Technical Support Document for
Prevention of Significant Deterioration and
Notice of Construction Permit

for

Grays Harbor Energy Center Units 3 and 4 Project
No. EFSEC/2009-02
Grays Harbor County, Washington

October 13, 2010

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1. EXECUTIVE SUMMARY

Grays Harbor Energy II, LLC is proposing to add two combustion turbine generators (Units 3 and 4) and a single steam generator to the existing Grays Harbor Energy Center. This will increase the maximum electrical generation capacity by approximately 650 MW, with a total project nominal average capacity of approximately 1,300 MW.

The Energy Facility Site Evaluation Council (EFSEC) has reviewed the Prevention of Significant Deterioration (PSD)/Notice of Construction (NOC) application and found that the applicant has satisfied all requirements for approval of the application. This technical support document explains the Project and the proposed air emissions permit.

2. INTRODUCTION

2.1. The Permitting Process

2.1.1. The Prevention of Significant Deterioration Process

The PSD procedure is established in Title 40, Code of Federal Regulations (CFR), Part 52.21. Federal 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 serious adverse environmental impact from emissions into the atmosphere by a proposed new 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 environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

EFSEC is the PSD permitting authority for new thermal energy facilities with a net electrical output greater than 350 Megawatts (MW), sited in the state of Washington, per Chapter 80.50 of the Revised Code of Washington (RCW) and Chapters 463-60 and 463-78 of the Washington Administrative Code (WAC).

2.1.2. The Notice of Construction Process

The procedure for issuing a NOC permit is established in Chapter 70.94 RCW, Chapter 173-400 WAC and Chapter 173-460 WAC.

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

WAC 173-460-040 (new source review) supplements the requirements contained in Chapter 173-400 WAC by adding additional requirements for sources of toxic air pollutants.

EFSEC is the NOC permitting authority for thermal energy facilities greater than 350 MW sited in the state of Washington as defined in Chapter 463-60 WAC and Chapter 80.50 RCW.

2.1.3. Federal Regulations Summary

This 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 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

2.1.4. State Regulation Summary

This 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 regulations will be addressed:

Air emissions permits and authorizations	Chapter 463-60-536 WAC
General Regulations for Air Pollution Sources	Chapter 173-400 WAC
Operating Permit Regulations	Chapter 173-401 WAC
Acid Rain Regulations	Chapter 173-406 WAC
Controls For New Sources of Toxic Air Pollutants	Chapter 173-460 WAC

2.2. The Project

2.2.1. The Site

The site is located south of the Chehalis River near the town of Elma (Figure 1). The 1,600-acre Satsop Development Park surrounds the site on all four sides. The site is located approximately 0.5 mile southwest of the river. Fuller Creek is approximately 0.5 mile to the east, and Workman Creek is located approximately two miles to the east.

In 1994, Energy Northwest submitted an application to build the Satsop Combustion Turbine Project on this 22-acre site. The 22-acre site was part of the much larger site approved for construction and operation of a nuclear facility in 1976. That facility was partially built, but not finished. In 1996, EFSEC permitted a natural gas-fired combustion turbine facility to be constructed on the site. The project later changed ownership and was redesigned so that the original facility, now known as the Grays Harbor Energy Center, could be built on only approximately 12 acres of the site.

Construction of the Grays Harbor Energy Center (Units 1 and 2) was completed in the second quarter of 2008 and commercial operation began April 25, 2008. Units 1 and 2 are owned and operated by Grays Harbor Energy, LLC.

Units 3 and 4 will be constructed entirely within the boundaries of the approximately 22-acre Satsop Combustion Turbine (Grays Harbor Energy Center) Project site. Proposed Units 3 and 4 will be owned and operated by Grays Harbor Energy II, LLC.

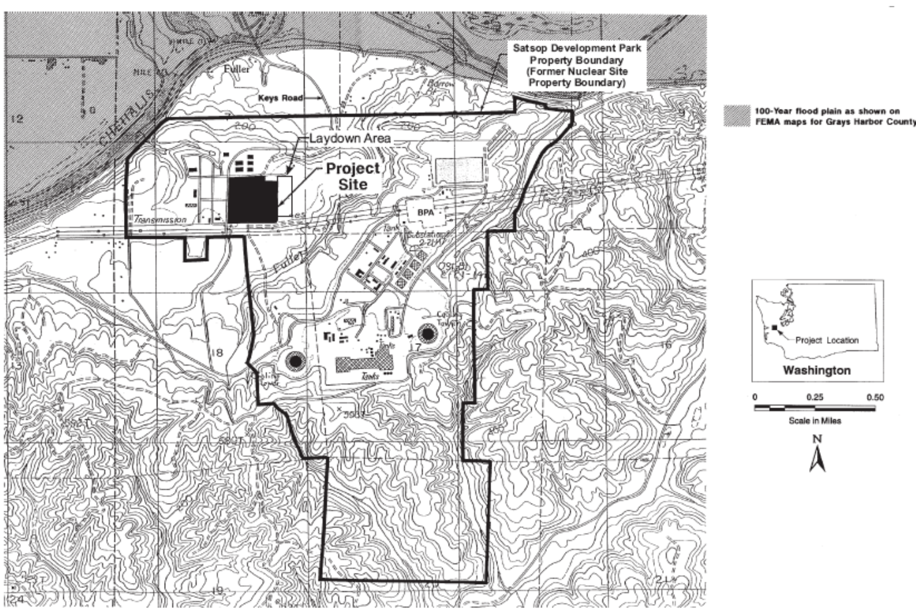

Figure 1. Project Location

2.2.2. The Grays Harbor Energy Center Units 3 and 4 Project

Grays Harbor Energy II, LLC is proposing to add two combustion turbine generators (Units 3 and 4) and a single steam turbine-driven generator to the existing Grays Harbor Energy Center.

This will increase the maximum electrical generation capacity by approximately 650 MW, with a total project nominal average capacity of approximately 1,300 MW.

The fuel will be natural gas only, and will be supplied by an existing pipeline that was constructed as part of the initial site development.

The Project is made up of the following components:

- Two (2) combustion turbine generators (CTG)
- Two (2) heat recovery steam generators (HRSG)
- One (1) steam turbine generator (STG)
- One (1) auxiliary boiler
- Fuel supply
- Cooling system
- Fire protection
- Emergency generator

Combustion Turbine Generator

The Project includes installation of two GE 7FA turbine generators, each with a gross capacity of approximately 175 MW. The GE 7FA is a frame type industrial combustion gas turbine and will have dry low NO_X burners.

Heat Recovery Steam Generator

The high temperature exhaust produced by the combustion turbines flows directly to an 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. The Selective Catalytic Reduction (SCR) control equipment for removal of 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 300 MW.

Auxiliary Boiler

An approximately 30 MMBtu/hr auxiliary natural gas-fired boiler will be installed with a low-NO_X burner to produce steam at approximately 25,000 pounds per hour 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 Grays Harbor Energy Center will continue to be natural gas only. The natural gas supply will connect to the metering station on site that has been constructed as part of the Grays Harbor Energy Center.

Cooling System

The proposed cooling system consists of two major components: (1) a circulating water system that will carry cooled water from the cooling tower through the steam turbine condenser and back to the cooling tower, and (2) an auxiliary cooling water system that will be tied into the circulating water system to provide water for cooling major equipment within the combined cycle facility. The evaporative cooling tower will consist of a 10-cell structure approximately 276 feet long, 114 feet wide, and 52 feet high. A high efficiency drift eliminator with a maximum loss of only 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 system for Units 3 and 4 will be similar to the system already installed at the Grays Harbor Energy Center for Units 1 and 2. The firewater pump will be powered by a diesel engine of about 275 horsepower, and will burn diesel fuel with less than 15 ppm sulfur content.

Emergency Generator

An emergency generator of about 400 kw will be installed to provide emergency power when power from the grid is not available. It will have a 600hp diesel engine, and will burn the same ultra low sulfur diesel fuel as the fire pump engine.

2.3. New Source Performance Standards (NSPS)

40 CFR 60 Subpart KKKK is applicable to the nitrogen oxides (NO_X) and sulfur oxides (SO_2) emissions from the combustion turbines and duct burners. This NSPS limits NO_X emissions from the proposed Project's turbines and duct burners to 15 parts per million dry volume (ppmdv) or 54 nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt hour (lb/MWh)). SO_2 emissions are not to be in excess of 110 ng/J (0.90 lb/MWh). As an alternative, sulfur in fuel may be monitored. Sulfur content is not to exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) of heat input. This is the equivalent of a natural gas tariff of 20 grains sulfur per 100 cubic feet of natural gas. Test methods for NO_X and sulfur emissions are specified. It requires 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 United States Environmental Protection Agency's (EPA's) Region 10. Note that application of the "top down" Best Available Control Technology (BACT) process creates

NO_X and sulfur emission limits that are lower than these NSPS maximum limits. There are no NSPS requirements for carbon monoxide (CO), particulates (PM), particulates less than 10 microns in diameter (PM_{10}), particulates less than 2.5 microns in diameter ($PM_{2.5}$), or volatile organic compounds (VOCs) in Subpart KKKK.

40 CFR 60 Subpart Dc applies to steam generating units that commence construction, modification, or reconstruction after June 9, 1989, and have a heat input capacity from fuels combusted in the steam generating unit of less than 100 MMBtu/hr and greater than or equal to 10 MMBtu/hr. Subpart Dc would apply to the auxiliary boiler because it would be rated at 29.3 MMBtu/hr. Subpart Dc does not establish any emission limits for boilers fired solely with natural gas.

40 CFR 60 Subpart IIII applies to the emergency firewater pump engine and emergency generator engine proposed for Units 3 and 4. 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. Subpart IIII limits emergency engines such as the emergency generator and firewater pump engine to 100 hours per year of non-emergency operation (e.g., maintenance and testing).

2.4. Project Emissions and PSD Applicability

The Grays Harbor Energy Units 3 and 4 Project (Project) is permitted as a major source.[1] Emission of a regulated pollutant[2] at levels considered significant[3] by the federal PSD regulations require permitting under the federal PSD program. As Table 1 shows, NO_X, CO, VOC, PM_{10}, SO_2, and sulfuric acid mist (H_2SO_4) are all emitted in PSD significant quantities. All other PSD regulated pollutants (such as 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 the NOC permit.

After the application of emission controls representing BACT or to protect ambient air quality, the Project is proposed to have annual emissions as shown in Table 1. The turbines will have short-term emissions as shown in Table 2.

[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. In Washington State, EFSEC 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.

Table 1. Project Annual PSD/NOC Pollutant Emissions (tons per year)

	NO_X	CO	SO_2	H_2SO_4	PM_{10}	$PM_{2.5}$	VOC	NH_3
	Annual Emissions With Continuous CT Operation (8,760 hours per year)							
Combustion Turbines[a] w/ Duct Firing	175	107	62.8	32.1	166	41.6	30.5	162
Combustion Turbines[a] @ 100% Load	139	84.6	48.5		166	41.6	24.2	
Combustion Turbines[a] @ 60% Load	98.8	60.1	34.5		166	41.6	51.5	
Maximum Combustion Turbines[a] Scenario	175	107	62.8	32.1	166	41.6	51.5	162
Auxiliary Boiler[b]	0.40	1.4	0.21		0.18	0.046	0.15	
Emergency Generator[c]	0.051	0.045	0.000095	-	0.0026	0.0021	0.051	
Firewater Pump Engine[c]	0.018	0.015	0.000043	-	0.0024	0.0020	0.018	
Cooling Tower[d]	--	--	--	-	3.5	3.5	--	
Total Emissions	**176**[e]	108	**63.0**	**32.1**	**170**	**45.1**	51.7	**162**
	Annual Emissions With Worst-Case Start-Up and/or Shutdown Schedule							
Combustion Turbines[a]	166	450	43.7		116	29.0	52.9	
Auxiliary Boiler[b]	0.40	1.4	0.21		0.18	0.046	0.15	
Emergency Generator[c]	0.051	0.045	0.000095	-	0.0026	0.0021	0.051	
Firewater Pump Engine[c]	0.018	0.015	0.000043	-	0.0024	0.0020	0.018	
Cooling Tower[d]	--	--	--	-	3.5	3.5	--	
Total Emissions	166	**451**	43.9	-	120	32.5	**53.1**	
	PTE Summary and Comparison to PSD Significant Emissions Rate							
Potential to Emit (PTE)	176	451	63.0	32.1	170	45.1	53.1	162
PSD Significant Emissions Rate (annual)[f]	40	100	40	7	15	10	40	N/A

Annual emissions in tons.
a. Combined emission rates for both Units 3 and 4 combustion turbine units.
b. 2,500 hours of operation per year.
c. Maximum of 26 hours of operation for maintenance and testing.
d. Total for 10 cooling tower cells.

e. Bolded numbers are the Project's potential to emit. Most are from normal operation with turbines running at 8,760 hours per year, but CO and VOC are higher when turbine start-ups and shutdowns are considered.
f. No other PSD regulated pollutants are emitted at more than trace quantities.

Table 2. Maximum Short-Term Normal Operation PSD/NOC Pollutant Emissions (lb/hr)

Operating Mode	24-hr NO_X	1-hr CO	8-hr CO	1-hr SO_2	3-hr SO_2	24-hr SO_2	24-hr PM_{10}	24-hr $PM_{2.5}$	1-hr VOC	1-hr NH_3
Combustion Turbines[a]	40.0	24.4	24.4	28.3	28.3	26.1	38.0	9.50	6.96	37.0
Auxiliary Boiler	0.32	1.1	1.1	0.17	0.17	0.16	0.15	0.037	0.12	-
Emergency Generator[b]	0.16	3.5	0.43	0.0073	0.0024	0.00030	0.0082	0.0082	3.9	-
Firewater Pump[b]	0.057	1.2	0.15	0.0033	0.0011	0.00014	0.0075	0.0075	1.4	-
Cooling Tower	--	--	--	--	--	--	0.8	0.8	--	-
Total	40.6	30.1	26.0	28.5	28.5	26.3	39.0	10.3	17.2	37.0

All emission rates are in pounds per hour averaged over the period indicated.
a. Worst-case combined emission rates for both Units 3 and 4.
b. Maximum of 1 hour of operation per day.

Emissions are subject to both short-term and long-term limits. Short-term limits, such as hourly, 3-hour, or 24-hour averaging periods are usually larger in order to allow for fluctuations in the emissions of the measured pollutant. Long-term limits, such as monthly or annual, reflect the more stable average emission rate over that longer period. The annual averages include emissions from events such as start-up and shutdown.

2.5. Start-Up and Shutdown Emissions

Emission rates of some pollutants are higher during start-up than during normal operations because combustion is not yet optimized and/or because control equipment is not functional under all operating conditions. Some pollutant emission rates can be lower because fuel consumption is lower during start-up and shutdown than at maximum operating rates.

Combustion turbines emit more carbon monoxide during start-up because combustion is optimized for a hot turbine engine and higher loads (usually 60 percent load or greater), and the oxidation catalyst is not as effective at low exhaust gas temperatures. Similarly, combustion turbine NO_X emission rates are also higher during start-up because the low NO_X burner has not staged into its Mode 6 operating stage (the low NO_X mode of operation during normal operation), the SCR system is not effective at low exhaust gas temperatures, and because ammonia is generally not introduced until temperatures that promote the desired reactions are achieved. Shutdown is usually fairly quick, resulting in few excess emissions.

As summarized in Table 1, GHE carefully analyzed estimated emissions for this Project, and determined that annual emissions of CO and VOC from the turbines are best estimated for modeling and impacts analysis purposes at rates higher than would be represented by multiplying the shorter term emission factors (such as hourly, 3-hour, or daily) factors by 8,760 hours or other appropriate annualizing factor. The annual emission rates calculated by GHE are based on careful estimates of operating hours under maximum and reduced load conditions, the effect of start-up and shutdown emissions, and the number of non-operating hours.

