5.0 PERMIT APPLICATIONS

SECTION 5.1 AIR EMISSIONS PERMITS AND AUTHORIZATIONS (WAC 463-60-536)

5.1.1 INTRODUCTION

Grays Harbor Energy LLC proposes 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, doubling the project's generating capacity to 1,300 MW.

Certain facilities installed for the Grays Harbor Energy Center, such as the Administration Building (including control room), gas regulation and treatment, and the water treatment building also will serve Units 3 and 4, and new facilities of this type are not required.

The Energy Facility Site Evaluation Council (EFSEC) is the lead state agency responsible for environmental permitting of energy facilities with a capacity of greater than 350 MW. EFSEC has responsibility for technical review of air quality concerns and for administering the Prevention of Significant Deterioration (PSD) program, however, review is conducted by assigned staff at the Washington Department of Ecology (Ecology). The United States Environmental Protection Agency (USEPA) co-signs the PSD permit.

Under Washington Administrative Code (WAC) 463-78-005, EFSEC has adopted by reference the general air quality regulations Ecology has established in Chapters 173-400, 173-401, 173-406, and 173-460 WAC. Although authority is delegated to EFSEC, this section cites the Ecology regulations to provide specific reference to the PSD permit requirement. It should also be noted that regulations established by the Olympic Region Clean Air Agency (ORCAA) do not, strictly speaking, apply to Units 3 and 4. However, ORCAA regulations are noted in the discussion of applicable regulations.

5.1.1.1 Organization

Section 5.1 constitutes a combined Notice of Construction (NOC) and PSD permit application. A PSD permit addresses criteria pollutants emitted in significant quantities (defined in the federal PSD program). The NOC permit addresses toxic air pollutants (TAPs) defined in WAC 173-460 and other criteria pollutants emitted in quantities below the PSD significance levels.

Key components of the PSD permit application are as follows:

- An air quality permit application typically begins with a project description. However, this permit application is a component of a broader Application for Site Certification (Application). Section 2.3 (Construction on Site) of the Application provides a project description.

- Section 5.1.2 identifies applicable air quality regulation and summarizes anticipated emissions based upon the Best Available Control Technology (BACT) analyses. The BACT analysis and emission calculations are detailed in Appendix A-1 and Appendix A-2, respectively.

- Section 5.1.3 describes the local air quality impact analysis used to estimate concentrations of criteria pollutants and TAPs in the vicinity of the project (i.e., Class II areas), presents predicted concentrations calculated using dispersion models, and compares the results with regulatory criteria.

- Section 5.1.4 addresses the effect of emissions from Units 3 and 4 on regional air quality related values, including visibility and acid deposition in national parks and wilderness areas (i.e. Class I areas). Section 5.1.4 also includes a discussion of the cumulative impact of all four combustion turbine generators.

- Section 5.1.5 addresses additional impacts related to growth.

- References are provided in Section 1.5 (Sources of Information) of this Application.

5.1.1.2 Summary of Findings

The air quality impact assessments that follow indicate:

- Predicted maximum concentrations of criteria pollutants attributable to emissions from Units 3 and 4 are less than the Significant Impact Levels (SILs) established by USEPA and Ecology. The SILs represent incremental, project-specific impact levels that USEPA and Washington accept as indication that project impacts are insignificant with respect to maintaining compliance with ambient air quality standards established to protect human health and welfare.

- Predicted concentrations of all TAPs attributable to the addition of Units 3 and 4 to the Grays Harbor Energy Center are either below Ecology's Small Quantity Emissions Rates (SQERs) or, as demonstrated by an air quality dispersion modeling analysis, Ecology's Acceptable Source Impact Levels (ASILs).

- The CALPUFF modeling system was used to predict concentrations of NO_X, SO_2, and PM_{10} in regional Class I areas and the Columbia River Gorge National Scenic Area (CRGNSA) using a three year regional meteorological data set. CALPUFF simulations indicate criteria pollutant concentrations attributable to Unit 3, Unit 4 and associated sources are less than the Class I Significant Impact Levels and PSD increments in all Class I areas and the CRGNSA.

- CALPUFF was applied to predict the impacts of emissions from Units 3 and 4 on soils, vegetation and aquatic resources in regional Class I areas. The predicted maximum sulfur and nitrogen deposition fluxes are less than the thresholds of concern established by the National Park Service in all Class I areas and the CRGNSA. Based on comparisons to these conservative screening criteria, acid-forming compounds

emitted by Units 3 and 4 sources are unlikely to significantly impact soils, vegetation and aquatic resources in regional Class I areas.

- Potential regional visibility impacts were assessed by calculating the daily percent change in light extinction for each Class I area. A five percent change in extinction from assumed natural background conditions is used to indicate a "just perceptible" change to a landscape. Using the most recent methodology recommended by the Federal Land Managers (FLMs), the change to extinction criterion of five percent is predicted to be exceeded at one receptor in Olympic National Park on two days out of the three simulated years. Using an older, less robust, methodology, the change to extinction criterion was predicted to be exceeded at one receptor in Olympic National Park on six days over three years, also. Project emissions would have an imperceptible effect on visibility in other Class I areas and the CRGNSA.

- At the request of the FLMs, cumulative simulations including existing Units 1 and 2, as well as proposed Units 3 and 4 were developed to predict concentrations, impacts to vegetation and aquatic resources, and regional visibility impacts in the same Class I areas using the same modeling methodology and meteorological dataset.

5.1.2 EMISSIONS

In order to determine the potential air quality impacts associated with a proposed industrial facility and the regulations that would apply to the facility, the types and quantities of emitted air pollutants must be identified. Pollutant emissions are determined by the physical and operational characteristics of the facility. Part 2 of the Application for Site Certification provides a detailed physical description of Units 3 and 4. The following section describes how the facility will operate, and how the emissions are derived for the air quality analyses.

Detailed supporting emission calculations are presented in spreadsheets provided in Appendix A-2.

5.1.2.1 Normal Operation and Short-term Emission Rates

Power Generation Units

The two proposed combustion turbine generators (CTGs) would combust only natural gas. The hot exhaust gases exiting the combustor flow to the expander turbine, which drives the generator to produce electricity and also turns the air compressor section of the combustion turbine. Hot exhaust gas from the expander is ducted through the heat recovery steam generator (HRSG) to generate high-energy steam that is used to produce additional electricity in the steam turbine generator (STG). Steam generation in the HRSG may be supplemented using duct burners. Following heat recovery, the cooled CTG exhaust gas is discharged to the atmosphere through the HRSG stacks. Selective catalytic reduction (SCR) control equipment for removal of oxides of nitrogen (NO_x) emissions and an oxidation catalyst (for control of carbon monoxide (CO) and volatile organic compounds (VOCs) would be located within the HRSG. The CTG units and the HRSGs would always operate together. The CTGs would only operate in simple-cycle mode for short durations if the steam turbine tripped or became unavailable.

Units 3 and 4 would have a total of three sources of power generation: two CTGs and one STG. Combined, the CTGs and STG would generate approximately 650 MW gross. Duct burners in the HRSGs would contribute up to 60 MW each of the 650 MW total.

Combustion turbines identified for this facility are General Electric model GE 7FA, similar to those currently in operation at the Grays Harbor Energy Center. There are two potential generations of this model that could be used, an original model and a newer, slightly more energy-efficient model with higher capacity (i.e., uprated). Emissions from both the original and new versions were modeled for all operating scenarios, and the worst-case results are presented. Regardless of which turbines are eventually selected, the combustion turbines will meet the same proposed continuous operation emission limits for each criteria pollutant (e.g., 2 ppmvd NO_x at 15 percent O_2) between 60 percent load and 100 percent load. Turbine operation may be supplemented by combustion with duct burners in the HRSG. The minimum load expected for the units during standard operations is 60 percent. To evaluate air quality implications of the range of operating conditions, we examine four potential operating modes:

1) 100 percent combustion turbine load with duct burners
2) 100 percent combustion turbine load without duct burners
3) 60 percent combustion turbine load without duct burners
4) Combustion turbine startup/shutdown

Table 5.1-1 presents short-term emission rates for each combustion turbine operating mode; here, as elsewhere in this application, the averaging periods we consider correspond to the averaging period applied to that pollutant's ambient standard. Although operation with duct burners typically produces the highest overall facility emissions, the modeling analyses considered all four scenarios because predicted ground level concentrations are affected by exhaust gas characteristics (flow rate and temperature) as well as emission rates.

TABLE 5.1-1
CRITERIA POLLUTANT EMISSIONS FROM BOTH POWER GENERATION UNITS

Operating Mode	NO_x	CO	SO_2[a]		PM_{10}	$PM_{2.5}$[b]	VOC
			1 and 3-hr	24-hr			
100% load with duct firing	40.0	24.4	28.3	26.1	38.0	9.50	6.96
100% load, without duct firing	31.7	19.3	21.9	20.2	38.0	9.50	5.52
60% load	22.5	13.7	15.6	14.4	38.0	9.50	11.8
Maximum	40.0	24.4	28.3	26.1	38.0	9.50	11.8

Pounds per hour for the Units 3 and 4 combustion turbine/HRSG power units, combined. Emission rates were calculated based on emission factors and exhaust gas conditions provided the by the CTG vendor (GE). NO_X, CO, and VOC emission factors are based on BACT, SO_2 is based on measurements of sulfur in the pipeline natural gas, and PM_{10} is based on information from the CTG vendor (GE).

a. Based on the maximum sulfur content of natural gas over the following averaging periods, in grains per 100 standard cubic feet: 2.07 for 1 and 3-hour, and 1.91 for 24-hour.

b. Filterable $PM_{2.5}$ emissions are assumed to be 25% of PM_{10} emissions based on the fraction provided in AP-42 Section 1.4. Total $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions

In addition to the type of turbine, the ambient air temperature also affects the emissions. Three temperatures were chosen to evaluate the full range of expected operating conditions: a low

temperature of 20ºF, the rated temperature of 59ºF, and a high temperature of 90ºF. Emissions were consistently highest with an assumption of an ambient air temperature of 20ºF.

NO_x and CO emissions are based on proposed emission limits of 2 parts per million by volume, dry (ppmvd) at 15 percent O_2, 3-hour and 1-hour averages, respectively.

Units 3 and 4 have estimated SO_2 emissions based on mass balance calculations using the concentration of sulfur in the natural gas passing through the Williams Northwest Pipeline Sumas station. The analysis for Units 3 and 4 used a sulfur content for the natural gas of 24-hour, 3-hour, and 1-hour levels of 2.13, 2.34, and 2.36 grains/100cf based on the 99th percentile of these time-period levels as measured in the Williams natural gas supply at Sumas, Washington from the 4th quarter of 2007 through the 3rd quarter of 2008. The annual average sulfur content during this period was 1.07 grains/100cf. The natural gas heating value used to calculate emissions is 1,024 Btu per cubic foot.

