants, not just ozone precursors, attributable to the current KEC project are considerably less than the PMEC project, the conclusions drawn by the ODEQ-WSU ozone study are valid for the KEC project, indicating that project emission increases will not have an impact on ozone concentration in the region.

Ecology agrees with this conclusion.

4. ADDITIONAL IMPACTS ANALYSIS

4.1. 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. ENW does not expect KEC to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

[17] Summary provided in an e-mail from Svetlana Lazarev of ODEQ to Eric Hansen of Geomatrix Consultants, August 9, 2006.

4.2. 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, 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.

4.3. 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 (FLMs).

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 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.

5. CLASS I AREAS IMPACTS ANALYSIS

Federal[18] and Washington State[19] PSD regulations require that the impact of a proposed facility on federal Class I areas be analyzed. Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historic perspective and are afforded the highest level of protection under the PSD rules. They include most national parks, national wilderness areas, and national memorial parks.

The impacts analysis includes an assessment of increment consumption and impacts to Air Quality Related Values (AQRVs) in Class I areas. AQRVs include regional visibility or haze; the effects of primary and secondary pollutants on sensitive plants; the effects of pollutant deposition on soils and receiving water bodies; and other effects associated with secondary aerosol formation. The FLMs for the National Park Service (NPS), U.S. Fish and Wildlife Service (USFWS), and U.S. Forest Service (USFS) have the responsibility of ensuring AQRVs in the Class I areas are not adversely affected.

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 12, 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.

[18] 40 CFR 52.21 (p).
[19] WAC 173-400-117.

Table 12. Class I Areas and Results of Q/D Analyses			
Class I Area/Area of Interest	Distance	Q/D	
		Normal	Start-Up
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 (inc. CRGNSA)		4.0	5.1
Max Class I Area Q/D		2.6	3.3

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 EPA 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 H_2SO_4, in tpy (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 12, 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[20] 24-hour average hourly emission rates for each pollutant of interest (NO_X, SO_2, PM_{10}, and H_2SO_4) were converted to tpy by multiplying by

[20] 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.

8,760 hr/yr and dividing by 2,000 lb/ton, and summed. Because the frequency of start-ups 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 start-ups for each pollutant (i.e., regardless of whether the worst-case scenario for a given pollutant conflicts with that of another). Table 12 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. 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 earlier in Table 10, NO_X (1 hour), $PM_{2.5}$ (24 hour), and SO_2 (1 hour) exceed the PSD SERs. 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 680 MW Integrated Gasification Combined Cycle (IGCC) power generation facility to be called the PMEC. Table 13 and Table 14 summarize the emission units and associated normal operation 24-hour average emission rates for PMEC and KEC, respectively.

Table 15 compares the two projects, dividing KEC emission rates by PMEC emission rates for each emission unit type, as well as for the entire facility. Table 16, Table 17, and Table 18 provide the analogous information (i.e., KEC, PMEC, and KEC divided by PMEC) for operations affected by start-up, and Table 19, Table 20, and Table 21 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 (346 MW for KEC versus 680 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 KEC versus two for PMEC). Nevertheless, the exhaust release characteristics for emission unit categories that the two projects do have in common are similar.

Table 13. 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

Table 13. 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
Flare	0.01	0.14	0.02	0.00	0.00	0.00	0.01	0.00	0.00
Emergency diesel generator	0.05	1.17	0.04	0.00	0.00	0.03	0.00	0.00	0.00
Emergency 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

Table 14. 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 backup 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 15. 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 auxiliary boiler/PMEC auxiliary boiler	87%	12%	43%	87%	87%	43%	13%	---	---
KEC emergency generator/ PMEC emergency generator	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%

Table 16. PMEC 24-Hour Average Start-Up 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

Table 16. PMEC 24-Hour Average Start-Up 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
Flare	18.46	58.47	6.68	1.90	1.38	1.67	3.11	0.00	0.00
Emergency diesel generator	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emergency 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