GHE initially analyzed the turbine startup/shutdown emissions using data supplied by General Electric (GE), the turbine manufacturer. After analysis of six different scenarios of start-up and shutdown, GHE determined that the maximum annual emissions (other than at normal maximum operation for 8,760 hours) were almost all generated by the maximum emission rates resulting from hot starts followed by 16 hours of operation, then a shutdown followed immediately by another hot start-up, and repeating that cycle for an entire year. The exception is for CO, where the scenario in which the cycle begins with a warm start and ends with 10 hours of downtime is slightly higher than the hot start scenario with no downtime. Table 3 shows estimated emissions during three types of start-ups (hot, warm, and cold), and during transition to shutdown. This data, when entered into the various operating scenarios, generated the annual emissions estimates.

Table 3. Combustion Turbine Total Startup/Shutdown Emissions (per GE)

Scenario[a]	Time[b] (min)	NO_X	CO	SO_2[c] (1- and 3-hr)	SO_2[c] (24-hr)	SO_2[c] (annual)	PM	VOC
Cold Start	241	520	1,300	22.0	20.3	11.0	50	80
Warm Start	124	275	1,900	13.2	12.2	6.6	30	120
Hot Start	83	175	800	10.1	9.3	5.1	20	60
Shutdown	30	100	650	3.8	3.5	1.9	8	40

Emissions in pounds per event for the Units 3 and 4 combustion turbines.

a. Cold start – start-up following a 72-hour or greater period of non-operation. Hot start – start-up following 8 hours or less of non-operation. Wart start – start-up following between 8 and 72 hours of non-operation.

b. Time for both turbines to reach 60% load for start-up, and for both turbines to go from 60% load to no operation for shutdown.

c. SO_2 start-up/shutdown emissions are based on the following assumed fractions of maximum full load operation emissions: cold start – 50%, wart start – 58.5%, hot start – 67%, shutdown – 70%.

GHE further analyzed historical operational records of its Units 1 and 2, and submitted the proposal that turbine start-ups be classified into only two types based on a 48-hour shutdown period. A cold start is longer than 48 hours of downtime, and a warm start is less than 48 hours. A cold start-up can last up to five hours, and a warm start-up up to three hours. Emissions were estimated for a start-up period (either length) based on Table 3 and an additional 25 percent margin. The emissions are to be a maximum of 875 pounds NO_X, 500 pounds of CO, and 150 pounds of VOC per start-up period. To allow startup of all four turbines (two existing plus two new) at the same time, their impact on Class I area visibility was also modeled. See Section 6.4, Table 22 for details.

NO_X and CO will be measured by CEM monitors, and VOC is estimated using an emission factor. All start-up and shutdown emissions will be counted toward annual emissions.

As discussed several times earlier, emissions during start-up and shutdown periods are different then during normal operation. Also, some pollutant permit limits are larger for short-term emissions to account for variability, but lower for longer averaging periods, such as annual. Pollutant impacts have been modeled at these different short- and long-term averaging rates. To ensure compliance with the modeling, and for other reasons, the annual emissions limits in Table 4 are included in either the PSD or the NOC portion of these permits.

Table 4. Annual Emission Limits on Individual Equipment

Unit	NO_X	CO	PM_{10}	SO_2	VOC
Each CTG/HRSG, tons/yr	87.5	225	83.0	31.4	25.75
Cooling Tower, tons/yr	N/A[1]	N/A[1]	3.5	N/A[1]	N/A[1]

1. N/A means "not applicable." The cooling tower only has particulate emissions.

2.6. Toxic Emissions

Most toxic air pollutants that would be emitted by the Project are a subset of the criteria pollutant emissions listed in Table 1. This includes toxic air pollutants listed as federal Hazardous Air Pollutants (HAPS) and those listed as Washington State Toxic Air Pollutants (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_{10}. Nitrogen oxide (NO, a state TAP but not a federal HAP under the version of 173-460 applicable for this application) is a portion of the NO_X potential emissions estimate.

Toxic air pollutant emissions are estimated and their impacts are evaluated as part of the ambient air quality analysis in Section 4 of this Technical Support Document. Toxic emissions are regulated in the NOC portion of this EFSEC permit according to EFSEC's adoption of the Washington State regulation 173-460 WAC as of March 1, 2005.

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. At the proposed maximum "slip" of 5.0 ppmdv, total ammonia emissions to the atmosphere would be 162 tons per year. Ammonia and other toxic air pollutant emissions from the proposed Project that have modeled impacts are discussed in Section 4.2.

3. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

3.1. 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 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.

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

3.2.1. Nitrogen Oxides Control

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

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

3.2.1.1. Review of Previous BACT Determinations for NO_X

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 2009) was originally searched, and then a 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% 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 utilizes SCR as a control technology. The only permit for less than 2.0 was issued in 2000[4] for 1.5 ppmdv, but that project was abandoned in 2003 and never built.

At least 11 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 areas for NO_X and, therefore, represent BACT. All of the above named facilities proposed to use Selective Catalytic Reduction (SCR) catalyst systems for control of NO_X emissions.

Potentially Available Control Technologies

The formation of NO_X from the proposed CTs is minimized by the use of dry low NO_X combustors. These combustors control NO_X to as low as 9 ppmvd (0.06 lb/MMBtu) for the GE 7FA turbine under full load operating conditions and for loads down to 60 percent during natural gas firing. They can also be tuned several parts per million NO_X higher for optimum efficiency, especially if emissions go to a NO_X control device such as SCR. The HRSG is proposed to be equipped with low NO_X duct burners with a NO_X emission rate of about 0.08 lb/mmBtu. To achieve lower levels of NO_X, add-on controls are required.

A review of the information available at the EPA's RBLC, vendor inquiries, and contacts with regulatory authorities indicated that three potential additional NO_X control technologies should be considered: SCR, EM_X (formerly $SCONO_X^{TM}$), and XONON. All three claim to reduce NO_X to 2 ppmdv, so they are considered equally stringent for this Project. 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. Selective Non Catalytic Reduction (SNCR) has been used on boilers, but not on turbines. It is discussed below.

3.2.1.2. XONON

XONON is a catalytic process that reduces NO_X emissions within the turbine combustion zone by lowering the combustion temperature and; hence the NO_X formation. Each XONON equipped turbine model requires a unique burner design. The first XONON burner was commercially demonstrated on a Kawasaki 1.5 MW turbine. The owner of the process, Catalytica Energy Systems, originally published news reports that XONON equipped combustors were being developed for use in several 5 to 10 MW sized turbines by other turbine manufacturers, but these efforts did not become commercial. Because XONON has not yet been

[4] RBLC Number CA-1050 for IDC Bellingham, LLC

developed for the larger GE turbines, EFSEC determines that it is not technically feasible for this Project and is eliminated from further consideration as BACT.

3.2.1.3. EM_X (formerly $SCONO_X$™)

The EM_X (formerly $SCONO_X$) system is an add-on control device that reduces emissions of multiple pollutants. EM_X control technology is provided by EmeraChem, LLC (formerly Goal Line Environmental Technologies). EM_X simultaneously oxidizes CO to CO_2, NO to NO_2, and then absorbs NO_2 onto the surface of a catalyst using a potassium carbonate absorber coating. VOCs are also removed by the catalyst system. The system does not use NH_3, and operates most effectively at temperatures ranging from 300°F to 700°F. Operation of EM_X requires natural gas, water, steam, electricity, and ambient air. Steam and reformed natural gas are used periodically to regenerate the catalyst bed and are an integral part of the process.

Because of historical issues, the terms EM_X and $SCONO_X$ are used interchangeably for this discussion.

There are currently several EM_X units in commercial installations worldwide. All are applied to emission units that are much smaller than those proposed for the Project. The original application of EM_X 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 EM_X system since December 1996. That system has undergone many changes over the years. The second commissioning of a EM_X 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 EM_X demonstration period. Three other units were installed in recent years, two on 13 MW Solar Titan CTs at the University of California, San Diego, and one on an 8 MW Allison combustion turbine at Los Angeles International airport.

The EPA's Environmental Appeals Board (EAB) and the California Energy Commission (CEC), on May 30, 2001, issued simultaneous rulings on another project refusing to overturn a BACT decision by the Shasta County Department of Resource Management Air Quality Management District that the $SCONO_X$ technology is not technically feasible for turbines of the size being considered for the proposed Project. The District's BACT decision said that there are several operational requirements associated with the $SCONO_X$ technology that make it impractical as an emission control technology for 'F' Class turbines. It stated that not all routine operating conditions were covered in the $SCONO_X$ technology guarantee and that the guarantee would be voided if liquid water came into contact with the catalyst. SCR was the alternative BACT technology that was selected. For further information, see the "Three Mountain Power, LLC CEC Decision" and "EPA PSD Appeal No. 01-05 (May 30, 2001)."

There is no current working experience of EM_X on large combustion turbine units such as those proposed for this Project. EM_X 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, which they have done.

Although application of an EM_X system to a large combustion turbine has not be demonstrated in practice, it probably can be considered technically feasible for such an application. However, the high capital and operating costs of the EM_X system make it not cost-effective when compared to an SCR system capable of achieving similar emission rates. EFSEC previously obtained (in 2006) a cost quote directly from EmeraChem to install $SCONO_X$ on another EFSEC project (BP Cogeneration Project at the BP refinery in Blaine, Washington). This project was very similar to GHE, so it is considered to be representative. EmeraChem offered two price options:

1. The complete system could be purchased, which includes the mechanical equipment and the catalyst. The economic analysis concluded that the annualized cost to remove 309 tons per year of NO_X from the GE turbines (about 90 percent removal efficiency) is $22,900.

2. The mechanical purchase/lease option allows the customer to buy the mechanical equipment and lease the catalyst. The annualized cost was estimated at $15,500 per ton of NO_X removed.

Since $SCONO_X$ can remove NO_X, CO, and VOC simultaneously, the cost per total pollutant removed using $SCONO_X$ was determined. The economic analysis concluded that the annualized cost was $13,000 per ton of pollutant (NO_X + CO + VOC) removed for the purchase option, and $8,800 for the lease option.

Because SCR is well proven to provide emission reductions equal to the EM_X claims, because of the technical uncertainties surrounding EM_X, and because EM_X ($SCONO_X$'s) cost per ton of NO_X removal is greater than that of SCR ($5,900 per ton of NO_X removed as determined in the BP cost evaluation), EFSEC concludes that EM_X is not to be considered BACT for the control of turbine NO_X emissions for the Project.

3.2.1.4. Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) is a post-combustion NO_X control technology in which a reagent (anhydrous NH_3 or urea) is injected into the exhaust gases to react chemically with NO_X, forming elemental nitrogen and water without the use of a catalyst. The success of this process in reducing NO_X emissions is highly dependent on the ability to achieve uniform mixing of the reagent into the flue gas 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. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 second. The consequences of operating outside the optimum temperature range are severe. Above the upper-end of the temperature range, the reagent will be converted to NO_X. Below the lower-end of the temperature range, the reagent will not react with the NO_X and the NH_3 discharge from the stack (known as "ammonia slip") will be very high. Under good conditions, NO_X conversion rates are typically between 25 and 60 percent.

This technology is usually used in heaters or boilers upstream of any HRSG or heat recovery unit. SNCR has never been used in CT 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 allow the SNCR flue gas reactions.

Because of the incompatibility of the exhaust temperature with the SNCR operating regime, and because SNCR has not been applied to a combustion turbine application, EFSEC determines that this technology is technically infeasible and is removed from further consideration as BACT.

3.2.1.5. Selective Catalytic Reduction

SCR is a control technique that has been widely used since the 1980s in a large number of power generation applications, mainly for large gas turbine combined cycle power plants that include heat recovery steam generators. In an SCR system, ammonia is injected into the exhaust gas where it reacts with NO_X at a catalyst bed. The catalyst lowers the activation energy of the chemical reactions that take place in order to reduce ammonia and NO_X to nitrogen gas and water. SCR can provide 80 to 90 percent NO_X control.

The SCR catalyst reactor is typically of fixed bed design. In this reactor design, the catalyst bed is oriented perpendicular to the flue gas flow. In this Project, where there is an HRSG used for heat recovery, the SCR unit would likely be installed between the superheater and the high-pressure evaporator coils of the HRSG. The catalyst typically would be a vanadium titanium catalyst system, which has an operating temperature range of about 600 to 800°F. Alternative catalyst systems can extend this temperature operating range up to about 200°F in either direction.

Installation of a catalyst bed also causes a pressure drop of approximately four inches of water, which contributes to a loss in power output from the facility.

Sulfur content of the fuel is an additional concern for systems that employ SCR. Catalyst systems promote oxidation of sulfur dioxide to sulfur trioxide (SO_3), which combines with water to form sulfuric acid or reacts with excess ammonia to form ammonium salts.

The SCR process is subject to catalyst deactivation over time due to physical deactivation and chemical poisoning of the catalyst. Catalyst suppliers typically guarantee a three to five year catalyst life for combustion turbine applications. Experience with SCR catalyst life in Washington State indicates that the actual service life of these SCR catalysts is at least twice that 3-year guaranteed life, and probably more. Power plants in Washington State combusting only natural gas has had minimal problems with their SCR catalyst systems due to deactivation or contamination from sulfur compounds in the natural gas fuel.

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 nitrogen oxides 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. The ammonia slip design rate for the proposed Project is a maximum of 5 ppmdv and is expected to usually be lower in actual operation. Testing in Washington State confirms that the ammonia slip rate is typically in the range of 1 ppmdv for a newer catalyst. Over years of operation, the catalyst slowly will lose performance capability. When this slip becomes less controllable (at about 4 ppmdv), the SCR catalyst is usually replaced. Permitting at 5 ppm has been the acceptable BACT level to allow an acceptable lifetime for the SCR catalyst. The plant typically will not operate at higher ammonia levels than necessary due to the cost of excess ammonia.

Capital costs for installation of an SCR system on each CT/HRSG have long been proven acceptable to EFSEC. Since SCR is equal to the best performing NO_X reduction technologies, BACT rules do not require a cost analysis if it is chosen as BACT. A cost analysis was not done for this Project. A NO_X emission rate of 2.0 ppmdv at 15% O_2 was proposed by GHE because it was equal to the best BACT decisions found.

3.2.1.6. NO_X BACT Conclusion

Based on the preceding BACT analysis, EFSEC concludes that the only technically feasible and commercially proven technology suitable for establishment of NO_X control BACT limits is an SCR system. 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, 3-hour average. At maximum operating rate on a cold day, this will result in a maximum emission of 20.0 lb/hr, 3-hour average per turbine. Annual NO_X emissions are limited to 87.5 tons per year from each turbine.

3.2.2. 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 low NO_X burner 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.

3.2.2.1. Review of Previous BACT Determination for CO

A review of EPA’s RBLC database from 2005 to the present and contacts with combustion turbine manufacturers indicate that the 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% O_2) with duct burners. It is in a NO_X and ozone nonattainment area.

The CPV Warren project in Virginia is permitted for 1.8 ppmdv when duct burners are not burning. With duct burners, the CO limit is 2.5 ppmdv. The plant site is located about 7 kilometers 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 2009.

There are many 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.

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:

1. Good Combustion Practices
2. EM_X (formerly $SCONO_X$)
3. Catalytic Oxidation

Good combustion practices in this design and size of turbine burners can reduce CO to the range of 10 to 15 ppm. Both the EM_X and catalytic oxidation technologies claim to be able to reduce CO to 2.0 ppmdv, so they are considered equally stringent for this Project.

3.2.2.2. Good Combustion Practices

Following up on the discussion in the first paragraph of this section, good combustion practices for turbine burners include design and operational practices to optimize both excess oxygen content and the "3 Ts" of combustion. The GE turbine's low NO_X burner design includes several stages of operation beginning at start-up and proceeding to normal operation. These stages are designed to safely and efficiently bring both the rotating and stationary components of a cold turbine up to the operating temperatures, pressures, and the shaft rotation speed of normal operation. For these GE turbines, normal operation of the burners is called "Mode 6." The burner goes into Mode 6 of operation at about 50-60 percent of maximum fuel (natural gas) feed rate. During normal operation, the turbine's CO production is rated at about 9-15 ppmdv at 15% O_2, but operating data from several plants has shown it is usually 6 ppmdv or lower. Because the initial burner stages are designed for duties other than efficiency, they have higher CO emission rates.