Particulate matter (PM) and VOC emissions are based on GE data. The PM emission rate includes a sulfate that results from oxidation of sulfur in the natural gas.[1] Air quality dispersion modeling analyses were developed for both filterable $PM_{2.5}$ and total $PM_{2.5}$. Guidance received from USEPA Region 10 on August 25, 2008 indicates that only filterable $PM_{2.5}$ should be evaluated, but Ecology requested an analysis of total $PM_{2.5}$ for informational purposes.

Units 3 and 4 also have the potential to emit non-criteria air pollutants that are regulated at the federal level by the CAA Section 112 and at the state level by Ecology and EFSEC under Chapter 173-460 WAC. Some of these pollutants are deemed "hazardous air pollutants" (HAPs) under the CAA Section 112; others are defined as TAPs under Chapter 173-460 WAC.

Table 5.1-2 identifies TAPs expected to be emitted by the combustion turbines based on emission factors from Section 3.1 of USEPA's AP-42 emission factor document (Stationary Gas Turbines). Emission factors in Section 1.4 (Natural Gas Combustion) of AP-42 were used to estimate duct burner TAP and HAP emission rates. Ammonia slip emissions are based on a proposed permit limit of 5 ppmvd at 15 percent O_2. Sulfuric acid (H_2SO_4) emissions were based on an assumed 33 percent conversion of SO_2. Table 5.1-2 presents the maximum total TAP and HAP emissions from both combustion turbines under full load operation with duct burning. This represents the worst-case scenario for TAP and HAP emissions because these emissions are directly linked to fuel consumption, and the most fuel is consumed during operation at 100 percent load plus duct firing. For the worst-case assessment of TAP and HAP emissions, it is assumed that the facility would operate at 100 percent load plus duct firing continuously through the year.

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[1] However, the SO_2 emission rate was not reduced by 33 percent to account for this conversion; the analysis is conservative in that it effectively "double counts" some emitted sulfur.

TABLE 5.1-2
TAP AND HAP EMISSIONS FROM BOTH COMBUSTION TURBINES, COMBINED

Compound	CAS #	Emission Factors		Maximum Emission Rate	
		CTs	Duct Burners		
		(lb/MMBtu)	(lb/MMscf)	(lb/hr)	(ton/yr)
Acenaphthene	83-32-9	--	0.0000018	0.00000195	0.00000856
Acenaphthylene	208-96-8	--	0.0000018	0.00000195	0.00000856
Acetaldehyde	75-07-0	0.00004	--	0.152	0.664
Acrolein	107-02-8	0.0000064	--	0.0242	0.106
Ammonia	7664-41-7	0.009759178	--	37	162
Anthracene	120-12-7	--	0.0000024	0.00000261	0.0000114
Arsenic	7440-38-2	--	0.0002	0.000217	0.000951
Barium	7440-39-3	--	0.0044	0.00478	0.0209
Benzene	71-43-2	0.000012	0.0021	0.00000195	0.00000856
Benzo(a)anthracene	56-55-3	--	0.0000018	0.0477	0.209
Benzo(a)pyrene	50-32-8	0.0000022	0.0000012	0.00834	0.0365
Benzo(b)fluoranthene	205-99-2	--	0.0000018	0.00000195	0.00000856
Benzo(g,h,i)perylene	191-24-2	--	0.0000012	0.0000013	0.00000571
Benzo(k)fluoranthene	207-08-9	--	0.0000018	0.00000195	0.00000856
Beryllium	7440-41-7	--	0.000012	0.000013	0.0000571
1,3-Butadiene	106-99-0	0.00000043	--	0.00163	0.00713
Butane	106-97-8	--	2.1	2.28	9.99
Cadmium	7440-43-9	--	0.0011	0.00119	0.00523
Carbon Monoxide[a]	630-08-0	--	--	24.4	107
Chromium, (hexavalent)	18540-29-9	--	0.000056	0.0000608	0.000266
Chromium, total	7440-47-3	--	0.0014	0.00152	0.00666
Chrysene	218-01-9	--	0.0000018	0.00000195	0.00000856
Cobalt	7440-48-4	--	0.000084	0.0000912	0.0004
Copper	7440-50-8	--	0.00085	0.000923	0.00404
Dibenzo(a,h)anthracene	53-70-3	--	0.0000012	0.0000013	0.00000571
Dichlorobenzene	106-46-7	--	0.0012	0.0013	0.00571
7,12-Dimethylbenzo(a)anthracene	57-97-6	--	0.000016	0.0000174	0.0000761
Ethane	74-84-0	--	3.1	3.37	14.7
Ethylbenzene	100-41-4	0.000032	--	0.121	0.531
Fluoranthene	206-44-0	--	0.000003	0.00000326	0.0000143
Fluorene	86-73-7	--	0.0000028	0.00000304	0.0000133
Formaldehyde[b]	50-00-0	0.0001065	0.075	0.485	2.12
Hexane	110-54-3	--	1.8	1.95	8.56
Indeno(1,2,3-cd)pyrene	193-39-5	--	0.0000018	0.00000195	0.00000856
Manganese	7439-96-5	--	0.00038	0.000413	0.00181
Mercury	7439-97-6	--	0.00026	0.000282	0.00124
3-Methylchloranthrene	56-49-5	--	0.0000018	0.00000195	0.00000856
2-Methylnaphthalene	91-57-6	--	0.000024	0.0000261	0.000114
Molybdenum	7439-98-7	--	0.0011	0.00119	0.00523
Naphthalene	91-20-3	0.0000013	0.00061	0.00559	0.0245
Nickel	7440-02-0	--	0.0021	0.00228	0.00999
Nitrogen Dioxide[a]	10102-44-0	--	--	40	175
Pentane	109-66-0	--	2.6	2.82	12.4
Phenanathrene	85-01-8	--	0.000017	0.0000185	0.0000809
POM	POM	0.0000022	0.0006724	0.00906	0.0397

Compound	CAS #	Emission Factors		Maximum Emission Rate	
		CTs (lb/MMBtu)	Duct Burners (lb/MMscf)	(lb/hr)	(ton/yr)
Propane	74-98-6	--	1.6	1.74	7.61
Propylene Oxide	75-56-9	0.000029	--	0.11	0.481
Pyrene	129-00-0	--	0.000005	0.00000543	0.0000238
Selenium	7784-49-2	--	0.000024	0.0000261	0.000114
Sulfur Dioxide[a]	7446-09-5	--	--	28.3	62.8
Sulfuric acid[c]	7664-93-9	--	--	14.4	63.3
Toluene	108-88-3	0.00013	0.0034	0.496	2.17
Vanadium	7440-62-2	--	0.0023	0.0025	0.0109
Xylenes	1330-20-7	0.000064	--	0.242	1.06

a. For the TAPs analysis, CO, NO_X, and SO_2 emission rates are the worst-case emission rates for the corresponding criteria pollutants.
b. The formaldehyde emission factors were reduced by 85% to reflect control provided by the oxidation catalyst – see page 7, AP-42 Section 3.1.
c. One third of SO_2 emissions were assumed to be converted to sulfuric acid based on NPS guidance for speciation of emissions from natural gas-fired turbines (http://www.nature.nps.gov/air/Permits/ect/ectGasFiredCT.cfm).

Auxiliary Boiler

The auxiliary boiler will combust only natural gas and will be used to generate steam to assist with startup of the steam turbine. The steam from the auxiliary boiler reduces the duration of the startup period for the steam turbine and reduces thermal stresses on the steam turbine. Although the boiler is unlikely to operate concurrent with normal combustion turbine operations, the short-term continuous operation modeling scenarios include boiler emissions for the entire averaging period. Criteria pollutant emissions summarized in Table 5.1-3 are based on the use of ultra-low-NO_x burners to achieve 9 ppmvd NO_x at 3 percent O_2 and good combustion control to achieve 50 ppmvd CO at 3 percent O_2. SO_2 emissions are based on a mass balance calculation similar to that discussed for the combustion turbines. PM_{10} and VOC emissions are based on factors from Section 1.4 of AP-42.

TABLE 5.1-3
CRITERIA POLLUTANT EMISSIONS FROM AUXILIARY BOILER

		NO_x	CO	SO_2			PM_{10}[c]	VOC
				1 and 3-hr[a]	24-hr[a]	Annual[b]		
Emission Factor (lb/MMBtu)[d]		0.011	0.037	0.0058	0.0053	0.0029	0.005	0.004
Emission Rate	Short-term (lb/hr)	0.322	1.08	0.169	0.156	--	0.147	0.117
	Annual (ton/yr)[e]	0.403	1.36	--	--	0.106	0.183	0.147

a. Based on the maximum sulfur content of natural gas in grains per 100 standard cubic feet: 2.07 for 1 and 3-hour, and 1.91 for 24-hour
b. Based on annual average sulfur content of natural gas (1.04 grains per 100scf)
c. Filterable $PM_{2.5}$ emissions are assumed to be 25% of PM_{10} emissions based on the fraction provided in AP-42 Section 1.4. Total $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.
d. Natural gas heating value used to calculate these emissions is 1024 Btu/cf
e. Annual emissions based on 2,500 hours of operation per year

Auxiliary boiler TAP emissions were calculated based on natural gas-fired boiler emission factors from Section 1.4 of AP-42 and the maximum rated capacity of the boiler (assumed to be 29.3 million British thermal units per hour [MMBtu/hr]). Maximum annual emissions were based on an annual capacity factor of 2,500 hours per year. Table 5.1-4 presents the TAP and HAP emissions for the auxiliary boiler.