Table 17. KEC 24-Hour Average Start-up 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 backup 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 18. Comparison of KEC and PMEC 24-Hour Average Start-Up 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 auxiliary boiler/PMEC auxiliary boiler	87%	12%	43%	87%	87%	43%	13%	---	---
KEC emergency generator/ PMEC emergency generator	---	---	---	---	---	---	---	---	---
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%

Table 19. 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
Emergency diesel generator	0.01	0.32	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Emergency 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

Table 20. 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 backup 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 21. 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 auxiliary boiler/PMEC auxiliary boiler	59%	23%	86%	59%	59%	86%	124%	---	---
KEC emergency generator/ PMEC emergency generator	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%

Although scaling predicted impacts using emission rate ratios is not a robust method for predicting impacts, it made sense that, because of the similar location and emission unit characteristics, the results of the Class I analysis developed for PMEC 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 22) were scaled to obtain estimated maximum Class I area concentrations attributable to KEC (Table 23). 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 estimated impacts attributable to KEC were predicted to exceed the SILs proposed by EPA or those recommended by the FLMs.

Table 22. PMEC Predicted Class I Area and Area of Interest Criteria Pollutant Concentrations

Class I Area/ Area of Interest	Normal Short-Term/Worst-Case Annual Operation						Start-Up		
	NO_2	PM_{10}		SO_2			PM_{10}	SO_2	
	Annual	24-Hr	Annual	3-Hr	24-Hr	Annual	24-Hr	3-Hr	24-Hr
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	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.	0.0027	0.070	0.0060	0.2570	0.0389	0.0022	0.0976	0.2916	0.0437
EPA Proposed SIL	0.1	0.3	0.2	1	0.2	0.1	0.3	1	0.2
FLM Recommended SIL	0.03	0.27	0.08	0.48	0.07	0.03	0.27	0.48	0.07
Class I Area PSD Increment	2.5	8	4	25	5	2	8	25	5

Table 23. KEC Predicted Class I Area and Area of Interest Criteria Pollutant Concentrations

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

6. CONCLUSION

The Project will have no significant adverse impact on air quality. The Washington State Department of Ecology's Air Quality Program finds that the applicant, Energy Northwest, has satisfied all requirements for a Notice of Construction/Prevention of Significant Deterioration approval for the Kalama Energy Center, LLC.

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ACRONYMS AND ABBREVIATIONS

°F	degrees Fahrenheit
$\mu g/m^3$	micrograms per cubic meter
AQIA	air quality impacts analysis
AQRV	air quality related values
ASIL	acceptable source impact level
BACT	Best Available Control Technology
CCS	carbon capture and sequestration or storage
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FLAG	Federal Land Managers' Air Quality Relative Values Workgroup
FLMs	Federal Land Managers
GCPs	Good Combustion Practices
GHG	greenhouse gas
GWP	global warming potential
H_2SO_4	sulfuric acid mist
HAPs	hazardous air pollutants
hr/yr	hour(s) per year
kV	kilovolt
kW	kilowatt
MACT	Maximum Achievable Control Technology
MSLs	modeling significance levels
MW	megawatts
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NOC	Notice of Construction

NO_X	nitrogen oxides
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	new source review
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers in diameter
$PM_{2.5}$	particulate matter less than 2.5 micrometers in diameter
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million by volume dry
PSD	Prevention of Significant Deterioration
PTE	potential to emit
Q/D	tons per kilometer
RBLC	RACT/BACT/LAER Clearinghouse
S	total sulfur
SCR	selective catalytic reduction
SNCR	selective non-catalytic reduction
SERs	significant emission rate(s)
SF_6	sulfur hexafluoride
SIL	significant impact level
SWCAA	Southwest Clean Air Agency
TAPs	toxic air pollutant(s)
tpy	tons per year
ULSD	ultra-low sulfur diesel
USFS	United States Forest Service
USFWS	United States Fish and Wildlife Service
WAC	Washington Administrative Code