3.2.2.3. FM_X (formerly $SCONO_X$)

The EM_X system was described in the BACT analysis for control of NO_X emissions. 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 like those proposed for this Project. Several recent BACT analyses for EFSEC combustion turbine projects have determined that EM_X is not a cost-effective control technology, despite its claimed ability to control multiple pollutants.

As determined in the NO_X BACT section, because of EM_X's high cost per ton of pollutant removal, and the technical uncertainties surrounding the process, EFSEC determines that EM_X is not to be considered further as BACT for the control of CO emissions for the GHE Project.

3.2.2.4. Catalytic Oxidation

An oxidation catalyst removes CO and hydrocarbon materials from the turbine and duct burner exhaust stream by reacting them with oxygen in the hot gas stream to form carbon dioxide (CO_2). Platinum, or a mix of similar metals, is typically the active catalytic ingredient. Technical factors relating to the CO catalyst system include reactor design, optimal operating temperature, pressure loss to the system, and catalyst life.

The oxidation catalyst is usually located in the HRSG, downstream of the duct burner where the temperature is within 700 to 1,100ºF. As the exhaust gas flows through the catalyst, it causes a pressure drop of approximately 1.5 inches of water, which contributes to a slight loss in power output. 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.[5] A discussed above, the GE 7FA turbine can achieve about 9-15 ppmvd CO at loads between 60 and 100 percent when firing natural gas without additional controls. Experience in Washington State has shown that with addition of the oxidation catalyst, the turbine exhaust can meet a short-term limit of 2.0 ppmvd over the catalyst lifetime.

Catalyst systems are subject to loss of activity over time due to physical deactivation and chemical poisoning. Catalyst suppliers typically guarantee a 3-year catalyst life for combustion turbine applications. Experience with oxidation catalysts in Washington State indicates that the expected lifetime of an oxidation catalyst combusting natural gas should be at least twice this guaranteed 3-year lifetime, and probably more. With a fresh catalyst, CO will be controlled well below 1 ppm. As it ages, the ppm level of control will rise. When the CO cannot easily be controlled below 2.0 ppm, the catalyst is replaced.

Capital costs for installation of a catalytic oxidation catalyst system on each CT/HRSG have long been proven acceptable to EFSEC. Since an oxidation system is the best performing NO_X reduction technology, BACT rules do not require a cost analysis if it is chosen as BACT. A cost analysis was not done for this Project. A CO emission rate of 2.0 ppmdv at 15% O_2 was proposed by GHE because it was equal to the best BACT decisions found.

3.2.2.5. CO BACT Conclusion

Lean premix 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 12.2 pounds per hour, both on a 3-hour average. An annual CO limit per of 225 tons per year per turbine is proposed by GHE and accepted by EFSEC. As discussed later in Section 3.2.7.2, about two-thirds of this annual CO is due to estimated emissions for the maximum start-up/shutdown operating scenario.

3.2.3. 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 methane, ethane, and several other organic compounds that have negligible photochemical reactivity. Control of VOCs is first accomplished by providing good combustion practices as discussed in the CO BACT discussion. Add-on control devices such as catalytic oxidation can control VOCs further.

[5] "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

A survey of the RBLC database indicated that burning of a clean fuel (natural gas), good combustion practices, 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% O_2.

The CO BACT conclusion determined that an oxidation catalyst was to be installed for CO emissions control. Oxidation catalysts typically oxidize organic compounds at different rates depending on the chemical structure of the organic molecule. CO oxidation catalyst vendors say that typically the CO oxidation catalyst can remove up to 30 percent of the unburned methane, ethane, and propane, and up to 70 percent of smaller VOC compounds. Additional information from EPA supports the catalyst supplier's smaller VOC removal claim with data suggesting that the CO catalyst can remove smaller HAPs such as formaldehyde at approximately the same rate as it removes CO.

This analysis assumes that the oxidation catalyst removes up to 50 percent of the overall VOC emissions from each CT/HRSG system when designed to remove 90 percent of the CO.

GHE proposed catalytic oxidation in conjunction with good combustion practices as BACT for VOCs emitted by the combustion turbine. This design will meet a VOC emission limit of 0.0016 lb/MMBtu (as CH_4) when operated at full load and, 0.005 lb/MMBtu (as CH_4) when operated at partial loads. This equates to approximately 1 ppmvd at 15% O_2 in the stack gases at full load (with or without duct firing), and 3 ppmvd at 15% O_2 at 60 percent load. These figures are based on emissions rates supplied by the turbine supplier.

3.2.3.1. VOC BACT Conclusion

EFSEC determines that BACT for VOC for the turbines is use of the CO oxidation catalyst to also reduce VOCs. VOC emissions are limited to 3 ppmdv @15% O2 and 5.9 pounds per hour (1-hour average) from each turbine/HRSG exhaust stack. Also, 25.75 tons per year on a 12-month rolling total from each stack.

3.2.4. Sulfur Dioxide and Sulfuric Acid Mist Control

Sulfur dioxide (SO_2) is formed exclusively by the oxidation of the sulfur present in fuel. Some of the SO_2 may be converted (oxidized) to SO_3, which in turn can form sulfuric acid (H_2SO_4). Either the sulfuric acid can be emitted as sulfuric acid mist, or it can combine with ammonia to form an ammonium sulfate or bisulfate salt.

It is important to note that sulfur compound emissions are due to the sulfur content of the fuel. They are not controllable by good combustion practices like emissions of NO_X, CO, or VOC are. Sulfur is considered a "pass through pollutant." The permitted emission limits are based on the best information available to estimate the daily and annual average sulfur content of the natural gas fuel. If at some future time the sulfur content of the natural gas fuel rises above the design estimates, this is beyond the control of the Project. The SO_2 and H_2SO_4 permit limits have been modeled and their impacts analyzed as very protective of all National Air Quality Standards, PSD increments, and Air Quality Related Values.

3.2.4.1. Available Control Techniques

The most stringent "front-end" or pre-combustion SO_2 control method demonstrated for combustion sources is the use of low-sulfur fuel, such as natural gas. A possible "back-end" or post-construction control might be installation of a Flue Gas Desulfurization (FGD) system.

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

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

FGD systems are commonly employed in conventional pulverized coal plants, where the concentration of oxidized sulfur species in the exhaust is relatively high. If properly designed and operated, FGD technology can reliably achieve more than 95 percent sulfur removal there. They have not been used on a combustion turbine process. The pressure drop created by the FGD system could not be overcome by the combustion turbine without the addition of an induced draft fan, which would cause problems with the air/fuel mixture in the combustion turbine combustor. GHE proposed that FGD technology be considered technically infeasible for controlling SO_2 emissions from the Project's combustion turbine.

The next most stringent control is the use of a low sulfur fuel such as natural gas. Natural gas supply to the Project would be from the existing natural gas pipeline currently supplying Units 1 and 2. The natural gas enters the Williams system at the Sumas Station on the Canadian border, and flows to the Project through the large natural gas pipeline system in western Washington. The sulfur content of the Northwest Pipeline natural gas is tested hourly at the Sumas Station. No additional sulfur-based odorant is added to the pipeline gas consumed by GHE. The Project's natural gas fuel is expected to have a maximum daily average sulfur content (99th percentile) of 2.36 grains per 100 scf of gas and an average annual sulfur content of about 1.07 grains per 100 scf. H_2SO_4 emissions are calculated based on 33 percent of inlet sulfur oxidized to SO_3.

3.2.4.2. Sulfur Dioxide and Sulfuric Acid BACT Conclusion

GHE proposes and EFSEC agrees that the use of natural gas as fuel is BACT for controlling SO_2 and H_2SO_4 emissions from the combustion turbine/duct burners. SO_2 emissions will be limited to 14.15 lb/hr (1-hour average) and 7.19 lb/hr at a rolling annual average calculated monthly. H_2SO_4 emissions will be limited to 6.65 lb/hr (1-hour average), and 3.66 lb/hr at a rolling annual average calculated monthly. Natural gas sulfur content will be determined on a daily basis based on fuel analysis information from the natural gas suppliers, then used with fuel consumption measurements to determine daily emissions of SO_2 and H_2SO_4 from each turbine/HRSG.

Annual stack testing using EPA reference methods will provide a check on the sulfur in natural gas information provided by the supplier, and indicate how much sulfur is converted to sulfuric acid. Previous SO_2 and H_2SO_4 testing on Units 1 and 2 have proven compliance with permit limits, but have been problematic to determine the proportion of SO_2 reacted to H_2SO_4. Testing on Units 3 and 4 will hopefully provide this information.

3.2.5. Particulate and Particulate Matter Less Than 10 Microns Control

Particulate matter (PM) is defined as fine solid or semi-solid materials smaller than 100 microns in size. 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.

Particulates from natural gas consumption are very small, and all fit within the PM_{10} range, and this permit assumes that. The EPA's AP 42[6], indicates that almost all PM emissions from gas turbines fired on natural gas are below one micrometer in size. In the following sections of this document and in the accompanying PSD and NOC permits, all particulates will be referred to as PM_{10}, for PSD permitting purposes unless specific reference is otherwise made to $PM_{2.5}$.

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 cools and absorbs them into a liquid.

PM_{10} emission levels from natural gas combustion are extremely low in mass as well as small in size (typically much less than one micron in diameter). Testers are finding that flow samples

[6] 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

must be taken for up to four hours just to get enough samples to measure in the EPA reference test methods. The particulate emission level achieved by combusting natural gas using good combustion practices in modern, well-designed burners is comparable or even lower than control levels achievable by particulate control technologies such as bag filters, electrostatic filters, and venturi scrubbers. Particulates from natural gas combustion are 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.

EPA is currently reviewing changes to the condensable particulate matter test (Method 202). Condensable particulates are estimated at 80 percent of the measured PM_{10} for this permit according to information based on the current Method 202 test. The issue is that the condensable particulate test method (EPA RM 202) creates a positive bias (indicates more condensable PM_{10} than is actually emitted).[7] For this permit, total PM_{10} (filterable plus condensable) is evaluated, but following EPA guidance, only filterable $PM_{2.5}$ emissions are evaluated. As discussed previously, all particulate is probably about $PM_{0.1}$, so this evaluation procedure actually ends up showing the impacts of both filterable and total particulates independently.

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 good combustion practices 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 GHE to propose that the use of natural gas fuel and good combustion practices be BACT for all particulates emitted from this Project.

3.2.5.1. Particulate and PM_{10} BACT Conclusion

GHE proposes and EFSEC agrees 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 good combustion practices in lean premix dry low NO_X turbine burners and low NO_X duct burners. The proposed BACT emission limits are 456 pounds filterable plus condensable PM_{10} per 24 hours for each turbine/HRSG. An annual limit of 83.0 tons per year (filterable plus condensable) is also proposed. For $PM_{2.5}$, the proposed BACT emission limits are 114 pounds per 24 hours (filterable only) for each turbine/HRSG. An annual limit of 20.8 tons per year (filterable only) is proposed. Initial performance tests and annual testing using EPA reference methods are proposed annually for the first three years of operation. If these tests all show compliance, the annual testing may be reduced to once every five years. Failure of a test will require a retest and reinstate annual testing until another three consecutive years of testing show compliance.

[7] "In-Stack Condensable Particulate Matter Measurements and Issues," Louis A. Corio and John Sherwell, Journal of Air & Waste Management Association, Volume 50, pages 207-218, February 2000.

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.

3.2.6. Toxic Air Pollutants Control

Almost all of the toxic emissions from the proposed Project fall into the category of PM_{10} or VOC. Ammonia falls outside each of these because it is a gas, but not a VOC. This means that the same controls that were considered in the earlier BACT discussions for PM_{10} and VOC emissions are considered for toxic emissions other than ammonia.

3.2.6.1. PM_{10} Toxic Air Pollutants

Baghouses and electrostatic precipitators (ESPs) are frequently used to control PM_{10} emissions for electrical generation facilities not fueled by natural gas, such as coal-fired power plants. These PM_{10} controls were determined technically infeasible in the PM_{10} BACT Section 3.2.5 because particulates from natural gas combustion are so small that these controls cannot efficiently remove them. See Section 3.2.5 for a more complete discussion of these options. The arguments from that section apply equally well to the subset of these fine particulates that are toxic.

3.2.6.2. VOC Toxic Air Pollutants

VOC toxic emissions can be controlled by oxidation. As discussed in the VOC BACT Section 3.2.3, guidance indicates that an oxidation catalyst should control formaldehyde (the primary air toxic from natural gas combustion) to similar reduction levels as CO emissions. This means that the currently proposed CO oxidation catalyst should reduce formaldehyde emissions about 75 percent or more. The Project emissions estimate assumes a 50 percent reduction in total VOC due to the CO oxidation catalyst.

The Federal Combustion Turbine NESHAP[8] in 40 CFR 63 Subpart YYYY is currently staid for lean premix turbines and diffusion flame gas-fired turbines due to a court action, and EPA is considering dropping these two categories from the NESHAP.[9] Because of this, no NESHAP-related provisions are applicable or included in this permitting action.

[8] NESHAP and NSPS information for combustion sources is available from the EPA at http://www.epa.gov/ttn/atw/combust/list.html.
[9] Federal Register, August 18, 2004, page 51184.

3.2.6.3. Ammonia

Ammonia is not a federal Hazardous Air Pollutant (HAP), but it is a State of Washington Toxic Air Pollutant (TAP) listed in Chapter 173-460 WAC. Ammonia is used as a reactant in the SCR catalyst system to reduce NO_X emissions. See Section 3.2.1.4 which discusses both SCR and ammonia's part in the process. Ammonia that slips through the SCR catalyst bed is referred to as "slip." A search of the EPA RBLC database and the other permit information sources use for the NO_X BACT determination (Section 3.2.1.1) determined that the ammonia slip rate traditionally allowed has been 10 ppmdv or lower. Recent permits have reduced that to 5 ppmdv. The 5 ppmdv slip limit is proposed for this Project.

A further discussion of turbine toxics emissions regarding modeling is found in Section 4.2 of this document.

3.2.6.4. Toxic Air Pollutants BACT Conclusion

EFSEC determines that BACT for Toxic Air Pollutants for this Project is determined to be use of the CO oxidation catalyst to also reduce toxic VOCs. Ammonia emissions are limited to a maximum of 5 ppmdv and 18.5 pounds per hour (both at a 24-hour average) from each turbine/HRSG exhaust stack.

3.2.7. Turbine Start-Up and Shutdown

3.2.7.1. Description of Start-Up and Shutdown

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 Mode 6 (normal operation mode) which usually happens when reaching about 60 percent of turbine power. Start-up ends when normal temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules and the burner is operating in Mode 6. 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 Mode 6 operation are not obtained within a reasonable time.

Shutdown starts when ramping down from normal Mode 6 operation (between 60 and 100 percent turbine power generation capacity), and ends when fuel flow ends.

Start-ups for this Project are classified into two types—warm starts and cold starts. Warm starts occur when the turbine is restarted after being shut down for up to 48 hours. Cold starts occur when the turbine is restarted after being shut down for more than 48 hours.

An integrated microprocessor based control system will be provided for the turbine equipment, for data acquisition, and for data analysis. The control system will be used 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.

3.2.7.2. Emissions During Start-Up and Shutdown

The turbine manufacturer (General Electric) provided estimates of emissions during start-up and shutdown. GHE has also recorded NO_X and CO emissions during all start-ups and shutdowns of the existing Units 1 and 2. NO_X, CO, and VOC emissions increase during start-up because the low NO_X turbine burners take time to stage into normal low NO_X operating mode (Mode 6), and because the SCR and oxidation catalysts are not up to operating temperature yet. PM_{10} and SO_2 emissions are proportional to fuel flow, not combustion conditions, so their emission rate does not increase above normal operating levels during start-ups or shutdowns.

The duration and total emissions from a combustion turbine start-up depend on how long it has been shut down. Table 5 identifies start-up emissions and the duration of a combustion turbine start-up as submitted by GE, the turbine manufacturer. Note that once the combustion turbines reach 60 percent load, the SCR and oxidation catalyst will be operational and the combustion turbine emission rates will meet the proposed emission limits.