TABLE 5.1-4
TAP AND HAP EMISSIONS FROM AUXILIARY BOILER

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Short-term Emission Rate[a] (lb/hr)	Annual Emission Rate (ton/yr)
Acenaphthene	83-32-9	0.0000018	5.15E-08	6.44E-08
Acenaphthylene	208-96-8	0.0000018	5.15E-08	6.44E-08
Anthracene	120-12-7	0.0000024	6.87E-08	8.58E-08
Arsenic	7440-38-2	0.0002	5.72E-06	7.15E-06
Barium	7440-39-3	0.0044	1.26E-04	1.57E-04
Benzene	71-43-2	0.0021	6.01E-05	7.51E-05
Benzo(a)anthracene	56-55-3	0.0000018	5.15E-08	6.44E-08
Benzo(a)pyrene	50-32-8	0.0000012	3.43E-08	4.29E-08
Benzo(b)fluoranthene	205-99-2	0.0000018	5.15E-08	6.44E-08
Benzo(g,h,i)perylene	191-24-2	0.0000012	3.43E-08	4.29E-08
Benzo(k)fluoranthene	207-08-9	0.0000018	5.15E-08	6.44E-08
Beryllium	7440-41-7	0.000012	3.43E-07	4.29E-07
Butane	106-97-8	2.1	6.01E-02	7.51E-02
Cadmium	7440-43-9	0.0011	3.15E-05	3.93E-05
Carbon Monoxide	630-08-0	0.037	1.08E+00	1.36E+00
Chromium III	7440-47-3	0.0014	4.01E-05	5.01E-05
Chromium VI	18540-29-9	0.000056	1.60E-06	2.00E-06
Chrysene	218-01-9	0.0000018	5.15E-08	6.44E-08
Cobalt	7440-48-4	0.000084	2.40E-06	3.00E-06
Copper	7440-50-8	0.00085	2.43E-05	3.04E-05
Dibenzo(a,h)anthracene	53-70-3	0.0000012	3.43E-08	4.29E-08
1,4-Dichlorobenzene	106-46-7	0.0012	3.43E-05	3.76E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	0.000016	4.58E-07	5.72E-07
Ethane	74-84-0	3.1	8.87E-02	9.71E-02
Fluoranthene	206-44-0	0.000003	8.58E-08	1.07E-07
Fluorene	86-73-7	0.0000028	8.01E-08	1.00E-07
Formaldehyde	50-00-0	0.075	2.15E-03	2.68E-03
Hexane	110-54-3	1.8	5.15E-02	6.44E-02
Indeno(1,2,3-cd)pyrene	193-39-5	0.0000018	5.15E-08	6.44E-08
Manganese	7439-96-5	0.00038	1.09E-05	1.36E-05
Mercury	7439-97-6	0.00026	7.44E-06	9.30E-06
3-Methylcholanthrene	56-49-5	0.0000018	5.15E-08	6.44E-08
2-Methylnaphthalene	91-57-6	0.000024	6.87E-07	8.58E-07
Molybdenum	7439-98-7	0.0011	3.15E-05	3.93E-05
Naphthalene	91-20-3	0.00061	1.75E-05	2.18E-05
Nickel	7440-02-0	0.0021	6.01E-05	7.51E-05
Nitrogen Dioxide	10102-44-0	0.011	3.22E-01	4.03E-01
Pentane	109-66-0	2.6	7.44E-02	9.30E-02
Phenanthrene	85-01-8	0.000017	4.86E-07	6.08E-07

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Short-term Emission Rate[a] (lb/hr)	Annual Emission Rate (ton/yr)
Polycyclic Organic Matter	POM	0.0000882	2.52E-06	3.15E-06
Propane	74-98-6	1.6	4.58E-02	5.01E-02
Pyrene	129-00-0	0.000005	1.43E-07	1.79E-07
Selenium	7784-49-2	0.000024	6.87E-07	8.58E-07
Sulfur Dioxide	7446-09-5	0.005775354	1.69E-01	2.12E-01
Toluene	108-88-3	0.0034	9.73E-05	1.22E-04
Vanadium	7440-62-2	0.0023	6.58E-05	8.23E-05
Zinc	7440-66-6	0.029	8.30E-04	9.09E-04

a. Short-term emissions based on continuous, full load operation. Annual emission based on a maximum annual operation of 2,500 hours.

Emergency Diesel Engines

Diesel-fueled engines will be used to provide emergency power and pressurized water for fire protection during a power outage. The emergency generator was assumed to have an electrical capacity of 400 kilowatts and an engine power capacity of approximately 600 horsepower (hp). The firewater pump was assumed to be powered by a 275 hp engine. The engines will meet the emission standards prescribed by 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). Ordinarily, the engines will operate only for testing, and Subpart IIII limits non-emergency operation to 100 hours per year.

In the modeling analyses, it is assumed that the engines are tested in the one hour scenario but operate only one hour in the 3-hour, 8-hour, and 24-operating scenarios. Annual emissions are estimated based on 26 hours of operation over the course of a year, for each engine. Hourly and annual criteria pollutant emissions are presented in Table 5.1-5.

TABLE 5.1-5
CRITERIA POLLUTANT EMISSIONS FROM EMERGENCY DIESEL ENGINES

	NO_x[c]	CO	SO_2[d]	PM_{10}	$PM_{2.5}$[e]	VOC[c]
Emergency Generator						
lb/hp-hr[a]	0.0066	0.0058	0.000012	0.00033	0.00027	0.0066
lb/hr	3.95	3.45	0.00728	0.197	0.165	3.95
ton/yr[b]	0.051	0.045	0.000095	0.0026	0.0021	0.051
Firewater Pump Engine						
lb/hp-hr[a]	0.0049	0.0043	0.000012	0.00066	0.00055	0.00493
lb/hr	1.36	1.18	0.00334	0.181	0.151	1.357
ton/yr[b]	0.018	0.015	0.000043	0.0024	0.0020	0.0018

a. Emission factors based on 40 CFR Part 60 Subpart IIII, Table 4 (except SO2, see note c)
b. Annual emissions based on 26 hours of generator testing/maintenance.
c. Conservatively assumed both NO_X and VOC emissions equal the Subpart IIII limit on the sum of NO_X and VOC.
d. SO2 based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.015% by weight (8.09e-3 × %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 to be 25% of PM_{10} emissions, and total $PM_{2.5}$ emissions were assumed to be equal to PM_{10} emissions.

The emergency diesel engines TAP and HAP emission rates presented in Table 5.1-6 were calculated based on the emission standards in Subpart IIII. Maximum annual emissions were based on 26 hours per year of non-emergency operation for periodic testing.

TABLE 5.1-6
TAP AND HAP EMISSIONS FROM EMERGENCY DIESEL ENGINES

Compound	CAS #	Emission Factor (lb/MMBtu)[a]	Emergency Generator		Firewater Pump Engine	
			Short-term (lb/hr)	Annual[b] (ton/yr)	Short-term (lb/hr)	Annual[b] (ton/yr)
Acenaphthene	83-32-9	0.00000142	2.17E-06	2.82E-08	9.93E-07	1.29E-08
Acenaphthylene	208-96-8	0.00000506	7.72E-06	1.00E-07	3.54E-06	4.60E-08
Acetaldehyde	75-07-0	0.000767	1.17E-03	1.52E-05	5.37E-04	6.98E-06
Acrolein	107-02-8	0.0000925	1.41E-04	1.84E-06	6.47E-05	8.41E-07
Anthracene	120-12-7	0.00000187	2.85E-06	3.71E-08	1.31E-06	1.70E-08
Benzene	71-43-2	0.000933	1.42E-03	1.85E-05	6.53E-04	8.49E-06
Benzo(a)anthracene	56-55-3	0.00000168	2.56E-06	3.33E-08	1.18E-06	1.53E-08
Benzo(a)pyrene	50-32-8	0.000000188	2.87E-07	3.73E-09	1.32E-07	1.71E-09
Benzo(b)fluoranthene	205-99-2	9.91E-08	1.51E-07	1.97E-09	6.93E-08	9.01E-10
Benzo(g,h,i)perylene	191-24-2	0.000000489	7.46E-07	9.70E-09	3.42E-07	4.45E-09
Benzo(k)fluoranthene	207-08-9	0.000000155	2.37E-07	3.08E-09	1.08E-07	1.41E-09
1,3-Butadiene	106-99-0	0.0000391	5.97E-05	7.76E-07	2.74E-05	3.56E-07
Carbon Monoxide[c]	630-08-0	0.004276316	3.45E+00	4.49E-02	1.18E+00	1.53E-02
Chrysene	218-01-9	0.000000353	5.39E-07	7.00E-09	2.47E-07	3.21E-09
Dibenzo(a,h)anthracene	53-70-3	0.000000583	8.90E-07	1.16E-08	4.08E-07	5.30E-09
Diesel Engine Particulate[c]	DEP	0.000657895	1.97E-01	2.57E-03	1.81E-01	2.35E-03
Fluoranthene	206-44-0	0.00000761	1.16E-05	1.51E-07	5.32E-06	6.92E-08
Fluorene	86-73-7	0.0000292	4.46E-05	5.79E-07	2.04E-05	2.66E-07
Formaldehyde	50-00-0	0.00118	1.80E-03	2.34E-05	8.26E-04	1.07E-05
Indeno(1,2,3-cd)pyrene	193-39-5	0.000000375	5.72E-07	7.44E-09	2.62E-07	3.41E-09
Naphthalene	91-20-3	0.0000848	1.29E-04	1.68E-06	5.93E-05	7.71E-07
Nitrogen Dioxide[c]	10102-44-0	0.004934211	3.95E+00	5.13E-02	1.36E+00	1.76E-02
Phenanthrene	85-01-8	0.0000294	4.49E-05	5.83E-07	2.06E-05	2.67E-07
Polycyclic Organic Matter	POM	8.32621E-05	1.27E-04	1.65E-06	5.83E-05	7.57E-07
Propylene	115-07-1	0.000258	3.94E-04	5.12E-06	1.80E-04	2.35E-06
Pyrene	129-00-0	0.00000478	7.30E-06	9.48E-08	3.34E-06	4.35E-08
Sulfur Dioxide[c]	7446-09-5	0.000012135	7.28E-03	9.46E-05	3.34E-03	4.34E-05
Toluene	108-88-3	0.000409	6.24E-04	8.11E-06	2.86E-04	3.72E-06
Xylenes	1330-20-7	0.000285	4.35E-04	5.65E-06	1.99E-04	2.59E-06

a. Emission factors from USEPA AP-42 Section 3.3 Small Diesel Engines (≤600hp)
b. Maximum annual emission based on 26 hr/yr normal maintenance operation per engine.
c. For the TAPs analysis, CO, NO_X, and SO_2 emission rates are the worst-case emission rates for the corresponding criteria pollutants. DEP emission rates are equal to the worst-case PM_{10} emission rates. Emission factors for these pollutants are in lb/hp-hr.
d. For the CAA112 requirements, all Polyaromatic Hydrocarbons (PAH) will be considered Polycyclic Organic Matter (POM)

Diesel storage tanks are associated with both the emergency diesel generator and the firewater pump engine. The generator engine will sit atop their respective storage tanks. Storage capacities for the generator and firewater pump engines are 750 and 350 gallons, respectively. Because the tanks are smaller than 20,000 gallons, they are not subject to New Source Performance Standards (NSPS).

Cooling Towers

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

The cooling tower is configured in two parallel sets of five cells. The quantity of water released as droplets to the air (the drift rate) is based on 0.0005 percent of the water recirculation rate, and reflects the use of very high efficiency drift eliminators. The total dissolved solids (TDS) content of the drift is the maximum value estimated from local water quality measurement data water concentrated 12 times by the water recirculation cycles. PM emissions from the cooling tower displayed in Table 5.1-7 are based on the assumption that water throughput is maximized in all cooling tower cells.