Table 5. Combustion Turbine Total Start-Up/Shutdown Emissions (per GE)

Scenario[a]	Time[b] (min)	NO_X	CO	SO_2[c] (1- and 3-hr)	SO_2[c] (24-hr)	SO_2[c] (annual)	PM	VOC
Cold Start	241	520	1,300	22.0	20.3	11.0	50	80
Warm Start	124	275	1,900	13.2	12.2	6.6	30	120
Hot Start	83	175	800	10.1	9.3	5.1	20	60
Shutdown	30	100	650	3.8	3.5	1.9	8	40

Emissions in pounds per event for the Units 3 and 4 combustion turbines.

a. Cold start – start-up following a 72-hour or greater period of non-operation. Hot start – start-up following 8 hours or less of non-operation. Warm start – start-up following between 8 and 72 hours of non-operation.

b. Time for both turbines to reach 60% load for start-up, and both turbines to go from 60% load to no operation for shutdown.

c. SO_2 start-up/shutdown emissions are based on the following assumed fractions of maximum full load operation emissions: cold start – 50%, warm start – 58.5%, hot start – 67%, shutdown – 70%.

Units 3 and 4 may be used to meet peak daily electrical demand, which will require frequent start-ups and shutdowns. Table 6 identifies short-term average emission rates for several operating scenarios when the combustion turbines are started, operated, and shut down per GE. Review of the table indicates CO emissions are much higher during start-ups than during normal operations; NO_X and VOC emissions are higher, but the increase is not as significant as with CO. Because SO_2 emissions depend solely on the quantity of fuel used, the lower operating rate during start-up results in lower SO_2 emissions. PM emissions are also lower during start-up.

Table 6. Short-Term Combustion Turbine Emission Rates Incorporating Start-Up and Shutdown (per GE)

Scenario	24-hr NO_X	1-hr CO	8-hr CO	1-hr SO_2	3-hr SO_2	24-hr SO_2	24-hr PM_{10}	24-hr $PM_{2.5}$	1-hr VOC
Hot Start/Operation/Shutdown	48.3	N/A	N/A	N/A	N/A	24.6	36.2	9.0	N/A
Warm Start/Operation/Shutdown	51.4	N/A	N/A	N/A	N/A	24.0	35.5	8.9	N/A
Cold Start/Operation/Shutdown	58.3	N/A	N/A	N/A	N/A	22.2	33.3	8.3	N/A
Hot Start/Operation	N/A	578	120	7.3	18.6	N/A	N/A	N/A	43.4
Warm Start/Operation	N/A	919	256	6.4	13.2	N/A	N/A	N/A	58.1
Cold Start/Operation	N/A	324	175	5.5	7.3	N/A	N/A	N/A	19.9
Operation/Shutdown	N/A	662	104	7.7	24.9	N/A	N/A	N/A	45.9
Worst Case Total	58.3	919	256	7.7	24.9	24.6	36.2	9.0	58.1

Pounds per hour for Units 3 and 4 combustion turbines. In all cases, the worst-case "normal" operation scenario was full load with duct burning. For pollutants with averaging periods too short to include both a start-up and a shutdown, separate average emission rates were calculated for start-up and shutdown, as shown in the left-most column.

GHE evaluated the annual emissions that would be created by each of the six operating scenarios using the GE data. Because the number and type of start-ups and shutdowns that will actually occur in a given year are difficult to predict, it was thought that scenarios with unrealistically frequent start-up and shutdown events could be compared to the annual average emission rates developed for continuous annual operation (which assume there are no start-ups or shutdowns), to determine which operating scenario would generate the maximum annual emissions. Table 7 shows the annual emission rates calculated for those six start-up/operation/shutdown scenarios, and identifies the maximum emission rates for each pollutant. In all cases, the operating period between start-up and shutdown was assumed to be 16 hours, and the operating scenario was assumed to be full load with duct burning.

Table 7. Annual Combustion Turbine Emissions Considering Six Possible Start-Up and Shutdown Scenarios, and Normal Full-Time Operation of Two Turbines (tons per year)

Scenario	NO_X	CO	SO_2	VOC	PM_{10}	$PM_{2.5}$
Cold SU/16h Op/SD/72h Down	59	111	12	14	32	7.9
Warm SU/16h Op/SD/70h Down	50	145	12	17	32	8.0
Warm SU/16h Op/SD/48h Down	67	193	16	23	43	11
Warm SU/16h Op/SD/10h Down	154	450	37	53	99	25
Hot SU/16h Op/SD/8h Down	153	310	41	48	108	27
Hot SU/16h Op/SD/6h7m Down[a]	166	335	44	52	116	29
Maximum Emission Rate	166	450	44	53	116	29

a. Tons per year. Assumes one start-up per day for each day of the year. SU = start-up. SD = shutdown. Op = operation. Down = not operating.

The maximum emission scenario is represented in the annual limits of the proposed permit for each pollutant. To make the new permit consistent with the existing permit of Units 1 and 2, it is proposed to define start-ups using two scenarios called warm or cold. Less than 48 hours of turbine downtime is called a warm start, and more than 48 hours is a cold start. Since both short-term and annual emissions are modeled at their maximum predicted rates, this permitting decision is protective of all NAAQS and PSD increments. Also, experience with Units 1 and 2 has shown that a reasonable time period limitation for these start-up modes is three and five hours, respectively. Review of NO_X and CO continuous emission monitor (CEM) measurements during start-up and shutdown has shown that after adding a 25 percent safety margin, show that a maximum limit of 875 pounds NO_X, 500 pounds of CO, and 150 pounds of VOC per start-up period is appropriate. No measurement data is available for VOC, so estimates of VOC emission rates supplied by GE are used instead. These hourly emissions were modeled for the simultaneous startup of 4 turbines and do not violate any NAAQS, including the new NO_X one-hour standard, and also have acceptable visibility impacts on Class I Areas. .

3.2.7.3. Start-Up and Shutdown BACT Conclusion

EFSEC determines that BACT for start-ups and shutdowns is to follow the start-up and shutdown procedures that are developed by the equipment manufacturers and documented by GHE in the equipment Start-up, Shutdown, and Malfunction Procedures Manual required by PSD permit. Start-ups will end when one of two events occurs: either the turbine(s) are operating in Mode 6 above 60 percent load and normal operating temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules as indicated by the above referenced manual, or else three (3) or five (5) hours have elapsed since first fire on a warm or cold start, respectively. Normal operating limits for NO_X, CO, and VOC are relieved while in start-up or shutdown mode. Per start-up period limits for NO_X, CO, and VOC of 875 lb, 500 lb, and 150 lb, respectively, are substituted. A site wide limit of 5,392 pounds of NOx per calendar day is added for protection of Class I Area visibility. Emissions of VOC are estimated using emission factors supplied by GE. All emissions are counted toward annual emissions. Start-ups are limited to a maximum of two warm start-ups per day. Annual emission limits on emissions of NO_X, CO, and VOC will limit the annual number of start-ups and shutdowns.

3.3. Auxiliary Boiler

One auxiliary boiler will serve the two proposed combustion turbines and the proposed steam turbine by providing steam for pre-startup equipment heating, as well as other miscellaneous services when steam is not available from the HRSGs. The auxiliary boiler will have a maximum rated heat input of about 30 MMBtu/hr, and will be fueled only by natural gas.

Pollutant emissions from natural gas boiler units include NO_X, PM_{10}, $PM_{2.5}$, CO, SO_2, and VOCs. Annual operation of the boiler is proposed to be equal to or less than 2,500 hours of the year at maximum capacity. For this small boiler with those restricted hours of operation, annual emissions will have a potential to emit (PTE) of about a ton or less for all regulated pollutants.

Ecology issued the "General Order for Small Water Heaters and Steam Generating Boilers" on August 8, 2008.[10] An extensive BACT analysis was done by Ecology in support of this general order. The order covers natural gas fueled boilers fired at up to 50 MMBtu/hr. Since the auxiliary boiler proposed by GHE is fired at 30 MMBtu/hr, it is within the range of this general order. The general order is applicable only to boilers being installed in counties where Ecology is the local air authority, and it is not applicable for boilers being installed as part of a PSD permit such as the current Project, but it does indicate the BACT considerations that Ecology considers appropriate for this size and type of boiler. GHE did their own search of the EPA RBLC and other sources to determine their BACT recommendations for this boiler. Their search confirmed the BACT recommendations of Ecology's general order. Those BACT recommendations are:

General Order BACT recommendations:

- NO_X: 9 ppmdv @ 3% O_2
- CO: 50 ppm @ 3% O_2
- SO_2: Use of natural gas as fuel
- Other pollutants: No limitations

EFSEC has recently permitted a similar boiler at another EFSEC regulated power generating facility.[11] This permitting action allowed a NO_X limit of 12 ppmdv @ 3% O_2 rather than 9 ppm because the higher limit allowed more reliable operation with little impact on the environment due to the low pollutant emission rates of the boiler. The CO limitation was maintained at 50 ppmdv. An initial source test and testing every 60 months after that for NO_X and CO using EPA Reference Methods was required. Testing of NO_X and CO using other analyzers (approved by EFSEC) was required every four QA operating quarters following a calendar year with method testing in order to minimize emissions and provide a reasonable assurance that the boiler is operating properly. If the tests show higher than expected test readings, corrective maintenance and retesting is required. Since these methods are not federally approved, they are part of the NOC portion of this permit.

GHE showed in its application that the limited operating period for the auxiliary boiler resulted in relatively low annual emissions of SO_2, VOC, PM_{10}, and $PM_{2.5}$. This led to the conclusion that investment in add-on controls would not be cost-effective even if they were feasible. Because of this, GHE proposed that the use of natural gas and good combustion practices as BACT for the auxiliary boiler, and proposed that there be no emission rates as BACT limits for SO_2, VOCs, PM_{10}, and $PM_{2.5}$. GHE's mass balance calculations based on the sulfur content of the expected source of natural gas indicated SO_2 emissions would be approximately 0.0058

[10] Available on the Department of Ecology's Air Quality Program web page at http://www.ecy.wa.gov/programs/air/AOP_Permits/Boiler/GeneralOrders.htm.
[11] Auxiliary Boiler Project at the PacifiCorp Chehalis Generating Facility permit available on the EFSEC web site at http://www.efsec.wa.gov/cgf.shtml.

lb/MMBtu (hourly average), 0.0054 lb/MMBtu (24-hour average), and 0.0029 lb/MMBtu (annual average). Boiler vendor information indicated that hourly VOC and PM_{10} emissions would be 0.004 lb and 0.005 lb/MMBtu, respectively. $PM_{2.5}$ emissions were based on the filterable portion of the calculated PM_{10} emission rate, using fraction provided in AP-42 Section 1.4. The pounds per hour represented by these emissions rates are shown in Table 8. They are very small when compared to the turbine's emissions.

3.3.1. Auxiliary Boiler BACT Decision

EFSEC determines that the boiler shall not operate more than 2,500 hours per year, with natural gas as its only fuel. BACT for NO_X emissions is 12 ppmdv @ 3% O_2. BACT for CO is 50 ppmdv @ 3% O_2. Both shall be accomplished due to the design of the boiler's low NO_X burner. Opacity is limited to five percent in accordance with EPA Method 9. Compliance may be monitored monthly by EPA Method 22. If Method 22 indicates opacity greater than zero, then GHE will take action to find and correct the problem. A Method 9 or other EFSEC-approved test shall be performed within two weeks to confirm that the problems are corrected. 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 EFSEC within every four operating quarters after a calendar year when EPA Method testing is done. If these tests show exceedance of NO_X or CO limits, GHE 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 SO_2, PM_{10}, $PM_{2.5}$, VOC, and toxic air pollutants is use of natural gas fuel and good combustion practices.

3.4. Cooling Tower

3.4.1. Description of Cooling Tower System

The cooling system proposed for the expansion Project consists of a circulating water system that will utilize two five-cell mechanical draft-cooling towers to support operations of the steam turbine generator. In this type of cooling tower, fans at the top of each cooling tower cell maintain a flow of air through the cooling tower. Circulating water pumps move the water from the steam condenser, where it picks up heat, to the top of the cooling tower. At the top of the cooling tower, the warm water is distributed onto a perforated deck. The water then falls through the perforations and is cooled by evaporation as it falls through baffles (called "fill") to a basin at the bottom of the tower. Cool water from the cooling tower basin is returned to the condenser via the circulating water pumps.

3.4.2. Emissions

Emissions from the cooling tower are expected to consist only of particulate matter. This discussion will refer to them as PM_{10}, but their actual size is unknown. There is no EPA test to actually measure them. These emissions originate from the dissolved solids contained in droplets of cooling water, called “drift,” that escape in the air stream exiting the cooling tower. The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and the efficiency of the drift eliminator. Drift usually falls close (on or near the plant site) because it is cool and is emitted close to the ground.

Drift eliminators are incorporated into the tower design to remove as many droplets as practical from the air stream before the air exits the tower. PM_{10} emissions from cooling towers are usually estimated by using the tower’s design drift rate and the Total Dissolved Solids (TDS) concentration of the tower’s incoming cooling water. A high efficiency drift eliminator with a drift rate of 0.0005 percent is proposed for the Project. That is a very low drift rate, equivalent to Lowest Achievable Emission Rate (LAER) permitting decisions for projects sited in particulate nonattainment areas.

The only alternative to a wet cooling tower is the use of a dry (i.e., non-evaporative) cooling system. Dry cooling is usually used to reduce the water consumption of the plant, rather than as BACT for PM_{10} emissions. This option involves use of a very large, finned-tube water-to-air heat exchanger (think of a super large car radiator or something similar) 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. Air cooling equipment is more costly than wet cooling towers. In addition, it is less efficient because it has to cool water using the heat capacity and temperature differential of ambient air rather than evaporate water at the ambient wet bulb temperature.

3.4.3. Cooling Tower BACT Conclusion

GHE proposes, and EFSEC agrees, that installation and operation of drift eliminators with a drift loss rate of 0.0005% 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 eliminators are installed in accordance with its installation criteria.

GHE is required to submit to EFSEC a methodology they will use to estimate particulate emissions from the cooling tower. The methodology shall be reviewed and approved by EFSEC prior to the first operation of the cooling tower. PM_{10} emissions shall be limited to 19 lb/day on a rolling annual average, estimated quarterly.

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.

3.5. Emergency Generator and Firewater Pump

3.5.1. Description of Emergency Generator and Firewater Pump

A pump powered by a new nominal 275 hp diesel engine will be installed to provide water for fire suppression when power from the grid is not available to run the electric firewater system (both electric motor powered and diesel engine powered firewater pumps are in the system). In addition, a new nominal 600 hp diesel-fueled engine will drive a 400 kw generator to provide emergency power when power from the grid is not available. Both engines will burn ultra-low sulfur distillate oil. To minimize NO_X emissions, GHE committed to use of a Tier 4 engine for the emergency generator. Other than in plant emergencies, each engine will be operated no more than 100 hours per year for routine testing, maintenance, and inspection purposes.

3.5.2. Emissions

Although the engine makes and models have not yet been specified, the emission standards for stationary engines in 40 CFR Part 60 Subpart IIII (Stationary Compression Ignition Reciprocating Engine NSPS) were used to calculate criteria pollutant emissions.[12]

Table 8. Criteria Pollutant Emissions From Emergency Diesel Engines

		NO_X [c]	CO	SO_2 [d]	PM_{10}	$PM_{2.5}$	VOC
Emergency Generator	lb/hp-hr[a]	0.0033	0.0058	0.000012	0.0003	0.0003	0.0066
	lb/hr	1.97	3.45	0.00728	0.197	0.165	3.95
	ton/yr[b]	0.099	0.173	0.00036	0.0099	0.0082	0.197
Firewater Pump Engine	lb/hp-hr[a]	0.0049	0.0043	0.000012	0.0007	0.0005	0.0049
	lb/hr	1.36	1.18	0.00334	0.181	0.151	1.357
	ton/yr[b]	0.068	0.059	0.00017	0.0090	0.0076	0.068

a. Emission factors based on 40 CFR Part 60 Subpart IIII, Table 4 (except SO_2 and NO_X, see notes c and d).
b. Annual emissions based on 100 hours of generator testing/maintenance per year.
c. Conservatively, assumed both NO_X and VOC emissions equal the Subpart IIII limit on the sum of NO_X and VOC for the Firewater Pump engine. NO_X emission factor for the emergency diesel generator was estimated from interim Tier 4 limits for 2011 engines.
d. SO_2 based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.015% by weight (8.09e-3 x %S). The SO_2 emission factor from AP-42 Section 3.3 was not used because it is based on an unknown fuel sulfur content, and the Section 3.4 emission factor assumes complete conversion of sulfur to SO_2.
e. Filterable $PM_{2.5}$ emissions were assumed 25% of PM_{10} emissions, and total $PM_{2.5}$ emissions were assumed equal to PM_{10} emissions.

3.5.3. BACT Discussion

A review of the RBLC database and other sources showed the BACT control decisions for these types of engines included good engine design and proper operating practices, use of low sulfur fuel, limited operating hours, proper engine maintenance, and good combustion practices. GHE

[12] Subpart IIII limits the sum of NO_X and VOC emissions. A conservative estimating procedure assumed the engine would emit both NO_X and VOC at the standard for the sum of the two pollutants.

proposes to do all of these. New engines meeting the federal standards for the engine year they are manufactured are proposed. Use of diesel fuel oil with the ultra low sulfur content of 15 ppm or less sulfur is proposed. The GHE application originally proposed limiting annual operation for testing, maintenance, and training to 26 hours per year, but after further discussions with plant personnel and additional modeling, an annual limit of 100 hours per year as allowed in the Subpart IIII NSPS was proposed.

Addition of SCR for NO_X control and an oxidation catalyst for CO control were considered technically feasible. Non-Selective Catalytic Reduction (similar to an automobile catalytic converter) was not considered technically feasible because it operates in a fuel-rich environment, not the lean burn environment of these engines.

A cost analysis was completed for the SCR option. Using the original 26 hours/year operation restriction (138 pounds of NO_X/year total emissions for both units); the SCR option for the firewater pump was estimated to cost $4.9 million/ton of NO_X removed, and for the emergency generator $1.7 million/ton. At 100 hours of operation, this was still not proposed as cost-effective.

A cost analysis was also completed for the oxidation catalyst option. Using the original 26 hours/year operation restriction (120 pounds of CO/year total emissions for both units), the oxidation catalyst option for the firewater pump was estimated to cost $669,000/ton of CO removed, and for the emergency generator $428,000/ton. At 100 hours of operation, this was still not proposed as cost-effective.

3.5.4. Emergency Generator and Firewater Pump BACT Conclusion

GHE proposes, and EFSEC agrees, that BACT for each engine includes an annual limitation of 100 hours of operation for maintenance, testing, and training. Ultra low sulfur (15ppm S) diesel fuel is BACT for the emergency generator and firewater pump fuel. Both engines shall meet the applicable federal new engine standards (40 CFR 60 Subpart IIII) for engines sold in 2010 or in the year of purchase, whichever is later, with the emergency generator engine meeting the Tier 4 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. Since all pollutant emissions from these units are estimated to be less than one ton per year, they are not required to be reported.

4. AMBIENT AIR QUALITY IMPACTS ANALYSIS

4.1. 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 2.4 of this Technical Support Document, nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds

(VOCs), particulates less than 10 microns (PM_{10}), particulates less than 2.5 microns ($PM_{2.5}$), sulfur dioxide (SO_2), and sulfuric acid mist (H_2SO_4) are all emitted in PSD significant quantities from this Project.

An air quality analysis can include up to three parts: Significant Impact analysis, National Ambient Air Quality Standards (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. The PSD Increment analysis is used 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, Air Quality Impacts Analysis is done in two sections: an analysis of local 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. This usually includes impacts on Class I areas for projects in Washington State (done in Chapter 6 of this document).

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

AERMOD was applied to both criteria pollutant and TAP emissions using the regulatory defaults in addition to the options and data discussed in this section. The most recent version (Version 07026 which was the most recent version when the modeling protocol was approved in June 2009) 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 Elma, 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 analysis conservatively assumed that 100 percent of the emitted NO_X is converted to NO_2.

A representative one-year meteorological dataset (May 20, 2002–May 19, 2003) for the AERMOD dispersion model was prepared for the Satsop, Washington area using available surface meteorological data, upper air meteorological data, and the AERMOD meteorological preprocessor AERMET (Version 06341). This section describes the data and procedures used to generate the meteorological data set.

To evaluate the potential ambient air pollutant concentrations (i.e., impacts on air quality) attributable to Units 3 and 4, the emission rates associated with operating scenarios described in Section 5.1.2.1 were applied in the dispersion modeling analyses.[13] Note that this subsection

[13] Two $PM_{2.5}$ modeling analyses were conducted, one with filterable $PM_{2.5}$ per EPA Region 10 guidance, and one with total $PM_{2.5}$ (equal to PM_{10}) at the request of Ecology.

addresses emissions during normal (power generating) operation; start-up and shutdown emissions are evaluated in the next subsection.

4.1.2. Modeling Results for Local Air Quality Impact Assessment

Table 9 compares maximum concentrations predicted by the model simulations with the applicable Significant Monitoring Concentrations (SMCs) and the Significant Impact Levels (SILs) established in WAC 173-400-113(3). SMCs are thresholds that indicate whether pre-construction monitoring of background air quality is appropriate. The SILs represent incremental, project-specific impact levels that Washington State accepts as insignificant with respect to maintaining compliance with the NAAQS, WAAQS, and PSD increments. If a pollutant's modeled impact is less than its SIL, then no further analysis for compliance with NAAQS, WAAQS, or PSD increments is required.

Table 9. Maximum Predicted Criteria Pollutant Concentrations Attributable to Units 3 and 4 (μg/m^3)

Pollutant	Averaging Period	Maximum Concentration[a]	SMC	SIL	Over the SIL?
NO_2	Annual	0.0889	14	1	No
	1-hour	See the paragraphs following this table and Table 10			
CO	1-hour	365	N/A	2,000	No
	8-hour	18.1	575	500	No
SO_2	1-hour[d]	See the paragraphs following this table and Table 10			
	3-hour	9.99	N/A	25	No
	24-hour	1.38	13	5	No
	Annual	0.0311	N/A	1	No
PM_{10}	24-hour	2.71	10	5	No
	Annual	0.127	N/A	1	No
$PM_{2.5}$ (filterable)	24-hour	0.836	N/A	N/A[c]	N/A
	Annual	0.0485	N/A	N/A[c]	N/A
$PM_{2.5}$ (total)	24-hour	2.71	N/A	N/A[c]	N/A
	Annual	0.127	N/A	N/A[c]	N/A

a. Maximum from all operating scenarios, ambient conditions, and turbine types provided by GE Energy.
b. SIL = Significant Impact Level, from WAC 173-400-113(3) except as noted.
c. SMCs and SILs for $PM_{2.5}$ have been proposed but have not been promulgated.
d. This refers to current standard. See following paragraph and Table 10 for discussion of new 1-hour SO_2 standard.

Because SILs have not been promulgated for $PM_{2.5}$, GHE evaluated total $PM_{2.5}$ concentrations and compared them to the $PM_{2.5}$ NAAQS. The maximum average background concentration (17.1 μg/m^3) was added to the maximum predicted concentration (2.71 μg/m^3), showing a total concentration of 19.8 μg/m^3. This is less than the $PM_{2.5}$ ambient air quality standard (35 μg/m^3). After additional rulemaking has occurred, an analysis of PSD Class II increments will be required, but the major and minor source baseline dates have not been set for $PM_{2.5}$, making it impossible to determine which existing sources consume increment.

The 100 ppb (188 µg/m^3) 1-hour NO_2 NAAQS became effective on April 12, 2010. A new 75 ppb (196 µg/m^3) SO_2 standard was signed on June 2, 2010, and published in the Federal Register on June 22, 2010. It became effective August 23, 2010. EPA issued its initial guidance concerning the implementation of the 1-hour NO_X standard on June 29, 2010.[14] EPA issued guidance concerning the implementation of the 1-hour SO_2 NAAQS for the PSD Program on August 23, 2010. Normal operation of both the two new turbines and the two existing turbines (four units) were modeled for these two new standards. The results are shown in Table 10.

Table 10. One-Hour NO_X and SO_2 NAAQS Impacts From Normal Operations

Pollutant	Averaging Period	Percentile	SIL (µg/m3)	Two New PGUs (µg/m3)	Two New PGUs With New Boiler and Generator (µg/m3)	Total Concentration (µg/m3)	NAAQS (µg/m3)
Nitrogen Dioxide[a]	1-hour	98th	7.52	4.8	82.35	131.3 (157.7)[b]	188
Sulfur Dioxide[c]	1-hour	100th	7.85	40.76[d]	40.76[c]	57[e]	196

a. Nitrogen dioxide concentrations assume a 90% conversion of NO_X to NO_2.
b. Two 1-hour NO_X 98th percentile backgrounds used: 48.92 µg/m^3 from Moyie Springs, Idaho, and (75.3 µg/m^3 from Portland, Oregon).
c. SO_2 impact of two turbines broke the recommended 3 ppb (7.85 µg/m^3) SO_2 SIL, so 40.76 is the maximum cumulative impact of all four turbines during normal operation. Since only one year of SO_2 data was used, the highest impact was appropriate rather than the 99th percentile.
d. 99th percentile daily 1-hour maximum SO_2 concentration is 23.05 µg/m^3 for all four turbines at maximum normal operation.
e. Background SO_2 16 µg/m^3 based 2002-2003 on-site 1-hour SO_2 data.

These results indicate that the Project's NO_X and SO_2 emissions will not violate the new standards. The turbines normal emission have little influence on the maximum predicted 1-hour average NO_2 concentration when a diesel engine is operating because turbine emissions are from tall stacks that do not interact with the emissions from the short stacks of the auxiliary boiler and emergency generator.

4.2. Start-Up and Shutdown

To demonstrate that ambient air quality standards will not be exceeded during start-up, the start-up scenario emission rates were modeled using AERMOD. CO and NO_2 are the only criteria pollutants with short-term standards expected to increase significantly during start-up when compared to normal operation. For the 1-hour NOx Standard's impact analysis, GHE used the PVMRM option of AERMOD to model the impact of all four turbines starting up simultaneously, each operating at the maximum hourly emission rate seen during startup of 234

[14] "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program," by Stephen D. Page, Director of OAQPS, June 29, 2010. This guidance includes June 28 memos from Anna Marie Wood and Tyler Fox.

lbs/hr. This was a recent analysis done in September 2010, well after the main application materials were submitted. A discussion of this modeling is included as Appendix A.

Table 11 presents a summary of the results of the start-up simulations, and indicates that none of the applicable ambient standards would be exceeded as a result of start-up or shutdown.

Table 11. Maximum Predicted Start-Up Analysis Criteria Pollutant Concentrations ($\mu g/m^3$)

Pollutant	Averaging Period	Worst-Case Start-Up[a]	Background	Total[b]	NAAQS[c]	Over AAQS?
NO_2	1-hour	98.3[e]	48.9 (75.3)	147.2(173.6)	188	No
	Annual[d]	0.250	34.0	34.3	100	No
CO	1-hour	2,536	7,021	9,557	40,000	No
	8-hour	88.2	5,266	5354	10,000	No

a. Maximum from all start-up scenarios of 4 turbines starting simultaneously.
b. Sum of the maximum predicted concentration attributable to GHE during start-up and the background concentration.
c. NAAQS = National Ambient Air Quality Standard
d. Annual NO_2 was assumed 75% of emitted NO_X.
e. 99[th] percentile NOx value. See Appendix A for demonstration that this is protective of the NAAQS.

4.3. Toxic Air Pollutants

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAPs) 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. The quantities of all TAPs known to be emitted from the turbines Units 3 and 4 (with duct burners) were estimated and screened against the small quantity emission rates in the version of WAC 173-460 adopted by current EFSEC regulations (March 1, 2005).

TAP emissions exceeding the small quantity emission rate exclusion were modeled to determine their maximum ambient concentrations. These maximum ambient concentrations were compared to the respective acceptable source impact levels (ASIL) listed in WAC 173-400. These ASILs are not health effect levels, but conservative thresholds that, if exceeded, indicate the need for further investigation of the effects of the TAP on ambient air quality and human health. Table 12 compares the TAPs modeled, the modeled concentration impacts, and their respective ASIL.

Table 12. Toxic Air Pollutants Significant Impact Level Modeling Results (µg/m^3)

Compound	CAS #	Averaging Period	Class A ASIL	Class B ASIL	Maximum Predicted[a]	Over ASIL?
1,3-Butadiene	106-99-0	Annual	0.0036	-	0.0000038	No
Acetaldehyde	75-07-0	Annual	0.45	-	0.00035	No
Acrolein	107-02-8	24-hour	-	0.02	0.00138	No
Ammonia	7664-41-7	24-hour	-	100	2.11	No
Arsenic	7440-38-2	Annual	0.00023	-	0.00000074	No
Benzene	71-43-2	Annual	0.12	-	0.000112	No
Beryllium	7440-41-7	Annual	0.00042	-	0.00000004	No
Cadmium	7440-43-9	Annual	0.00056	-	0.00000408	No
Chromium (hexavalent)	18540-29-9	Annual	0.000083	-	0.00000021	No
Formaldehyde	50-00-0	Annual	0.077	-	0.00114	No
Nickel	7440-02-0	Annual	0.0021	-	0.00000778	No
Nitric Oxide	10102-43-9	24-hour	-	100	1.888	No
Polyaromatic Hydrocarbons	PAH	Annual	0.00048	-	0.0000192	No
Propylene Oxide	75-56-9	Annual	0.27	-	0.000253	No
Sulfuric Acid	7664-93-9	24-hour	-	3.3	0.759	No

a. Maximum from all operating scenarios.

Table 12 illustrates that model predicted concentrations associated with emission increases from the proposed Grays Harbor Energy Center units would not exceed the EFSEC-adopted ASILs.

The final status of the Combustion Turbine NESHAP is uncertain at this time. Subpart YYYY has been staid by the courts while EPA continues consideration of the toxicity factor for formaldehyde and whether to continue the category delisting process.[15] If future NESHAP requirements become applicable, they will become part of the Title V permit for the Project.

Since there were no TAPs that exceeded their ASIL screening values, no additional toxics review is required. Because of this, EFSEC concludes that no adverse health impacts are expected to occur due to the increase in toxic pollutants emitted from the Project.

4.4. 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

[15] August 9, 2006, e-mail from Madonna Narvaez of EPA, Region 10.

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 in Table 11 show that modeled maximum ammonia impacts will be well below the ammonia ASIL found in Chapter 173-460 WAC.

EFSEC concludes that 5.0 ppmdv ammonia emission limits for the GHE Units 3 and 4 Project does not threaten human health and is appropriate for the Project.

4.5. 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 GHE Units 3 and 4 Project's NO_X and VOC emissions exceed 100 tpy, so an ozone impact analysis on the Project's emissions was done.

To do the ozone impact analysis, GHE acquired the relevant input data and control files and then replicated the MM5/SMOKE/CMAQ runs performed by Washington State University for the Puget Sound Clean Air Agency (PSCAA) and Oregon Department of Environmental Quality in support of the various ozone studies conducted by those organizations. The scenarios in question simulate the July 26-28, 1998 ozone episode, which was meteorologically more severe than the 1996 case used previously. ENVIRON performed a "base case" scenario that closely resembled those of the PSCAA and Portland SIP studies, and a "PTE scenario," which was comprised of all base case scenario emissions in addition to the maximum post-project emissions from the GHE facility.

The maximum change to 8-hour average ozone concentrations between the PTE and base case scenarios is an increase of 2.25 parts per billion (ppb) in the cell adjacent to the facility. The spatial variation of the difference between the two scenarios during the period with the maximum difference is quite localized, falling to less than 0.33 ppb within about 20 km of the facility.

The largest increase in 8-hour ozone concentration near a Class I area is about 0.01 ppb near Mount Hood Wilderness Area. This is less than one percent of the relevant NAAQS, indicating that the facility will not cause or significantly contribute to degradation of natural wild areas. The largest increase in 8-hour ozone concentration near the Enumclaw (Mud Mountain, a traditionally high ozone location in the Puget Sound area) observation site is less than 0.0004 ppb.

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[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., page 12, 1997.