TABLE 5.1-7
PARTICULATE MATTER EMISSIONS FROM THE COOLING TOWER

Water circulation rate, million lb/hr	87.6
Maximum dissolved solids, ppmw[a]	1,800
Drift, percent of circulating water	0.0005
PM_{10} emission rate, lb/hr	0.79
PM_{10} emission rate, ton/yr[b]	3.5

Short-Term Emissions Summary

Short-term maximum emission rates for operation are summarized in Table 5.1-8. This table presents emissions based on the maximum operating rate for the combustion turbines (full load with duct burners, full load, or 60 percent load, whichever is worst for the pollutant of concern), cooling tower, auxiliary boiler, emergency generator, and fire water pump. In practice, it is very unlikely that these units would all be running at their maximum capacity simultaneously.

TABLE 5.1-8
MAXIMUM SHORT-TERM NORMAL OPERATION CRITERIA POLLUTANT EMISSIONS

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 PM2.5	1-hr VOC
Combustion Turbines[a]	40.0	24.4	24.4	28.3	28.3	26.1	38.0	9.50	6.96
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

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.

5.1.2.2 Startup

Emission rates of some pollutants are higher during startup than during normal operations because combustion is not yet optimized and/or because control equipment is not functional under all operating conditions. Like automobiles, combustion turbines emit more carbon monoxide during startup because combustion is optimized for a warm engine and the typical

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 startup, primarily because the SCR system is not effective at low exhaust gas temperatures, and ammonia is generally not introduced until temperatures that promote the desired reactions are achieved.

The duration and total emissions from a combustion turbine startup depend on how long it has been shut down. Table 5.1-9 identifies startup emissions and the duration of a combustion turbine startup. 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 5.1-9
COMBUSTION TURBINE TOTAL STARTUP/SHUTDOWN EMISSIONS

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 – startup following a 72 hour or greater period of non-operation. Hot start – startup following 8 hours or less of non-operation. Warm start – startup following between 8 and 72 hours of non-operation.
b. Time for both turbines to reach 100% load for startup, and for both turbines to go from 100% load to no operation for shutdown.
c. SO2 startup/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 startups and shutdowns. Table 5.1-10 identifies short-term average emission rates for an operating scenario in which the combustion turbines are started, operated, and shut down. In cases where the averaging periods would not accommodate all three phases of operation (i.e., startup, operation, and shutdown cannot all always occur during a 1, 3, or 8-hour averaging period), time-weighted emission rates for combinations of startup and operation, operation and then shutdown, or startup were calculated. Review of the table indicates CO emissions are much higher during startups 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 startup results in lower SO_2 emissions. PM emissions are also lower during startup.

TABLE 5.1-10
SHORT-TERM COMBUSTION TURBINE EMISSION RATES INCORPORATING STARTUP AND SHUTDOWN

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 startup and a shutdown, separate average emission rates were calculated for startup and shutdown, as shown in the left-most column.

In order to account for the influence of startup and shutdown on annual average emission rates, potentially unrealistic scenarios were developed. Because the number and type (hot, warm, cold) of startups and shutdowns that will actually occur in a given year are difficult to predict, it was thought that scenarios with unrealistically frequent startup and shutdown events would, when viewed alongside the annual average emission rates developed for continuous annual operation (which are unrealistic in that they assume there are no startups or shutdowns), serve to bound the continuum of possible annual operations. Table 5.1-11 summarizes the annual emission rates calculated for various startup/operation/shutdown scenarios, and identifies the maximum emission rates for each pollutant. In all cases, the operating period between startup and shutdown was assumed to be 16 hours, and the operating scenario was assumed to be full load with duct burning. As shown in the table, almost all of the maximum emission rates result from hot starts followed by 16 hours of operation, then shutdown followed immediately by another hot startup, and a repeat of the 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 5.1-11
ANNUAL COMBUSTION TURBINE EMISSION RATES CONSIDERING STARTUP AND SHUTDOWN

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 startup per day for each day of the year.
SU = startup. SD = shutdown. Op = operation. Down = not operating

5.1.2.3 Annual Emissions

Annual emissions (typically expressed as tons per year or tpy) depend on how many hours each unit operates and the unit's operating rate during those periods. Table 5.1-12 presents annual emissions for two power generation unit operating scenarios: 1) the combustion turbines operate every hour of the year in the operating mode with the highest emissions (as noted in Table 5.1-1, this is with the CT operating at 100 percent load with duct burners for all pollutants except VOCs, which are highest at 60 percent load); and 2) the worst-case startup/shutdown scenarios from Table 5.1-11.

TABLE 5.1-12
UNITS 3 AND 4 MODIFICATION ANNUAL CRITERIA POLLUTANT EMISSIONS

	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC
Annual emissions with continuous CT operation (8,760 hours per year)						
Combustion Turbines[a] w/Duct Firing	175	107	62.8	166	41.6	30.5
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	166	41.6	51.5
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	108	63.0	170	45.1	51.7
Annual Emissions with worst case startup 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

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.

Auxiliary boiler emissions are based on full load operation for 2,500 hours in a year. Annual emissions from the firewater pump engine and generator are based on 26 hours of operation per year at maximum capacity operation. Annual PM_{10} emissions from the cooling towers are based on the assumption that the water flow rate is maximized in each cell every hour of the year. In practice, water flow may be reduced as outdoor temperatures drop or when the combustion turbine loads decrease. Consequently, this assumption provides a conservative estimate of cooling tower emissions. For the annual average startup/shutdown scenario, emissions associated with the auxiliary boiler, the cooling tower, and the emergency generator and firewater pump engines are assumed the same as the continuous operation scenario.

Table 5.1-11 indicates that frequent startups and shutdowns would decrease annual NO_x, SO_2, and PM emissions but increase annual CO and VOC emissions by 320 and 3 percent, respectively. However, as noted in Section 5.1.3, the ambient CO concentrations associated with frequent startups and shutdowns are predicted to be well below the ambient air quality standards.

5.1.2.4 Emission Standards

New Source Performance Standards

USEPA has established performance standards for a number of air pollution sources in 40 Code of Federal Regulation (CFR) Part 60. These NSPS represent a minimum level of control that is required on a new source. This section identifies those NSPS that apply to Units 3 and 4 emission units, including 40 CFR 60 Subparts A, Dc, and KKKK. In practice, the emission limits imposed by NSPS are rarely governing for new sources because the emission limits deemed BACT are virtually always lower.

Subpart A, General Provisions

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

Consistent with NSPS requirements, Grays Harbor Energy would notify EFSEC and USEPA of the anticipated initial start-up date, the actual start-up date, any changes in the facility that affect emissions, compliance sources tests, and certification tests for continuous emission monitors. Grays Harbor Energy would also maintain records of start-ups and shutdowns, malfunctions of control equipment or periods of excess emissions if they occur, and periods when continuous emission monitoring equipment is inoperative.

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

Subpart Dc applies to steam generating units that commence construction, modification, or reconstruction after June 9, 1989 and have a 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. However, Subpart Dc does not establish any emission limits for boilers fired solely with natural gas.

Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

Subpart KKKK establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that combust more than 10 million British thermal units per hour (MMBtu/hr) and commenced construction, modification, or reconstruction after February 18, 2005. The combustion turbines at Units 3 and 4 meet these criteria and will be subject (along with the associated duct burners) to the requirements of Subpart KKKK.

Subpart KKKK limits NO_x exhaust concentration to 15 ppm at 15 percent O_2 for each turbine, which is significantly higher than the proposed NO_x exhaust concentration based on BACT (2 ppmvd at 15 percent O_2). Subpart KKKK limits SO_2 emissions from each HRSG stack to 0.90 lb/MWhr, or 615 lb/hr; estimated SO_2 emissions based on the local gas supply (Williams Northwest Pipeline) are expected to be no more than 14.2 pounds per hour.

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

Subpart IIII applies to the firewater pump engine proposed for Units 3 and 4 to suppress fires when grid power is not available to operate the electric firewater pump. Engine manufacturers are required to certify engines for prescribed NO_x, PM, CO, and VOC emission standards. Engine operators are required to follow the manufacturer's operation and maintenance instructions. Subpart IIII limits emergency engines such as the firewater pump engine to 100 hours per year of non-emergency operation (e.g., maintenance and testing).

Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

Subpart Kb applies to storage vessels greater than 75 cubic meters (~20,000 gallons). The diesel storage tanks for the emergency generator and the firewater pump engine are 750 gallons and 350 gallons, respectively. Therefore, Subpart Kb does not apply.

National Emission Standards for Hazardous Air Pollutants / Maximum Achievable Control Technology Standards

Title III of the 1990 Clean Air Act Amendments requires USEPA to regulate the emissions of hazardous air pollutants (HAPs) from stationary and mobile sources.[2] USEPA does this by specific industry categories so that it can tailor the controls to the major sources of emissions and the HAPs of concern from that industry. The rules promulgated under Title III generally specify the Maximum Achievable Control Technology (MACT) that must be applied for a given industry category. Consequently, these rules are often called MACT standards.

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

Sources are subject to MACT rules only if they have a potential to emit more than 10 tpy of a single HAP or more than 25 tpy of all HAPs combined. Table 5.1-13 presents a summary of estimated potential annual HAP emissions from Units 3 and 4. HAP emissions from Units 3 and 4 are 16.1 tpy, and hexane is the HAP emitted in the greatest quantity at 8.6 tpy. The existing facility (Units 1 and 2 and associated equipment) is estimated to emit a total of 14.2 tpy, and 7.8 tpy of hexane. Following addition of Units 3 and 4, the facility-wide total HAP potential to emit would be 30 tpy, and the facility-wide hexane potential to emit would be 16.4 tpy; these emission rates exceed the MACT program applicability thresholds. Based on these emission rate calculations, the post-project facility would be subject to the MACT program. The combustion turbines would be subject to 40 CFR 63, Subpart YYYY, and the diesel engines used to power the emergency generator and fire water pump would be subject to Subpart ZZZZ.

TABLE 5.1-13
FACILITY-WIDE HAP EMISSIONS

Compound	CAS #	Emission Rate (tpy)
Acetaldehyde	75-07-0	6.64E-01
Acrolein	107-02-8	1.06E-01
Arsenic	7440-38-2	9.59E-04
Benzene	71-43-2	2.09E-01
Beryllium	7440-41-7	5.75E-05
1,3-Butadiene	106-99-0	7.14E-03
Cadmium	7440-43-9	5.27E-03
Chromium (total)	7440-47-3	6.71E-03
Cobalt	7440-48-4	4.03E-04
Dichlorobenzene	106-46-7	5.75E-03

[2] With the delisting of methyl ethyl ketone and caprolactam, the total number of HAPs is now 187.