5. ADDITIONAL IMPACTS ANALYSIS

PSD regulations and guidance require an additional impact analysis for the effects of emissions on local soils, vegetation, and visibility from the source or modification under review, and from associated growth in the area surrounding the Project.

Growth Analysis: During construction, there would be an average of 270 and as many as 560 workers employed at the site. Local demand for skilled crafts people would increase. However, this demand would be temporary (less than two years).

Units 3 and 4 would consume natural gas delivered by pipeline. GHE's product, electricity, would 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. Operation of the facility will require a work force of approximately 31 people. Grays Harbor Energy does not expect Units 3 and 4 to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

Soils and Vegetation Analysis: Based on the results of the dispersion modeling analyses, facility emissions are expected to have a negligible effect on soils and vegetation. Project emissions that have the most potential to affect soils and vegetation are those that contain either sulfur or nitrogen. The maximum-modeled impacts of these emissions are well below all federal permitting modeling and monitoring significance levels. These levels are intended to be protective of soil and vegetation as well as human health.

For emissions of NO_X (assuming full conversion to NO_2), potential plant damage could begin to occur with 24-hour NO_2 concentrations of 15 to 50 parts per billion (ppb) (USFS, 1992). From the modeling results, the maximum annual concentration of NO_2 is 0.0889 microgram per cubic meter (μ/m^3) (about 0.1 ppb). The potential impact on local agriculture is expected to be negligible.

Visibility Impairment Analysis: The local visibility impacts of the Project should be negligible. Natural gas combustion does not typically produce any visible particulate emissions. The turbine exhaust stack emissions will typically be clear, and are limited to an opacity of five percent. This amount of opacity is just barely perceptible. Under some conditions, water might condense to form a steam plume. Units 3 and 4 will require a 10-cell cooling tower to exhaust waste heat. The cooling tower cells will produce visible water vapor clouds that vary in size depending on meteorology and operational factors. Visibility impacts on more distant Class I areas are discussed in the next section.

6. CLASS I AREAS IMPACTS ANALYSIS

Federal[17] and Washington State[18] 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 Federal Land Managers (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. Distances from the Project to Class I areas within about 200 km are shown in Table 13.

Table 13. Class I Area Distance From Proposed Project Site

Class I and Other Areas of Interest	Distance (km)
Alpine Lakes Wilderness	147
Glacier Peak Wilderness	198
Goat Rocks Wilderness	145
Mt. Adams Wilderness	158
Mt. Hood Wilderness	208
Mt. Rainier National Park	115
Olympic National Park	58
Columbia River Gorge National Scenic Area[a]	171

a. The Columbia River Gorge National Scenic Area is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

An important note for the reader of this Class I Area Impacts Analysis: The impacts analysis that follows is more complicated than a normal analysis. This one has four versions of the same analysis in several areas. Two versions are created because EFSEC requested that GHE analyze the impacts on Class I areas of the two turbine Project both on its own, and combined with the impacts of the two existing turbine emissions. The second two are in the visibility impacts section only. EPA is updating its analysis procedures, so GHE did the visibility analysis with both the traditional procedure and the new procedure that is not final yet, but shows much promise.

[17] 40 CFR 52.21 (p)
[18] WAC 173-400-117

The short-term emission cases simulated for the Class I analysis assume each source would be operating under the condition the results in the highest possible emission rate for each pollutant. The highest NOx emissions occur during startup conditions. The simulations assume proposed Units 3 and 4 would perform a 5-hour cold startup followed by 19 hours of operating under the highest possible load and that this case could occur for any day in three years. The cumulative analysis requested by the FLMs assumes existing Units 1 and 2 would also perform a 5-hour cold startup followed by 19 hours of maximum load. Although such an emission could occur on a single day, the realities of the power market do not anticipate such operation on a frequent basis.

6.1. Model Selection and Procedures

The EPA's *Guideline on Air Quality Models* (codified as Appendix W to 40 CFR Part 51, commonly referred to as the *Guideline*) identifies the CALPUFF modeling system as the EPA's preferred model for long-range transport assessments and for evaluating potential impacts on Class I areas. Potential impacts to AQRVs of concern were assessed using Version 5.8 of the CALPUFF modeling system; the release date of the versions used is June 23, 2007.

The CALPUFF modeling procedures follow the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM)[19] and the FLMs Air Quality Related Values Workgroup (FLAG),[20] outlined in the FLAG Phase I Report (December 2000) (IWAQM 1998, FLAG 2000). Per discussions with the FLMs, the procedures also incorporate aspects of proposed revisions to both the IWAQM and FLAG Phase I guidance (EPA et al. 2009, USFS et al. 2008).

The ammonia background level was assumed to be 17 ppb. An ozone background concentration of 60 ppb was used.

Meteorological data sets were obtained from the UW's numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5). The AQRV analysis used three years of hourly 4-km horizontal mesh size MM5 output data from January 2003 to December 2005. The UW MM5 datasets with a 12-km horizontal mesh size have also been used to assess industrial sources subject to BART review, as part of the EPA Regional Haze Rule. For the current analysis, the 4-km mesh size simulations were used in order to better resolve the flow in the complex terrain surrounding the Grays Harbor Energy Center site in the Chehalis River valley.

[19] IWAQM Phase 2 report available at http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf.
[20] FLAG information and reports available on NPS website at http://www.nature.nps.gov/air/permits/flag/index.cfm.

6.2. Criteria Pollutant Concentrations

Table 14 summarizes the predicted maximum criteria pollutant concentrations and compares them to the Class I SILs[21] and the Class I PSD increments. Concentrations lower than the SILs indicate insignificant consumption of the Class I increment. Such concentrations are also much lower than pollutant levels thought to adversely affect vegetation (Peterson et al. 1992).[22] The CALPUFF modeling results indicate that criteria pollutant concentrations attributable to the Project (the proposed new Unit 3, Unit 4, and associated sources) are less than the Class I area SILs in all Class I areas and the Columbia River Gorge National Scenic Area (CRGNSA).

Table 14. Predicted Class I Area and CRGNSA Criteria Pollutant Concentrations (μg/m^3)

Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes WA	0.0004	0.0491	0.0023	0.0205	0.0068	0.0003
Glacier Peak WA	0.0001	0.0257	0.0012	0.0089	0.0031	0.0001
Goat Rocks WA	0.0002	0.0304	0.0013	0.0185	0.0055	0.0001
Mt. Adams WA	0.0001	0.0195	0.0009	0.0175	0.0033	0.0001
Mt. Hood WA	0.0000	0.0308	0.0006	0.0060	0.0031	0.0001
Mt. Rainier NP	0.0006	0.0788	0.0029	0.0291	0.0099	0.0004
Olympic NP	0.0018	0.1437	0.0044	0.1596	0.0313	0.0007
Columbia River Gorge[b]	0.0002	0.0373	0.0012	0.0145	0.0048	0.0001
Class I Area Max. Conc.[b]	0.0018	0.1437	0.0044	0.1596	0.0313	0.0007
EPA Proposed SIL[c]	0.1	0.3	0.2	1	0.2	0.1
FLM Recommended SIL[c]	0.03	0.27	0.08	0.48	0.07	0.03
Class I Area PSD Increment[d]	2.5	8	4	25	5	2

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

Table 15 summarizes the results for the modeling simulations that included emissions for existing emission Units 1 and 2. The predicted cumulative concentrations are about double those attributable to Units 3 and 4, but still much less than the applicable PSD Class I increments. Note the simulations were performed using maximum potential emissions for existing project

[21] Currently there are two sets of Class I SILs, those proposed by EPA, and those recommended by the FLMs. These proposed and recommended SILs were obtained from the Federal Register, Vol. 61, No. 143, p. 38292, July 23, 1996.
[22] Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in the Pacific Northwest, USDA Forest Service PNW-GTR-299, May 1992, available at http://www.fs.fed.us/pnw/pubs/pnw_gtr299.pdf.

sources. Since according to regulatory guidance, PSD increment consumption from existing sources is based on actual emissions, the results shown in Table 15 overstate increment consumption attributable to Grays Harbor Energy Center cumulative source emissions.

Table 15. Predicted Class I Area and CRGNSA Criteria Pollutant Concentrations Including Existing Grays Harbor Energy Center Sources (µg/m^3)

Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes WA	0.0009	0.1061	0.0052	0.0403	0.0135	0.0006
Glacier Peak WA	0.0003	0.0541	0.0027	0.0175	0.0059	0.0003
Goat Rocks WA	0.0005	0.0646	0.0029	0.0364	0.0111	0.0003
Mt. Adams WA	0.0002	0.0417	0.0019	0.0344	0.0064	0.0002
Mt. Hood WA	0.0001	0.0659	0.0013	0.0117	0.0062	0.0001
Mt. Rainier NP	0.0014	0.1672	0.0064	0.0571	0.0193	0.0008
Olympic NP	0.0042	0.3060	0.0097	0.3151	0.0617	0.0014
Columbia River Gorge[b]	0.0004	0.0798	0.0027	0.0292	0.0096	0.0003
Class I Area Max. Conc.[b]	0.0042	0.3060	0.0097	0.3151	0.0617	0.0014
Class I Area PSD Increment[c]	2.5	8	4	25	5	2

a. NO_X was conservatively assumed to be 100% converted to NO_2.
b. The Columbia River Gorge National Scenic Area is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.
c. PSD = Prevention of Significant Deterioration from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v).

6.3. Nitrogen and Sulfur Deposition Impacts

CALPUFF was applied to predict the impacts of acid-forming compounds emitted by the Units 3 and 4 sources on soils, vegetation, and aquatic resources in regional Class I areas. There are no standards for evaluation of these impacts to the AQRVs in Washington and Oregon. However, the NPS has established a Deposition Analysis Threshold (DAT) for nitrogen and sulfur of 0.005 kilograms per hectare per year (kg/ha/yr).[23] This threshold is based on natural background deposition values culled from various research efforts, a variability factor, and a safety factor that accounts for cumulative effects. The nitrogen and sulfur DATs are not adverse impact thresholds, but are intended as conservative screening criteria that allow the FLMs to identify potential deposition fluxes that require their consideration on a case-by-case basis.

The results of the Units 3 and 4 source CALPUFF simulations for nitrogen and sulfur deposition are summarized in Table 16 where the maximum annual predictions for each Class I area and the CRGNSA are compared to the NPS nitrogen and sulfur DATs. General regional flow tends to direct plumes from the facility away from the Class I areas. Predicted annual deposition fluxes

[23] Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds, available on the FLAG internet site at http://www2.nature.nps.gov/ard/flagfree/NSDATGuidance.htm.

are highest within the Chehalis River valley, generally east of the Grays Harbor Energy Center site.

Table 16. Predicted Class I Area and CRGNSA Deposition Fluxes (kg/hr/yr)

Area of Interest	Maximum Annual N Deposition	Maximum Annual S Deposition
Alpine Lakes WA	0.0010	0.0007
Glacier Peak WA	0.0007	0.0005
Goat Rocks WA	0.0003	0.0003
Mt. Adams WA	0.0002	0.0001
Mt. Hood WA	0.0001	0.0001
Mt. Rainier NP	0.0010	0.0008
Olympic NP	0.0018	0.0018
Columbia River Gorge[a]	0.0010	0.0008
NPS DAT	0.005	0.005

a. The Columbia River Gorge National Scenic Area is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

The predicted maximum annual nitrogen and deposition fluxes are less than the respective NPS nitrogen and sulfur DATs in all Class I areas and the CRGNSA. Based on comparisons to these conservative screening criteria, acid-forming compounds emitted by the Units 3 and 4 sources are unlikely to significantly impact soils, vegetation, and aquatic resources in regional Class I areas.

A cumulative analysis of deposition is not required because the predicted deposition fluxes are less than the NPS nitrogen and sulfur DATs. However, at the request of the FLMs, Table 17 shows the predicted deposition rates from the proposed source emissions combined with maximum potential annual emissions from Unit 1 and 2 sources. The cumulative deposition fluxes are also less than the nitrogen and sulfur DATs.

Table 17. Predicted Class I Area and CRGNSA Deposition Fluxes Including Existing Grays Harbor Energy Center Sources (kg/ha/yr)

Area of Interest	Maximum Annual N Deposition	Maximum Annual S Deposition
Alpine Lakes WA	0.0022	0.0015
Glacier Peak WA	0.0016	0.0011
Goat Rocks WA	0.0008	0.0005
Mt. Adams WA	0.0004	0.0003
Mt. Hood WA	0.0002	0.0002
Mt. Rainier NP	0.0024	0.0017
Olympic NP	0.0042	0.0035
Columbia River Gorge[a]	0.0024	0.0017
NPS DAT	0.005	0.005

a. The Columbia River Gorge National Scenic Area is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

6.4. Visibility Analysis (Regional Haze)

Potential regional visibility impacts were assessed according to FLM guidance by calculating the daily percent change in extinction for each Class I area. The FLMs recommend in the FLAG Phase I Report that a five percent change in extinction from assumed natural background conditions be used to indicate a "just perceptible" change to a landscape. The CALPUFF modeling system was applied to predict both the extinction coefficient attributable to emissions from the Grays Harbor Energy Center and the background extinction coefficients. Two methods were used to calculate the change to the extinction coefficient:

- The current FLAG method with default aerosol background concentrations for natural conditions and adjustment factors based on hourly relative humidity. In the discussion that follows, this technique will be referred to as CALPOST Method 2.

- FLM proposed revisions to the FLAG Phase I Report using a different equation for the extinction coefficient (USFS et al. 2008).[24] The new equation considers sea salt, nitrogen dioxide, Rayleigh scattering that varies with elevation, monthly relative humidity adjustment factors, and other changes intended to refine the estimates for each Class I area. In the discussion that follows, this technique will be referred to as CALPOST Method 8.

The 10 days with the highest maximum predicted changes in 24-hour extinction in three years using CALPOST Method 2 are identified in Table 18. Table 19 lists the highest prediction in each Class I area and in the CRGNSA. The Olympic National Park is the area predicted to have the highest potential changes to background extinction due to the park's close proximity to the source. The other areas of interest are less affected, with occasional higher predictions for Class I areas in western Washington and the CRGNSA. The extinction budgets in Table 18 and Table 19 indicate sulfate aerosols followed by nitrate aerosols with high relative humidity contribute to the extinction coefficients on the worst days in Olympic National Park. Many of the higher episodes occur during the winter. For the other Class I areas, sulfate, nitrate, and elemental carbon (EC) or soot aerosols dominate the extinction budgets on the worst days.

Table 18. Ten Days With Maximum Predicted Class I Areas and CRGNSA Extinction Change Predicted With CALPOST Method 2 (1/Mm)

Class I Area and CRGNSA	Date	b_{ext}[a]			Change (%)	F(RH)	b_{ext} by Component[c]					
		Project	Bckgrnd[b]	Total			SO4	NO3	OC	EC	PMC	PMF
Olympic NP	05/08/04	2.471	17.487	19.958	14.13	4.98	1.095	1.096	0.086	0.194	0.000	0.000
Olympic NP	11/22/03	2.006	18.563	20.568	10.81	6.77	0.599	1.209	0.061	0.137	0.000	0.001
Olympic NP	11/21/03	1.682	18.433	20.115	9.12	6.56	0.428	1.052	0.062	0.138	0.000	0.001
Olympic NP	01/17/04	1.801	19.866	21.667	9.07	8.94	0.852	0.732	0.067	0.150	0.000	0.001
Olympic NP	07/22/05	1.360	16.839	18.199	8.08	3.90	0.493	0.694	0.053	0.120	0.000	0.000

[24] FLAG Phase I Report Revised Draft 6/27/2008 available at http://www.nature.nps.gov/air/Permits/flag/index.cfm.

Comment [A1]:

Class I Area and CRGNSA	Date	b_{ext}[a]			Change (%)	F(RH)	b_{ext} by Component[c]					
		Project	Bckgrnd[b]	Total			SO4	NO3	OC	EC	PMC	PMF
Olympic NP	12/18/04	1.574	19.805	21.379	7.95	8.84	0.529	0.900	0.044	0.099	0.000	0.001
Olympic NP	01/28/03	1.224	19.780	21.003	6.19	8.80	0.433	0.666	0.038	0.085	0.000	0.001
Mt. Rainier NP	10/05/03	1.059	17.503	18.562	6.05	5.01	0.342	0.593	0.038	0.085	0.000	0.001
Olympic NP	01/07/03	1.071	18.279	19.350	5.86	6.30	0.518	0.399	0.047	0.106	0.000	0.000
Olympic NP	12/17/04	1.138	19.656	20.795	5.79	8.59	0.380	0.660	0.030	0.067	0.000	0.001

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the current FLAG recommended methods with CALPOST Method 2.
b. Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity.
c. Extinction coefficient components are SO4 = sulfate; NO3 = nitrate; OC = organic carbon; EC = elemental carbon; PMC = coarse mass; PMF = fine crustal mass.

Table 19. Maximum Predicted Extinction Change by Class I Area and CRGNSA Predicted With CALPOST Method 2 (1/Mm)

Class I Area and CRGNSA	Date	b_{ext}[a]			Change (%)	F(RH)	b_{ext} by Component[c]					
		Project	Bckgrnd[b]	Total			SO4	NO3	OC	EC	PMC	PMF
Alpine Lakes WA	06/24/04	0.951	19.343	20.295	4.92	8.072	0.340	0.528	0.026	0.058	0.000	0.001
Glacier Peak WA	11/22/04	0.488	19.496	19.984	2.51	8.326	0.156	0.291	0.013	0.029	0.000	0.000
Goat Rocks WA	02/28/04	0.382	16.855	17.237	2.27	3.926	0.120	0.223	0.012	0.027	0.000	0.000
Mt. Adams WA	02/28/04	0.222	18.081	18.304	1.23	5.969	0.069	0.134	0.006	0.013	0.000	0.000
Mt. Hood WA	09/17/05	0.313	17.015	17.328	1.84	4.192	0.092	0.189	0.010	0.022	0.000	0.000
Mt. Rainier NP	10/05/03	1.059	17.503	18.562	6.05	5.005	0.342	0.593	0.038	0.085	0.000	0.001
Olympic NP	05/08/04	2.471	17.487	19.958	14.13	4.978	1.095	1.096	0.086	0.194	0.000	0.000
Columbia River Gorge[d]	09/17/05	0.637	17.027	17.663	3.74	4.211	0.190	0.387	0.018	0.041	0.000	0.000

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the current FLAG recommended methods with CALPOST Method 2.
b. Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity.
c. Extinction coefficient components are SO4 = sulfate; NO3 = nitrate; OC = organic carbon; EC = elemental carbon; PMC = coarse mass; PMF = fine crustal mass.
d. The Columbia River Gorge National Scenic Area is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

In 2008, the FLMs proposed revisions to the FLAG Phase I report that incorporate an improved method for the calculation of extinction coefficients (CALPOST Method 8). In the revisions, the FLMs also recommend a more statistically robust comparison with the five percent change in extinction criterion using the 98th percentile as opposed to the maximum prediction. Until these revisions have been adopted, they encourage applicants to apply both CALPOST Method 8 and Method 2 for Class I AQRV analyses. CALPOST Method 8 is based on an improved algorithm that is more specific to each Class I area, includes the effects of sea salt, distinguishes between small and large hygroscopic particles, varies Rayleigh scattering by elevation, and includes absorption by nitrogen dioxide. Importantly, CALPOST Method 8 uses monthly average relative humidity adjustments for the growth of hygroscopic aerosols and is less susceptible to artificial calculations of poor visibility driven by high hourly relative humidity that accompany rain and fog.

The 10 days with the highest predicted changes in 24-hour extinction in three years using CALPOST Method 8 are identified in Table 20. Table 21 lists the highest prediction in each Class I area and in the CRGNSA. Using this technique only five days in the 3-year simulations are greater than the five percent change to extinction criterion. The maximum-predicted extinction due to the Unit 3 and 4 sources and the change to background extinction are lower than with CALPOST Method 2.

Table 20. Ten Days With Maximum Predicted Class I Area and CRGNSA Extinction Change Predicted With CALPOST Method 8 (1/Mm)

		b_{ext}[a]			Delta	b_{ext} by Component[c]							F(RH)[b]		
Area[d]	Date	Project	Back-grnd[b]	Total	b_{ext} (%)	SO_4	NO_3	OC	EC	PMC	PMF	NO_2	Small	Large	Salt
olna	11/21/03	1.814	18.615	20.429	9.74	0.440	1.187	0.046	0.138	0.000	0.001	0.001	6.11	3.99	5.51
olna	11/22/03	1.586	18.615	20.202	8.52	0.417	0.980	0.046	0.137	0.000	0.001	0.006	6.11	3.99	5.51
olna	05/08/04	0.948	17.081	18.029	5.55	0.316	0.344	0.065	0.194	0.000	0.000	0.030	3.81	2.76	3.94
olna	01/17/04	0.968	18.381	19.350	5.27	0.382	0.363	0.050	0.151	0.000	0.001	0.020	5.76	3.80	5.27
olna	03/02/04	0.892	17.745	18.637	5.03	0.233	0.534	0.031	0.092	0.000	0.001	0.001	4.81	3.30	4.61
olna	12/18/04	0.925	18.558	19.483	4.98	0.274	0.511	0.033	0.099	0.000	0.001	0.007	6.02	3.95	5.46
mora	10/05/03	0.893	17.946	18.839	4.97	0.278	0.501	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	07/23/03	0.797	16.892	17.690	4.72	0.225	0.386	0.045	0.135	0.000	0.001	0.005	3.52	2.61	3.76
olna	01/28/03	0.788	18.381	19.170	4.29	0.241	0.427	0.029	0.085	0.000	0.001	0.005	5.76	3.80	5.27
olna	07/22/05	0.652	16.892	17.544	3.86	0.189	0.291	0.040	0.120	0.000	0.000	0.013	3.52	2.61	3.76

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the proposed FLAG recommended methods with CALPOST Method 8.

b. Class I area background extinction and monthly relative humidity adjustment factors are based on proposed FLAG recommendations with CALPOST Method 8. CRGNSA variables use the recommendations for Mt. Hood Wilderness.

c. Extinction coefficient components are SO4 = sulfate; NO3 = nitrate; OC = organic carbon; EC = elemental carbon; PMC = coarse mass; PMF = fine crustal mass; NO_X = nitrogen dioxide.

d. Alla = Alpine Lakes Wilderness; glpe = Glacier Peak Wilderness; goro = Goat Rocks Wilderness; moad = Mt. Adams Wilderness; moho = Mt. Hood Wilderness; olna = Olympic National Park; xcrg = CRGNSA.

Table 21. Maximum Predicted Extinction Change by Class I Area and CRGNSA Predicted With CALPOST Method 8 (1/Mm)

d	Date	b_{ext}[a]			Delta b_{ext} (%)	b_{ext} by Component[c]							F(RH)[b]		
		Project	Back-grnd[b]	Total		SO_4	NO_3	OC	EC	PMC	PMF	NO_2	Small	Large	Salt
alla	10/05/03	0.520	17.201	17.720	3.02	0.158	0.296	0.016	0.049	0.000	0.000	0.000	5.43	3.60	4.98
glpe	11/22/04	0.299	16.904	17.203	1.77	0.085	0.174	0.010	0.029	0.000	0.000	0.001	5.80	3.83	5.31
goro	10/05/03	0.327	15.791	16.118	2.07	0.103	0.181	0.011	0.032	0.000	0.000	0.000	5.22	3.49	4.83
moad	02/27/03	0.205	15.676	15.881	1.31	0.050	0.130	0.006	0.019	0.000	0.000	0.000	5.00	3.40	4.74
moho	09/26/04	0.252	15.415	15.666	1.63	0.074	0.130	0.012	0.036	0.000	0.000	0.000	3.79	2.72	3.78
mora	10/05/03	0.893	17.946	18.839	4.97	0.278	0.501	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	11/21/03	1.814	18.615	20.429	9.74	0.440	1.187	0.046	0.138	0.000	0.001	0.001	6.11	3.99	5.51
xcrg	10/02/03	0.325	16.065	16.391	2.02	0.089	0.188	0.012	0.036	0.000	0.000	0.000	4.93	3.35	4.67

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the proposed FLAG recommended methods with CALPOST Method 8.

b. Class I area background extinction and monthly relative humidity adjustment factors are based on proposed FLAG recommendations with CALPOST Method 8. CRGNSA variables use the recommendations for Mt. Hood Wilderness.

c. Extinction coefficient components are SO4 = sulfate; NO3 = nitrate; OC = organic carbon; EC = elemental carbon; PMC = coarse mass; PMF = fine crustal mass; NO_X = nitrogen dioxide.

d. Alla = Alpine Lakes Wilderness; glpe = Glacier Peak Wilderness; goro = Goat Rocks Wilderness; moad = Mt. Adams Wilderness; moho = Mt. Hood Wilderness; olna = Olympic National Park; xcrg = CRGNSA.

Table 22 shows the number of days exceeding the five percent change to extinction criterion by year, Class I area, and calculation method due to emissions from Unit 3 and 4 sources. The highest 98th percentile change to extinction of 3.6 percent predicted by CALPOST Method 8 for Olympic National Park in 2003 is less than the five percent screening criterion. Based on the current modeling simulations and methods from the 2008 proposed revisions to the FLAG Phase I report, emissions from Unit 3 and 4 sources would not significantly degrade visibility in Class I areas.

Table 22. Percentile and Number of Days With Extinction Change Greater Than 5% by Area, Year, and Calculation Method

Class I Area and CRGNSA	Year	Extinction Calculated by CALPOST Method 2		Extinction Calculated by CALPOST Method 8	
		98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext} > 5%	98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext} > 5%
Alpine Lakes WA	2003	1.56	0	1.04	0
	2004	1.95	0	1.07	0
	2005	1.14	0	0.91	0
Glacier Peak WA	2003	0.63	0	0.53	0
	2004	0.98	0	0.71	0
	2005	0.63	0	0.53	0

Class I Area and CRGNSA	Year	Extinction Calculated by CALPOST Method 2		Extinction Calculated by CALPOST Method 8	
		98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext}> 5%	98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext}> 5%
Goat Rocks WA	2003	1.22	0	0.81	0
	2004	0.92	0	0.79	0
	2005	0.97	0	0.83	0
Mt. Adams WA	2003	0.55	0	0.54	0
	2004	0.60	0	0.45	0
	2005	0.62	0	0.55	0
Mt. Hood WA	2003	0.49	0	0.43	0
	2004	0.78	0	0.54	0
	2005	0.52	0	0.44	0
Mt. Rainier NP	2003	1.93	1	1.40	0
	2004	1.84	1	1.12	0
	2005	1.69	0	1.46	0
Olympic NP	2003	4.73	6	3.60	2
	2004	3.93	4	2.78	3
	2005	3.75	1	2.69	0
Columbia River Gorge	2003	0.92	0	0.81	0
	2004	1.42	0	1.03	0
	2005	0.97	0	0.88	0

Although a cumulative visibility analysis is not required based on the analysis above, both GHE and the FLMs agreed that extinction coefficients should be calculated from simulations that included emissions from the existing Unit 1 and 2 sources. The simulations assume all four units would perform a 5-hour cold startup followed by 19 hours of operating under the highest possible load and that this case could occur for any day in three years. NOx emissions modeled were 5,392 pounds per calendar day. Under this scenario the highest maximum predicted changes in 24-hour extinction in three years using CALPOST Method 8 are identified in Table 23 for each area of interest. Table 24 shows the 98th percentile change to extinction and the number of days per year exceeding a five percent change to extinction. For cumulative Grays Harbor Energy Center sources, 44 days in three years were predicted to have a greater than five percent change to natural background extinction in the Olympic National Park. The highest yearly 98th percentile change to the 24-hour extinction coefficient was 7.5 percent. Actually visibility degradation is expected to much lower, since all four turbine units would not be permitted to startup every day over a three year period because the annual emission limit would be exceeded. It would physically impossible for a cold startup to occur every day. The National Park Service Land Manager was consulted and was appreciative of this additional information. He determined that the impacts of the Project were acceptable.

Table 23. Maximum Predicted Extinction Change Predicted With CALPOST Method 8 Including GHE Center Existing Sources (Units 1 and 2) (1/Mm)

Area [d]	Date	b_{ext} [a]			Delta b_{ext} (%)	b_{ext} by Component [c]							F(RH) [b]		
		Project	Back-grnd [b]	Total		SO4	NO3	OC	EC	PMC	PMF	NO2	Small	Large	Salt
alla	10/05/03	1.079	17.20	18.28	6.270	0.309	0.621	0.041	0.107	0.000	0.001	0.000	5.43	3.60	4.98
glpe	11/22/04	0.604	16.90	17.51	3.570	0.161	0.358	0.023	0.060	0.000	0.001	0.002	5.80	3.83	5.31
goro	10/05/03	0.682	15.79	16.47	4.320	0.206	0.378	0.027	0.070	0.000	0.001	0.000	5.22	3.49	4.83
moad	02/27/03	0.432	15.68	16.11	2.750	0.099	0.273	0.016	0.043	0.000	0.000	0.000	5.00	3.40	4.74
moho	09/26/04	0.529	15.42	15.94	3.430	0.145	0.273	0.030	0.079	0.000	0.001	0.001	3.79	2.72	3.78
mora	10/05/03	1.856	17.95	19.80	10.340	0.551	1.045	0.072	0.187	0.000	0.002	0.000	5.55	3.66	5.05
olna	11/21/03	3.783	18.62	22.40	20.320	0.883	2.469	0.119	0.307	0.000	0.003	0.002	6.11	3.99	5.51
xcrg	10/02/03	0.709	16.07	16.77	4.410	0.185	0.408	0.032	0.082	0.000	0.001	0.001	4.93	3.35	4.67

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the proposed FLAG recommended methods with CALPOST Method 8.
b. Class I area background extinction and monthly relative humidity adjustment factors are based on proposed FLAG recommendations with CALPOST Method 8. CRGNSA variables use the recommendations for Mt. Hood Wilderness.
c. Extinction coefficient components are SO4 = sulfate; NO3 = nitrate; OC = organic carbon; EC = elemental carbon; PMC = coarse mass; PMF = fine crustal mass; NO_X = nitrogen dioxide.
d. Alla = Alpine Lakes Wilderness; glpe = Glacier Peak Wilderness; goro = Goat Rocks Wilderness; moad = Mt. Adams Wilderness; moho = Mt. Hood Wilderness; olna = Olympic National Park; xcrg = CRGNSA.

Table 24. Predicted 98th Percentile and Number of Days With Extinction Change Greater Than 5% Using CALPOST Method 8 Including GHE Center Existing Sources (with Units 1 and 2)

Class I Area and CRGNSA	Year	Extinction Calculated by CALPOST Method 8	
		98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext} > 5%
Alpine Lakes WA	2003	2.17	1
	2004	2.27	0
	2005	1.94	0
Glacier Peak WA	2003	1.14	0
	2004	1.54	0
	2005	1.13	0
Goat Rocks WA	2003	1.62	0
	2004	1.66	0
	2005	1.74	0
Mt. Adams WA	2003	1.15	0
	2004	0.97	0
	2005	1.16	0
Mt. Hood WA	2003	0.92	0
	2004	1.15	0
	2005	0.95	0

Class I Area and CRGNSA	Year	Extinction Calculated by CALPOST Method 8	
Mt. Rainier NP	2003	2.91	1
	2004	2.38	1
	2005	3.12	0
Olympic NP	2003	7.45	14
	2004	5.75	15
	2005	5.58	15
Columbia River Gorge	2003	1.73	0
	2004	2.09	0
	2005	1.86	0

7. CONCLUSION

The Project will have no significant adverse impact on air quality. The Washington State Energy Facility Site Evaluation Council finds that the applicant, Grays Harbor Energy II, LLC, has satisfied all requirements for a Notice of Construction/Prevention of Significant Deterioration approval for the Grays Harbor Energy Center Units 3 and 4 Project.

For additional information, please contact:

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APPENDIX A. Additional Information on 1-Hour NO_X and SO_X Modeling

Note: EPA issued guidance on how to model the new 1-hour NOx and SOx standards on June 29, 2010 and August 23, 2010 respectively. This was very late in the processing of the GHE application. The following email discussion shows the development and implementation of the impacts analysis of the most important mode of operation for each pollutant. For 1-hour NOx, this is startup and shutdown. For 1-hour SO2, this is normal operation.