Ethyl benzene	100-41-4	5.31E-01
Formaldehyde	50-00-0	2.13E+00
Hexane	110-54-3	8.63E+00
Manganese	7439-96-5	1.82E-03
Mercury	7439-97-6	1.25E-03
Naphthalene	91-20-3	2.45E-02
Nickel	7440-02-0	1.01E-02
Polycyclic Organic Matter	POM	3.97E-02
Propylene Oxide	75-56-9	4.81E-01
Toluene	108-88-3	2.17E+00
Xylenes	1330-20-7	1.06E+00
Maximum HAP (Hexane)	(110-54-3)	8.63E+00
Total HAPs		1.61E+01

The MACT rules for boilers (Subpart DDDDD – generally known as "the Boiler MACT") were vacated and remanded by the Court of Appeals for the District of Columbia on June 8, 2007. USEPA has stated that the Federal Clean Air Act §112(j) provisions to establish case-by-case MACT standards in the event USEPA misses a deadline for MACT promulgation may be triggered with the vacateur of the Boiler MACT, but no official guidance has been issued clarifying the path forward. USEPA is currently gathering data and is developing a new Boiler MACT proposal. In light of USEPA's effort to revise and re-issue the standard and the complexity and cost that would result if a case-by-case standard precedes issuance of the federal rule, Grays Harbor Energy asserts that the best course of action is to await issuance of the revised federal rule. This course of action would not compromise HAP emission control efforts because the proposed boiler will employ best available control technology (BACT). In the event case-by-case MACT is required for the proposed boiler, Grays Harbor Energy would propose MACT requirements reflective of the large gaseous fuel boiler source requirements specified in the vacated Boiler MACT.

Title 4 (Acid Rain) Provisions

Title 4 of the Clean Air Act (CAA) Amendments of 1990 provide a strategy for reducing national emissions of NO_x and SO_2 as part of a comprehensive plan for reducing acid deposition. 40 CFR Part 72 requires any fossil fuel-turbine larger than 25 MW to monitor flow rate, oxygen, and NO_x and SO_2. Units 3 and 4 would be subject to these regulations. Monitoring may take the form of continuous emission monitoring system (CEMS) or calculations based on fuel sulfur monitoring or similar techniques. The requirements for CEMS are similar to those required under the NSPS except that CEMs for sources subject to 40 CFR Part 72 must meet more stringent accuracy limits during annual relative accuracy test audits.

USEPA limits national SO_2 emissions attributable to power generation by capping the number of SO_2 'allowances' distributed each year. An 'allowance' corresponds to one ton of allowable SO_2 emissions. USEPA grants some older facilities a number of allowances each year; however sources built after 1996 must purchase all of their requisite allowances. Each March 1st, all

sources subject to the Acid Rain program must possess one allowance for each ton of SO_2 emitted from that facility during the previous calendar year. Each source must use its monitoring data to calculate its required number of allowances.

Title V Air Operating Permit

The Title V air operating permit program does not establish new emissions limits but may add new monitoring, record-keeping, and reporting requirements to those established during the pre-construction permitting process. Grays Harbor Energy will be required to obtain a Title V air operating permit for Units 3 and 4 as required under WAC 173-401-300, but the Title V permit is not required for the project to commence construction or operation. A Title V permit application must be filed within 12 months of the project commencing operation.

State and Local Emission Limits

Emission limits are established by the BACT review process. The BACT analysis identifies pollutant-specific alternatives for emission control and the pro's and con's of each alternative. The determination of which control scenario best protects ambient air quality is made on a case-by-case basis and considers the technical, economic, energy, and environmental costs.

Chapter 173-460 WAC requires that BACT also be employed to control emissions of TAPs (i.e., T-BACT). Generally, the same technologies or operations that reduce criteria pollutants also reduce TAPs. For example, the use of gaseous fuels instead of solid fuels reduces emissions of most criteria pollutants and TAPs. The use of combustion controls to optimize combustion also reduces both criteria pollutants and TAPs. The BACT analysis included as Appendix A-1 of the Application identifies the use of good combustion practices and gas cleaning as the BACT for TAPs.

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

ORCAA regulations mirror Ecology's emission limits for new sources. The ORCAA regulation’s opacity standard limits the plume to 20 percent opacity except for 3 minutes of any hour. Particulate matter emissions are limited to 0.1 grains per dry standard cubic foot.

The maximum PM_{10} emission rate from each combustion turbine would be (at most) about 19.0 lb/hr, including sulfates. Given flow rates of between approximately 1.0 and 0.7 million actual cubic feet per minute (acfm) from each turbine (depending upon the mode of operation), this emission rate corresponds to particulate loadings of less than 0.1 grains/actual cubic foot (gr/acf). Adjusting for standard temperature and dry exhaust, particulate matter emissions from each unit would be less than 0.0031 gr/dscf at 15 percent O_2. Thus, the anticipated grain loading is less than 4 percent of the 0.1 gr/dscf allowed by the state regulation. Plume opacity associated with grain loadings this low would be less than 5 percent, which is well below the allowed 20

percent. The anticipated SO_2 concentration would also be well below the state limit of 1,000 ppm.

Notice of Construction and Application for Approval

State law (WAC 173-400-110) requires a NOC for the construction of new or modified air contaminant sources in Washington. ORCAA maintains a similar regulation for new or modified sources in its jurisdiction. The NOC application provides a description of the facility and an inventory of pollutant emissions and controls. The reviewing agency, EFSEC, considers whether BACT has been employed and evaluates ambient concentrations resulting from these emissions to ensure compliance with ambient air quality standards. Pollutant emissions not governed by the PSD permit process would be addressed in an NOC permit.

Prevention of Significant Deterioration (PSD)

The PSD permit process was established by USEPA to ensure that new or expanded major stationary sources that emit criteria pollutants above a significance threshold do not cause air quality in areas that currently meet the standards (i.e., attainment areas) to deteriorate significantly. These regulations require the application of BACT, and set PSD increments, which limit the increases in SO_2, H_2SO_4, NO_2 and PM_{10} ambient concentrations that may be caused by a new or modified source. Increments have been established for three land classifications. The most stringent increments apply to Class I areas, which include wilderness areas and national parks. Olympic National Park is the closest Class I area to the Grays Harbor Energy Center and is about 60 km north-northwest of the proposed site. The vicinity of the site is designated Class II where less stringent PSD increments apply. There are no Class III areas in Washington so those increments are not pertinent to this analysis. Class I and Class II PSD increments are discussed further in Section 5.1.3.5.

The existing Grays Harbor Energy Center is a major stationary source because facility-wide potential emissions exceed 100 tpy. The addition of Units 3 and 4 (and the associated boiler, engines, and cooling tower) will be considered a major modification of the existing stationary source because it will increase potential emissions of NO_x, CO, SO_2, , PM_{10}, $PM_{2.5}$, VOC (surrogate for ozone), and $H_2SO_4$by more than their respective Significant Emission Rates (see Table 5.1-14). Consequently, the addition of Units 3 and 4 requires a PSD permit. With referenced appendices, Section 5.1 of the Application for Site Certification constitutes that application.

TABLE 5.1-14
PSD REVIEW APPLICABILITY ANALYSIS

Pollutant	Project Emissions[a]	SER[b]	Over SER?
NO_x	176	40	Yes
CO	451	100	Yes
SO_2	63.0	40	Yes
PM_{10}	170	15	Yes
$PM_{2.5}$ (Filterable)	45.1	10	Yes
Ozone (VOC)	53.1	40	Yes
H_2SO_4	63.3	7	Yes

a. Emission rates are in tons per year, and are the maximum emissions considering both continuous operation and worst-cast startup/shutdown scenarios.
b. SER = Significant Emission Rate (in tons per year) from 40 CFR 52.21(b)(23) except for PM2.5, which was proposed on 11/1/05 in 70 FR 65984.

5.1.2.5 Toxic and Hazardous Air Pollutants (TAPs)

WAC 173-460 governs more than 300 air pollutants it identifies as TAPs. Emissions of TAPs from industrial sources such as Units 3 and 4 that exceed prescribed Small Quantity Emission Rates (SQERs) must be evaluated with dispersion models to determine compliance with ambient air quality criteria (Acceptable Source Impact Levels, or ASILs). Table 5.1-15 compares emissions of TAPs attributable to the addition of Units 3 and 4 with the SQERs. TAPs that are emitted at rates exceeding the SQERs have been evaluated with the AERMOD dispersion model; the results of that evaluation are presented in Section 5.1.3.

TABLE 5.1-15
COMPARISON OF FACILITY-WIDE TAP EMISSION INCREASES WITH SQERS

Compound	CAS #	Emission Rate			SQER		Modeling Required?
		(lb/hr)	(lb/day)	(lb/yr)	Value	Avg Per	
Acetaldehyde	75-07-0	1.53E-01	3.68E+00	1.33E+03	71	Annual	Yes
Acrolein	107-02-8	2.45E-02	5.87E-01	2.12E+02	0.00789	24-hr	Yes
Ammonia	7664-41-7	3.70E+01	8.87E+02	3.24E+05	9.31	24-hr	Yes
Arsenic	7440-38-2	2.23E-04	5.35E-03	1.92E+00	0.0581	Annual	Yes
Benzene	71-43-2	4.99E-02	1.20E+00	4.18E+02	6.62	Annual	Yes
Benzo(a)anthracene	56-55-3	5.75E-06	1.38E-04	1.73E-02	1.74	Annual	No
Benzo(a)pyrene	50-32-8	8.34E-03	2.00E-01	7.30E+01	0.174	Annual	Yes
Benzo(b)fluoranthene	205-99-2	2.23E-06	5.34E-05	1.73E-02	1.74	Annual	No
Benzo(k)fluoranthene	207-08-9	2.35E-06	5.64E-05	1.73E-02	1.74	Annual	No
Beryllium	7440-41-7	1.34E-05	3.21E-04	1.15E-01	0.08	Annual	Yes
1,3-Butadiene	106-99-0	1.72E-03	4.12E-02	1.43E+01	1.13	Annual	Yes
Cadmium	7440-43-9	1.23E-03	2.94E-02	1.05E+01	0.0457	Annual	Yes
Carbon Monoxide	630-08-0	3.01E+01	7.22E+02	2.16E+05	50.4	1-hr	No
Chromium (hexavalent)	18540-29-9	6.24E-05	1.50E-03	5.37E-01	0.00128	Annual	Yes
Chrysene	218-01-9	2.79E-06	6.70E-05	1.73E-02	17.4	Annual	No
Cobalt	7440-48-4	9.36E-05	2.25E-03	8.05E-01	0.013	24-hr	No
Copper	7440-50-8	9.47E-04	2.27E-02	8.15E+00	0.219	1-hr	No

Compound	CAS #	Emission Rate			SQER		Modeling Required?
		(lb/hr)	(lb/day)	(lb/yr)	Value	Avg Per	
Dibenzo(a,h)anthracene	53-70-3	2.64E-06	6.32E-05	1.15E-02	0.16	Annual	No
Dichlorobenzene	106-46-7	1.34E-03	3.21E-02	1.15E+01	17.4	Annual	No
Diesel Engine Particulate	DEP	3.78E-01	9.08E+00	4.54E+00	0.639	Annual	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	1.78E-05	4.28E-04	1.53E-01	0.00271	Annual	Yes
Ethyl benzene	100-41-4	1.21E-01	2.91E+00	1.06E+03	76.8	Annual	Yes
Formaldehyde	50-00-0	4.90E-01	1.18E+01	4.25E+03	32	Annual	Yes
Hexane	110-54-3	2.01E+00	4.82E+01	1.73E+04	92	24-hr	No
Indeno(1,2,3-cd)pyrene	193-39-5	2.84E-06	6.82E-05	1.73E-02	1.74	Annual	No
Manganese	7439-96-5	4.24E-04	1.02E-02	3.64E+00	0.00526	24-hr	Yes
Mercury	7439-97-6	2.90E-04	6.96E-03	2.49E+00	0.0118	24-hr	No
3-Methylchloranthrene	56-49-5	2.01E-06	4.82E-05	1.73E-02	0.0305	Annual	No
Naphthalene	91-20-3	5.79E-03	1.39E-01	4.90E+01	5.64	Annual	Yes
Nitrogen Dioxide	10102-44-0	4.56E+01	1.10E+03	3.51E+05	1.03	1-hr	Yes
Propylene	115-07-1	5.74E-04	1.38E-02	6.89E-03	394	24-hr	No
Propylene Oxide	75-56-9	1.10E-01	2.64E+00	9.62E+02	51.8	Annual	Yes
Selenium	7784-49-2	2.68E-05	6.42E-04	2.30E-01	2.63	24-hr	No
Sulfur Dioxide	7446-09-5	2.85E+01	6.84E+02	1.26E+05	1.45	1-hr	Yes
Sulfuric acid	7664-93-9	1.44E+01	3.47E+02	1.27E+05	0.131	24-hr	Yes
Toluene	108-88-3	4.97E-01	1.19E+01	4.35E+03	657	24-hr	No
Vanadium	7440-62-2	2.56E-03	6.15E-02	2.20E+01	0.0263	24-hr	Yes
Xylenes	1330-20-7	2.43E-01	5.83E+00	2.12E+03	29	24-hr	No

5.1.3 LOCAL AIR QUALITY IMPACT ASSESSMENT

Neither an NOC nor a PSD permit may be issued unless the proposed new source or modification can demonstrate that the allowable emissions will not cause or contribute to violation of any ambient air quality standard or PSD increment. This is typically accomplished using air quality dispersion modeling to predict ambient concentrations. This section discusses the methodology used to develop near-field modeling used to predict pollutant concentrations attributable to Units 3 and 4 emissions in the Class II areas surrounding the proposed facility. Class II areas are essentially the entire country except those areas designated as Class I areas, which are National Parks, Wilderness Areas, and other areas where the smallest PSD increments have been imposed to allow the smallest degree of air quality deterioration. Class II areas have been deemed able to accommodate normal, well-managed industrial growth, and, therefore, have higher PSD increments.[3]

A modeling protocol describing proposed modeling methodologies was distributed to EFSEC, USEPA, the National Park Service, and the U.S. Forest Service on May 8, 2009. All agencies approved the protocol by July 8, 2009. The May 8 modeling protocol is provided as Appendix A-3. The only changes in the modeling that resulted from agency review of the protocol were related to the meteorological data applied to the Class I impact assessment, which is addressed in Section 5.1.4.

[3] USEPA, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting. October, 1990.

5.1.3.1 Model Selection

Regulatory modeling techniques were reviewed to select the most appropriate air quality dispersion model to simulate dispersion of air pollutants emitted by Units 3 and 4. The selection of a modeling tool is influenced by the potential for exhaust plumes from point sources to be influenced by nearby on-site structures and to impact complex terrain.

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

5.1.3.2 Modeling Procedures

AERMOD was applied to both criteria pollutant and TAP emissions using the regulatory defaults in addition to the options and data discussed in this section.

Model Setup and Application

The most recent version of AERMOD (Version 07026) 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, described in Section 5.1.3.4.

Averaging Periods

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

Chemical Transformations

The analysis conservatively assumed that 100 percent of the emitted NO_x is converted to NO_2.

5.1.3.3 Elevation Data and Receptor Network

For the preliminary air quality impact analysis, four nested grids were used to model Units 3 and 4, with the grid closest to the proposed facility having the closest spacing (50 meters or 164 feet), then a 200-meter (656-foot) grid, and, finally, an outer grid with receptors every 500 meters (1,640 feet). Also, receptors were placed every 25 meters (82 feet) along the property boundary. Following the preliminary modeling analysis, fine-grid (i.e., 25-meter spacing) receptors were added as needed to fully resolve the location and magnitude of the maximum predicted concentrations. The final receptor locations are shown in Figure 5.1-1.

Terrain elevations and hill height scale values for the receptors shown in Figure 5.1-1 were calculated using the AERMAP preprocessor (Version 09040) with 7.5-minute United States Geological Survey digital elevation model (DEM) quadrangles (Elma, Montesano, Prices Peak, and South Elma) obtained from the internet (http://www.mapmart.com). These data have a horizontal spatial resolution of about 10 m. Terrain heights surrounding the facility indicate that some receptors are likely to be located in "complex terrain" (i.e., above plume height).

5.1.3.4 Meteorological Data

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.

Surface Data

Surface meteorological data were obtained from a meteorological station located in Satsop, Washington, operated by Duke Energy North America in between April 2002 and May 2003 The 60-meter meteorological tower installed in Satsop was located approximately 0.25 miles west of the project site and used Met One instrumentation. The Satsop hourly meteorological data include the following variables at 10 meters (m), 30 m, and 60 m above ground level: wind speed, wind direction, sigma-theta, sigma-w, temperature, and relative humidity. The Satsop meteorological data also include 2 m temperature, station pressure, solar radiation, temperature difference (10 m minus 2 m), temperature difference (30 m minus 10 m), temperature difference (60 m minus 10 m), and precipitation.

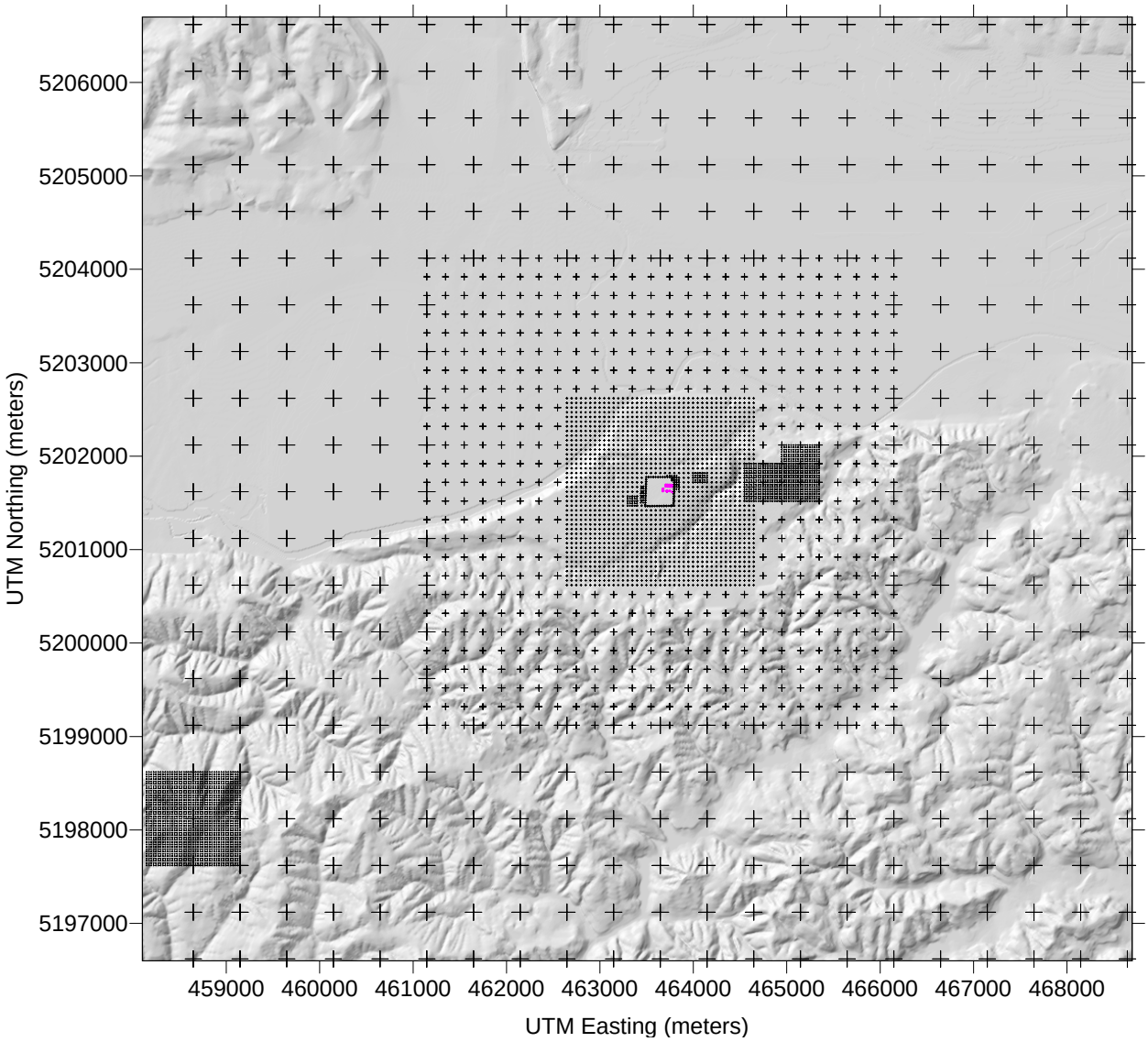

Figure 5.1-1
Receptor Locations

The Satsop meteorological data were collected specifically for prevention of significant deterioration (PSD) permit application. The sensors employed and the audit procedures used meet USEPA requirements for meteorological data to support PSD permits. The Satsop station collected the necessary data for the regulatory dispersion model AERMOD. All audits of the meteorological instruments were conducted by an employee of MFG who operated independently of the MFG employees who installed and maintained the instruments. Independent quarterly audits were conducted and the results documented in the following Grays Harbor Energy Facility Ambient Air and Meteorological Monitoring Performance Audit reports:

- Spring 2002 Quarter 1 – from an audit conducted April 30 and May 1, 2002
- Summer 2002 Quarter 2 – from an audit conducted August 20 and 21, 2002

- Fall 2002 Quarter 3 – from an audit conducted November 19, 2002
- Spring 2003 Quarter 4 – from an audit conducted May 28 and 29, 2003

Table 5.1-16 presents the Satsop data recovery for all meteorological variables. Additional information regarding the audit procedures and criteria used to invalidate data are available in the Annual Data Report for this site, which will be provided to EFSEC (MFG, Inc. 2003).