From:	Burmark, Robert (ECY)
Sent:	Thursday, September 02, 2010 4:28 PM
To:	'Eric Hansen'; 'Eric Albright'; Richmond Ken (krichmond@environcorp.com)
Cc:	Ogulei, David (ECY); Newman, Alan (ECY); 'Mark Goodin'
Subject:	GHE modeling questions for TSD
Attachments:	GHE 3&4 TSD Draft3.docx

I am working through finalizing the GHE Units 3&4 TSD and adding the new modeling info you sent in the last weeks. A couple of questions all on page 33:

1) For the 1 hr SO2, you gave the 99^{th} percentile in Eric's June 22 email. This is as agreed before the new guidance came out. The new guidance suggests a comparison of the maximum against a SIL of 3 ppb (7.85 ug/m3 I think – check me out on this). The original 99% data (6.8ug/m3) looks like it is pretty close to the SIL.
   a) Does the Max data break the SIL, and
   b) if so, what is it and are there any significant SO2 competing sources around (I have a call into Mark Goodin on this)?
   c) Do you have a suggestion for 1 hr SO2 background? Beacon Hill?
2) For Table 4.3, I can't find the Worst Case Startup 1 hr NOx impact in the info you sent me. I need to fill it in on the first line of the NOx section, and the Total impact too.

With this, I hope this TSD is ready for final proofing and public notice.

Bob Burmark
Air Quality Program
Phone: (360)407-6812
Fax: (360)407-7534
Email: rbur461@ecy.wa.gov

Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

From: Eric Hansen [mailto:ehansen@Environcorp.com]
Sent: Tuesday, September 14, 2010 1:28 PM
To: Burmark, Robert (ECY)
Subject: RE: GHE modeling questions for TSD

Responses.

1a) We took another look at the SO2 modeling and determined that SO2 emissions attributable to two combustion turbines, the boiler, and the emergency diesel generator result in a maximum 1-hour SO2 concentration of 22.45 µg/m3, which exceeds the SIL of (approximately) 8 µg/m3

1b) The only competing sources likely to have a significant effect on local concentrations are the existing two combustion turbines. Assuming Unit 1 and Unit 2 are operating at the maximum rates, the cumulative (new sources as described in 1b above plus combustion turbines 1 and 2) maximum 1-hour SO2 concentrations is predicted to be 40.76 µg/m3 and the 99th percentile daily 1-hour maximum concentration is 23.05 µg/m3.

1c) Analysis of ambient SO2 monitoring data that Duke collected at Satsop in 2002 and 2003 revealed a maximum 1-hour SO2 concentration of 16 µg/m3. Combining this maximum background value and the maximum model prediction, the resulting total SO2 concentration for Table 4.2 is 57 µg/m3. This is significantly below the 1-hour SO2 National Ambient Air Quality Standard of 196 µg/m3.

2) The preliminary draft PSD permit for units 3 and 4 includes a limit of 875 lbs NOX per startup period. The startup period is up to 5 hours in duration, so average NOx emissions would be limited to about 175 lb/hr. However, CEMS data for units 1 and 2 reveals a maximum 1-hour NOX emission rate of 234 lbs/hour. ENVIRON conservatively modeled a startup with this maximum 1-hour NOX emission rate, with the other three combustion turbines operating a maximum load. The maximum model-predicted 1-hour NO2 concentration, assuming 90% conversion of NOx to NO2 , is 87.61ug/m3. Added to the 48.92 background and the 75.3 05 µg/m3 background alternatives (from Moyie Springs and Portland, respectively) yields concentrations of 136.5 and 162.9 µg/m3 respectively. Both concentrations are less than the 188 µg/m3 standard.

From: Ken Richmond [krichmond@Environcorp.com]
Sent: Friday, September 17, 2010 3:12 PM
To: Eric Hansen; Burmark, Robert (ECY)
Cc: Clint Bowman - Ecology
Subject: RE: GHE modeling questions for TSD

Bob,

You previously asked ENVIRON to evaluate compliance with the new 1-hour NO_X ambient air quality standard during a startup scenario. We submitted results for an operating scenario where one of the new turbines was in startup model while the other three combustion turbines operated at full load. You requested that we examine the potential impacts of simultaneous startups. As a response to your request, ENVIRON has now analyzed the 1-hour NO_X impacts associated with the worst case simultaneous startup of all four combustion turbines.

The startup of combustion turbines is a complex process. NO_X emissions during startup vary considerably, generally with lower emissions towards the beginning and ending of the startup process, and higher emissions during the middle. Because the turbine startups do not begin at the same time, it is unlikely that each turbine would emit at their maximum rate during the same hour. However, to maintain a conservative analysis, ENVIRON has modeled each turbine starting up simultaneously operating at the maximum hourly emission rate seen during startup – 234lbs/hr of NO_X. Note that the preliminary draft permits under consideration limit startup emissions to an average of 175 lb/hr. Given that we are evaluating four combustion turbines in a startup mode, it might be more appropriate to apply these average values because they would not all be at the same (maximum emission) point in the startup curve simultaneously. Nonetheless, we have evaluated a NOx emission rate that is approximately 34% higher than the permit might allow. As with the previous analysis, it was assumed that one auxiliary boiler would be running during the startup periods.

Dispersion modeling for this startup analysis was performed with the same meteorological data and regulatory options as the previous analysis, but with two revisions:

1. The use of the Plume Volume Molar Ratio Method (PVMRM)
2. An additional 2000x2000m receptor grid was added surrounding the maximum impact receptor

The PVMRM model option predicts ambient NO_2 concentrations based on the chemistry of nitrogen oxides and ozone in ambient air. The PVMRM model option requires several additional user inputs. These inputs and the values used in this analysis are summarized below.

1. An in-stack ratio of NO_2 to NO_X (default is 10%)
   a. Based on prior guidance from Clint Bowman, ENVIRON assumed a 15% ratio of NO_2 to NO_X. We have several reputable sources indicating this is quite conservative. [25]
2. An equilibrium ratio (the maximum potential conversion) of NO_2 to NO_X (default is 90%)
   a. The default ratio of 90% was used based on regulatory guidance.
3. Real time background ozone data
   a. Environ obtained regional ozone data from two stations located near Mount Rainier, WA. The primary station ID is 530531010. For any missing hours at the primary station, secondary station data was taken from station ID 530530012.

[25] For NO2/NOx ratio references, see Table 1 placed at the end of this appendix.

These stations were chosen based on the rural nature of the stations and the relative completeness of the data. Further information regarding the selection of ozone stations can be provided upon request.

4. A default ozone background value to use if the hour is missing for both stations
    a. ENVIRON used the annual average ozone value seen for the data set of .022ppm. This value was used for a total of 18 hours for the 8760 hour modeling period.

Because the maximum predicted concentrations during this startup scenario are seen approximately 7 km away SW from the facility, where the receptor grid is coarse, ENVRON placed a tighter spaced (200 meter) receptor grid around the peak model concentration to more accurately predict the maximum concentration.

The maximum predicted 1-hour NO_2 concentration for the simultaneous startup of four turbines is 185 µg/m^3. The maximum predicted 98th percentile value of daily maximum concentrations is 76.6 µg/m^3. The 98th percentile is much lower because winds in the direction toward the worst case terrain elevations occur infrequently. When added to previously presented 98th percentile background values of 48.9 µg/m^3 (Idaho rural) and 75.3 µg/m^3 (Portland), this yields a cumulative concentration of 125.6 µg/m^3 and 151.9 µg/m^3 , respectively. Both of these values are under the 1-hour NO_2 National Ambient Air Quality Standard of 188 µg/m^3.

Regards,

Ken Richmond

From: Clint Bowman [mailto:clint@ecy.wa.gov]
Sent: Monday, September 20, 2010 9:19 AM
To: Ken Richmond
Cc: Eric Hansen; Bob Burmark
Subject: RE: GHE modeling questions for TSD

Ken,

Because you are using just a single year, I'd like a list (with dates and predicted concentrations) of the top two percent (max - 98th percentile--a top ten table of daily max 1-hr would work) to get a better idea of the risks involved with using the 98th percentile.

Thanks for digging into this scenario. Do make sure that you cite references in support of this analysis.

Clint

Date: Mon, 20 Sep 2010 13:07:42
From: Ken Richmond <krichmond@environcorp.com>
To: Clint Bowman <clint@ecy.wa.gov>
Cc: Eric Hansen <ehansen@environcorp.com>, Bob Burmark <rbur461@ecy.wa.gov>, swinges@environcorp.com
Subject: RE: GHE modeling questions for TSD

Clint
Here's the table of top 8 daily 1-hour max from the 4 turbine startup case:

Number	NO2 Concentration (µg/m3)	Location UTMX	UTMY	Date Hr (YYMMDDHH)
1	185.0	458643	5198218	02092204
2	127.3	464743	5199918	02092009
3	110.8	456843	5197418	02070605
4	98.3	457643	5197618	02070601
5	90.8	456843	5197418	02110321
6	89.1	456843	5197418	02092302
7	86.5	456843	5197418	03012503
8	76.6	457643	5197618	02092107

Ken

From: Ken Richmond [krichmond@Environcorp.com]
Sent: Tuesday, September 21, 2010 11:26 AM
To: Bowman, Clint (ECY)
Cc: ehansen@Environcorp.com; swinges@Environcorp.com; Burmark, Robert (ECY)
Subject: RE: GHE modeling questions for TSD (fwd)

Clint

Here's a summary of the data we used for background NO2:

- Portland 2008 the max was 103.5, 98th was 75.3 (7th hi), based on 344 days
- Portland 2009 the max was 116.7, 98th was 75.3 (7th hi), based on 346 days

We used the last two years of consecutive data. Monitoring goes back to 1990, but we wanted to use the latest in case of trends. Note:

- Portland 2007 the max was 99.7, 98th was 69.6 (5th hi), based on 235 days.
- For Moyie Springs Id, we only had 1 complete year:

- Moyie Springs 2003 the max was 54.6, 98th was 48.9 (8th hi), based on 362 days

We can provide both data sets if you would like to perform further analyses. I think we have the Portland data from 1990-2010.

Ken Richmond

From: Clint Bowman [clint@ecy.wa.gov]
Sent: Tuesday, September 21, 2010 1:57 PM
To: Ken Richmond
Cc: ehansen@environcorp.com; swinges@environcorp.com; Burmark, Robert (ECY)
Subject: RE: GHE modeling questions for TSD (fwd)
Attachments: beacon_hill_yearly_98th.txt

A quick evaluation of the Beacon Hill NO2 data for 1996 through 20100920 is attached. The long term 98th percentile is 57 ppb. I've also computed the 98th and 99th for each year. Six years failed to make a 90 percent data recovery and I've, somewhat arbitrarily, dismissed them. Eight of the remaining nine years have a 99th percentile value less than 57 ppb.

This error is almost identical to that found when comparing 1:3 monitoring with everyday monitoring and 1:3 day monitoring is accepted in determining the attainment status of an area.

This analysis shows that the 99th percentile determined by one year will be sufficiently protective of the three-year average 98th percentile that constitutes the 1-hour NO2 NAAQS.

Clint

From: Clint Bowman [clint@ecy.wa.gov]
Sent: Tuesday, September 21, 2010 4:12 PM
To: Ken Richmond
Cc: Eric Hansen; Scott Winges; Burmark, Robert (ECY)
Subject: RE: GHE modeling questions for TSD (fwd)

Ken,

The annual NO2 figure interpolated for Washington implies that the Portland data is likely to be most representative for Satsop. Bob and I are going to recommend that you use Portland based on that observation (if the annual is similar, we hypothesize that the 1-hr will be similar.)

So, use the three-year average 98th percentile from Portland for the background and the modeled 99th percentile which I've shown is likely to be protective of the long-term 98th which is used to define the NAAQS.

(I'm basing my assumption on analysis of modeling and observations of daily PM2.5 concentrations which show that AERMOD seems to behave similarly to observations at the extreme values of the 98th percentile. I believe that model behavior will also be similar to observations for the daily high 1-hr NO2).

So we have 75.3 + 98.3 which equals 173.6 ug/m3 which is less than 188 ug/m3. So Class 2 analysis will allow four cold starts to occur simultaneously.

Clint

<table>
<tr><th colspan="4">Table 1: Recommend In-stack NO2/NOx Ratios</th></tr>
<tr><th>Refer #</th><th>Equipment Category (Controls)</th><th>Range of NO_2/NOx Ratios (%)</th><th>Recommended NO_2/NOx Ratio (%)</th></tr>
<tr><td>
1
2</td><td>Boilers - NG
Default
7.6 MMBtu/Hr (SCR / FGR)*</td><td>
10
3.45 – 15.79</td><td>
10
9.65**</td></tr>
<tr><td>3</td><td>Turbines - NG</td><td>8.33 – 9.1</td><td>9.1</td></tr>
<tr><td>1</td><td>Compressors - NG</td><td>60</td><td>60</td></tr>
<tr><td>2</td><td>Glass Furnace</td><td>2.45 – 11.59</td><td>4.32**</td></tr>
<tr><td>1</td><td>IC Engines - Diesel</td><td>20</td><td>20</td></tr>
<tr><td>
4
2
2</td><td>IC Engine - NG
Lean Burn
2,775 BHP (SCR)*
4,175 BHP (SCR,CO & VOC CATALYSTS)*</td><td>
5-10
14.53 – 26.33
0.0 – 21.28</td><td>
10
19.46**
1.15**</td></tr>
<tr><td>5</td><td>Transportation Refrigeration Units (TRUs)

CARB= CARB Diesel
GTL = Gas To Liquid</td><td colspan="2">
<table>
<tr><th>Fuel</th><th>Eng Speed</th><th>Exhaust</th><th>NO_2/ NO_x Ratio</th></tr>
<tr><td>CARB</td><td>High</td><td>Muffler</td><td>15.37</td></tr>
<tr><td>GTL</td><td>High</td><td>Muffler</td><td>16.17</td></tr>
<tr><td>CARB</td><td>High</td><td>pDPF</td><td>25.71</td></tr>
<tr><td>CARB</td><td>Low</td><td>Muffler</td><td>22.66</td></tr>
<tr><td>GTL</td><td>Low</td><td>Muffler</td><td>25.12</td></tr>
<tr><td>CARB</td><td>Low</td><td>pDPF</td><td>12.98</td></tr>
</table>
</td></tr>
<tr><td>6</td><td>Truck / Cars
Light / Medium Duty (Gas/Diesel)
Heavy Duty</td><td>
16-25
6-11</td><td>
25
11</td></tr>
</table>

* Samples taken each minute or several minutes
**Value represents the statistical average of all data points

References

1. Barrie Lawrence, Environmental Scientist, Government of Newfoundland and Labrador, "Guideline for Plume Dispersion Modeling" 1st Revision: November 20, 2006, Page 14
2. District Database "NO2 -NOx Ratio.mdb" - Data is based on CEMs, source test, and portable analyzer data collected in the San Joaquin Valley
3. Roointon Pavri and Gerald D. Moore, GE Energy Services Atlanta, GA, "Gas Turbine Emissions and Control" March 2001 Page 63
4. Nigel N. Clark, Center for Alternative Fuels, Engines and Emissions Department of Mechanical and Aerospace Engineering West Virginia University Morgantown, WV 26506, "Selective NOx Recirculation for Stationary Lean-Burn Natural Gas Engines" April 30, 2007 Page 64
5. Robb A. Barnitt, National Renewable Energy Laboratory, "Emissions of Transport Refrigeration Units with CARB Diesel, Gas-to-Liquid Diesel, and Emissions Control Devices", May 1, 2010
6. P G Boulter, I S McCrae, and J Green, Transportation research Laboratory, "Primary NIO2 Emissions From Road Vehicles in the Hatfield and Bell Commons Tunnels", July 2007

Note: Table 1 is an update to "Assessment of Non-Regulatory Option in AERMOD Appendix C" by the San Joaquin Unified Air Pollution Control District available at http://www.valleyair.org/busind/pto/Tox_Resources/AirQualityMonitoring.htm