TABLE 5.1-16
SATSOP METEOROLOGICAL SITE DATA RECOVERY SUMMARY

Meteorological Parameter	Data Recovery (Percent)
	May 20, 2002 – May 19, 2003
2 m Temperature	72.03
10 m Wind Speed	99.18
10 m Wind Direction	96.87
10 m Sigma-Theta	96.11
10 m Sigma-W	78.95
10 m Temperature	90.92
30 m Wind Speed	99.37
30 m Wind Direction	99.37
30 m Sigma-Theta	99.12
30 m Sigma-W	78.98
30 m Temperature	86.32
60 m Wind Speed	99.37
60 m Wind Direction	99.37
60 m Sigma-Theta	99.37
60 m Sigma-W	79.00
60 m Temperature	99.34
60 m Relative Humidity	99.37
Delta Temperature (10 m – 2 m)	71.85
Delta Temperature (30 m – 10 m)	86.11
Delta Temperature (60 m – 10 m)	90.30
Solar Radiation	99.36
Station Pressure	99.33
Precipitation	99.37

To prevent AERMET and AERMOD from developing unrealistic vertical turbulence profiles, Sigma-w values from the Satsop meteorological site were invalidated at any vertical level with a horizontal wind speed less than one meter per second. Sigma-w values at horizontal wind speeds less than one meter per second are uncharacteristic. Vertical wind velocities are less than the

vertical anemometer threshold when horizontal wind speeds are less than approximately one meter per second.

The Satsop meteorological data were processed through AERMET as onsite data. Missing onsite meteorological data were supplemented by surface observations from the National Weather Service (NWS) station in Hoquiam, Washington (approximately 34 km west of Satsop).

Windrose plots presenting wind speed and wind direction data for the one year period at all three vertical observation levels were developed and are presented in the modeling protocol attached as Appendix A-3. The windroses show that the winds are predominantly from the west to south-southwest directions at all three vertical levels and from the east-northeast direction with increasing frequency at the 30 m and the 60 m heights. The wind flow patterns generally follow the Chehalis River valley. The average 10 m wind speed is 2.1 meters per second (m/s) and calm conditions occur less than three percent of the time. Overall, the average wind speed increases and the calm conditions decrease from 10 m to 60 m.

Upper Air

Upper air data from the NWS site in Quillayute, Washington were used for the one-year meteorological dataset. The Quillayute upper air data were collected from the National Oceanic and Atmospheric Administration (NOAA) Forecast Systems Laboratory Radiosonde Database (http://raob.fsl.noaa.gov).

Land Use Processing

Surface parameters including the surface roughness length, albedo, and Bowen ratio were determined for the area surrounding the Satsop meteorological tower using the AERMET preprocessor, AERSURFACE (Version 08009), and the USGS 1992 National Land Cover (NLCD92) land-use data set.[4] The NLCD92 data set used in the analysis has a 30 m mesh size and 21 land-use categories. Seasonal surface parameters were determined using AERSURFACE according to the USEPA guidance.[5]

AERMET Processing

The USEPA meteorological program AERMET was used to combine the Satsop data (missing data substituted with Hoquiam NWS data) with Quillayute NWS upper air soundings to derive the necessary meteorological variables for AERMOD. When surface temperature difference data was available, the Bulk-Richardson option was used to estimate dispersion variables and surface energy fluxes during nocturnal periods.

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[4] The USGS NLCD92 data set is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.
[5] The AERMOD Implementation Guide (USEPA 2008) and the AERSURFACE User's Guide (EPA-454/B-08-001, January 2008).

5.1.3.5 Existing Air Quality

The USEPA's AirData website (http://www.epa.gov/air/data/info.html) is a database that contains air quality data from monitoring sites across the United States and allows users to access air quality data for specific monitoring sites. Air quality measurement data for the period 2005 through 2008 were examined for monitoring sites in Seattle, Yelm, and Anacortes, for CO, NO_2, SO_2, and ozone and sites in Aberdeen and Oakville for $PM_{2.5}$. Data collected at Aberdeen and Oakville for $PM_{2.5}$ was obtained from Ecology's website. In general, these stations are located where there may be air quality problems, and so are usually in or near urban areas or close to specific large air pollution sources. On-site monitoring are available for PM_{10} and SO_2.

Ecology and USEPA designate regions as being "attainment" or "nonattainment" areas for particular air pollutants based on monitoring information collected over a period of years. Attainment status is therefore a measure of whether air quality in an area complies with the health-based ambient air quality standards displayed in Table 3.2-1. Grays Harbor County, where the Grays Harbor Energy facility is located, is in attainment for all air pollutants.

The monitoring data from the various sites can be used to characterize existing air quality at the site. Note that many of the referenced sites are located in more urban areas, and referencing those concentrations overstates the concentrations that would be expected at the rural Grays Harbor Energy Center site. A summary of these data is presented in Table 5.1-17. All observed pollutant concentrations at these monitoring sites are lower than the NAAQS and WAAQS.

- NO_2 was monitored in Seattle and Anacortes, where the maximum annual concentrations were less than 36 and 22 percent of the NAAQS, respectively.

- CO was monitored in Seattle, where the maximum concentrations were less than 8 percent of the 1-hour average NAAQS and less than 22 percent of the 8-hour average NAAQS.

- SO_2 was monitored in Seattle for the years 2005, 2007, and 2008 and on the Grays Harbor Energy Center site for a one-year period between May of 2002 and 2003. The maximum concentrations in Seattle and at the project site were less than 20 and 6 percent of the NAAQS, respectively.

- The 4th highest maximum 8-hour ozone concentration monitored in Yelm, WA was about 91 percent of the 8-hour NAAQS.

- PM_{10} concentrations were monitored at two locations on the project site for a one-year period between May of 2002 and 2003. Average 24-hour concentrations were less than 15 percent of the NAAQS at both locations. Annual average concentrations were 18 to 20 percent of the NAAQS.

- $PM_{2.5}$ was monitored in Aberdeen and Oakville, both approximately 16 miles from the project site, where the average of the 98th percentile 24-hour concentration over 2007 and 2008 was 49 percent of the 24-hour NAAQS at both locations. The annual

averages at Aberdeen and Oakville were 45 and 41 percent of the NAAQS, respectively.[6]

TABLE 5.1-17
AMBIENT AIR QUALITY MONITORING DATA

Pollutant	Averaging Period	Data Source[b]	Maximum Concentration[a]					Ambient Standard[d]
			2005[c]	2006	2007	2008	Average	
NO_2 (ppm)	Annual	a	0.018	0.018	--	--	0.018	0.053
	Annual	b	0.008	0.006	0.008	0.011	0.008	0.053
CO (ppm)	1 Hour	a	2.7	2.0	1.4	1.2	1.8	35
	8 Hours	a	1.9	1.2	1.0	0.9	1.3	9
SO_2 (ppm)	1 Hour	c1	0.006	--	--	--	0.006	0.4
	3 Hours	c1	0.004	--	--	--	0.004	0.5
	24 Hours	c1	0.004	--	--	--	0.004	0.1
	Annual	c1	0.001	--	--	--	0.001	0.02
	1 Hour	c2	0.007	--	--	--	0.007	0.4
	3 Hours	c2	0.006	--	--	--	0.006	0.5
	24 Hours	c2	0.006	--	--	--	0.006	0.1
	Annual	c2	0.001	--	--	--	0.001	0.02
Ozone (ppm)	8 Hours	d	0.059	0.068	0.054	0.060	0.060	0.075[e]
PM_{10} ($\mu g/m^3$)	24 Hours	c1	22.1	--	--	--	22.1	150
	Annual	c1	9.8	--	--	--	9.8	50
	24 Hours	c2	21.6	--	--	--	21.6	150
	Annual	c2	9.0	--	--	--	9.0	50
$PM_{2.5}$[f] ($\mu g/m^3$)	24 Hours	e	--	--	18.3	15.6	17.0	35
	Annual	e	--	--	6.7	6.9	6.8	15
	24 Hours	f	--	--	19.7	14.5	17.1	35
	Annual	f	--	--	6.2	6.2	6.2	15

a. From USEPA AIRS database (http://www.epa.gov/air/data/info.html) and Washington Dept. of Ecology website (https://fortress.wa.gov/ecy/enviwa/), both accessed February 2009. PM_{10} and some SO_2 data from monitoring conducted at the Grays Harbor Energy Center site between May 2002 and May 2003.
b. Data sources are as follows:
a – Seattle, WA (4103 Beacon Hill S)
b – Anacortes, WA (Casino Drive/North End Site)
c1 – Grays Harbor Energy Site, Station 1, May 2002 – May 2003
c2 – Grays Harbor Energy Site, Station 2, May 2002 – May 2003
d – Yelm, WA (709 Mill Rd Se for 2005 data, 931 Northern Pacific Road for 2006-2008 data)
e – Aberdeen, WA (359 N Division St)
f – Oakville, WA (252 Howanut Dr)
c. The data for PM10 and some SO2 from monitoring locations c1 and c2 on the Gray Harbor Energy Center site are from the monitoring period between May 2002 and May 2003.
d. The most stringent standard from NAAQS and WAAQS.
e. Attainment based on 3-year average of the 4th highest daily maximum 8-hour ozone concentration at each monitoring location
f. $PM_{2.5}$ 24-hour average is based on the 98th percentile; the annual standard is based on a three year average.

[6] These comparisons ignore temporal and annual averaging that is a consideration with the $PM_{2.5}$ standards. Consequently, existing concentrations are probably a lower percentage of the ambient standards.

5.1.3.6 Emission Source Release Parameters

Figure 5.1-2 shows the locations of emission sources included in the modeling analysis, as well as significant structures that could potentially influence emissions from the point sources. A summary of the release parameters used to represent the point sources in the simulations is presented in Table 5.1-18. The release parameters are based on information provided by the CT manufacturer (GE Energy) for a range of operating scenarios and ambient conditions.

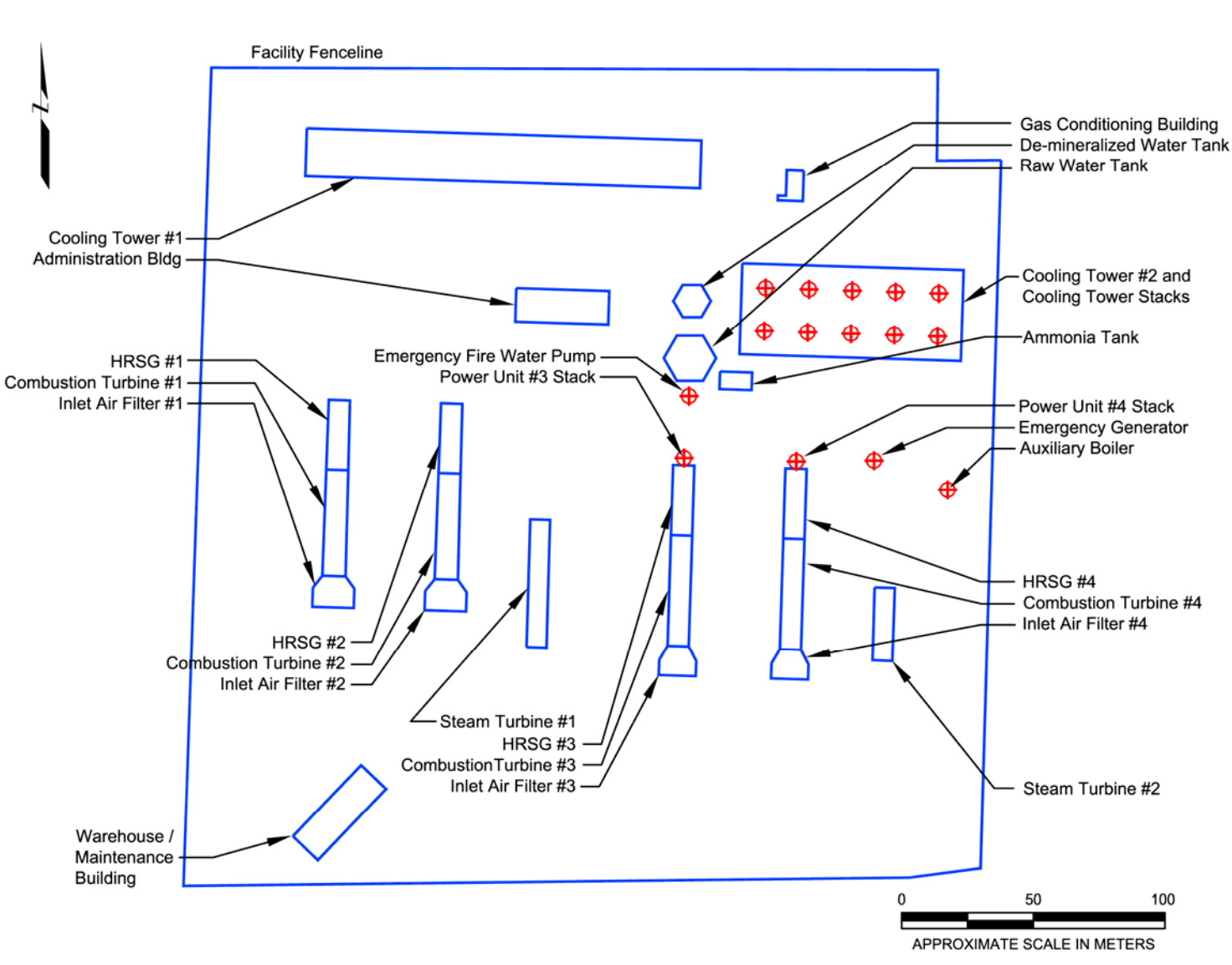

Figure 5.1-2
Emission Sources and Significant Structures Included in the Modeling Simulations

TABLE 5.1-18
POINT SOURCE RELEASE PARAMETERS

Source[a]		Coordinates			Stack Height (m)	Exhaust Temp.[a] (K)	Exit Vel.[a] (m/s)	Stack Diam. (m)
		UTM(X)	UTM(Y)	Z				
CT3	100% Load	463675.4	5201628.6	93	54.9	348 - 345	20.5 - 17.7	5.49
	100% Load w/ DB					356 – 353	20.8 – 18.0	
	60% Load/Startup[b]					349 - 344	14.1 – 13.2	
CT4	100% Load	463718	5201627.3	93	54.9	348 - 345	20.5 - 17.7	5.49
	100% Load w/ DB					356 – 353	20.8 – 18.0	
	60% Load/Startup[b]					349 - 344	14.1 – 13.2	
Auxiliary Boiler		463775.5	5201616.4	94	14.9	477	20.8	0.54
Firewater Pump		463747.6	5201627.6	93	10.7	829	72.7	0.13
Emergency Diesel Generator		463677.3	5201652.2	94	12.2	761	94.6	0.15
Cooling Tower Stack 1		463706.4	5201693.5	92	15.8	312	5.4	12.98
Cooling Tower Stack 2		463722.9	5201693	92	15.8	312	5.4	12.98
Cooling Tower Stack 3		463739.3	5201692.5	92	15.8	312	5.4	12.98
Cooling Tower Stack 4		463755.8	5201691.9	92	15.8	312	5.4	12.98
Cooling Tower Stack 5		463772.2	5201691.4	92	15.8	312	5.4	12.98
Cooling Tower Stack 6		463705.9	5201677	92	15.8	312	5.4	12.98
Cooling Tower Stack 7		463722.3	5201676.5	92	15.8	312	5.4	12.98
Cooling Tower Stack 8		463738.8	5201676	92	15.8	312	5.4	12.98
Cooling Tower Stack 9		463755.3	5201675.5	92	15.8	312	5.4	12.98
Cooling Tower Stack 10		463771.7	5201675	92	15.8	312	5.4	12.98

UTMX, UTMY based on UTM zone 10.
All coordinates, heights, and elevations in meters (m)
a. Exhaust temperatures and exit velocities for two CTs (a "stored" unit, and an "uprated" unit) and three ambient conditions (20 °F/30 %RH, 59 °F/60 %RH, and 90 °F/60 %RH) were provided by the CT manufacturer. The values shown are the maximum and minimum considered in the modeling for each operating scenario.
b. Because the exhaust temperature and exit velocity vary throughout the startup/shutdown process, the temperature and velocity for the 60% load scenario were used to represent the startup/shutdown scenario.

In addition to release parameters, the building dimensions and facility configuration were provided to AERMOD to assess potential downwash effects. Wind-direction-specific building profiles were prepared for the model using USEPA's Building Profile Input Program for the PRIME algorithm (BPIP-PRIME). The facility layout and building elevations provided by Grays Harbor Energy were used to prepare data for BPIP-PRIME, which provides the necessary input data for AERMOD. Figure 5.1-2 shows the configuration of significant structures that were used to develop the BPIP-PRIME input files, and Table 5.1-19 presents the heights of the significant structures included in the simulations.

TABLE 5.1-19
HEIGHTS AND ELEVATIONS OF SIGNIFICANT ON-SITE STRUCTURES

Structure	Coordinates					Height
	UTM(X)	UTM(Y)	X len	Y len	Z	
HRSG #1	463539.5	5201624.3	10.92	36.04	93	24.4
Combustion Turbine #1	463538.0	5201583.7	8.8	40.3	93	7.9
Inlet Air Filter #1	463534.2	5201571.9	28.99	11.93	93	22.3
HRSG #2	463582.2	5201622.9	10.92	36.04	93	24.4
Combustion Turbine #2	463580.7	5201582.4	8.8	40.3	93	7.9
Inlet Air Filter #2	463576.9	5201570.6	28.99	11.93	93	22.3
Steam Turbine #1	463747.0	5201551.4	7.48	27.8	93	14.0
Cooling Tower #1	463531.6	5201736.1	18.3	149.9	93	15.85
HRSG #3	463670.4	5201599.1	8.06	26.87	93	24.4
Combustion Turbine #3	463669.2	5201557.0	19.1	45.65	93	7.9
Inlet Air Filter #3	463665.8	5201545.8	14.06	20.7	93	22.3
HRSG #4	463713.1	5201597.8	8.06	26.87	93	24.4
Combustion Turbine #4	463711.8	5201555.6	19.14	45.65	93	7.9
Inlet Air Filter #4	463708.5	5201544.5	14.06	20.7	93	22.3
Steam Turbine #2	463747.0	5201551.4	7.48	27.8	93	14.0
Cooling Tower #2	463696.5	5201668.2	84.12	34.75	93	15.85
Raw water tank	463672.7	5201658.0	25.9	13.1	93	15.2
Demineralized Water Tank	463674.9	5201682.4	12.48	12.48	93	11.9
Ammonia Tank	463688.9	5201654.9	12.2	6.71	93	7.9
Warehouse/Maintenance Bldg	463526.9	5201484.3	18.29	18.29	93	7.6
Gas Conditioning Bldg	463711.0	5201726.8	9.5	11.6	93	5.5

UTMX, UTMY describe the southwest point of the building in UTM zone 10. The other building coordinates can be calculated from the X len and Y len data.
All coordinates, lengths, heights, and elevations in meters (m)

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

5.1.3.7 Project Air Quality Impact Analysis Results

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.[7] Note that this subsection

[7] Two $PM_{2.5}$ modeling analyses were conducted, one with filterable $PM_{2.5}$ per USEPA 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; startup and shutdown emissions are evaluated in the next subsection.

Because the initial receptor grids had receptors spaced more than 25-meters apart, additional modeling was conducted with fine-grid receptors spaced at 25 meters. The fine-grid receptors were placed in the areas between the predicted maximum and highest second high concentration initial receptors and the next nearest initial receptors. These fine-mesh receptors more fully resolve the maximum predicted concentrations. The final receptors (initial plus the added fine-mesh receptors grids) are shown in Figure 5.1-1.

Table 5.1-20 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 the State of Washington accepts as insignificant with respect to maintaining compliance with the NAAQS, WAAQS, and PSD increments.

TABLE 5.1-20
MAXIMUM PREDICTED CRITERIA POLLUTANT CONCENTRATIONS ATTRIBUTABLE TO UNITS 3 AND 4
(µg/m^3)

Pollutant	Averaging Period	Maximum Concentration[a]	SMC	SIL[b]	Over the SIL?
NO_2	Annual	0.0889	14	1	No
CO	1-Hour	365	NA	2,000	No
	8-Hour	18.1	575	500	No
SO_2	1-Hour	29.9	NA	30	No
	3-Hour	9.99	NA	25	No
	24-Hour	1.38	13	5	No
	Annual	0.0311	NA	1	No
PM_{10}	24-Hour	2.71	10	5	No
	Annual	0.127	NA	1	No
$PM_{2.5}$ (Filterable)	24-Hour	0.836	NA	NA[c]	NA
	Annual	0.0485	NA	NA[c]	NA
$PM_{2.5}$ (Total)	24-Hour	2.71	NA	NA[c]	NA
	Annual	0.127	NA	NA[c]	NA

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 PM2.5 have been proposed but have not been promulgated

As shown in Table 5.1-20, all predicted concentrations are less than the monitoring thresholds and established PSD SILs.

Table 5.1-21 presents the results of the TAP modeling analysis. As shown in this table, the simulations demonstrated that emissions attributable to Units 3 and 4 (and associated support units) comply with applicable ASILs.

TABLE 5.1-21
MAXIMUM PREDICTED TOXIC AIR POLLUTANT CONCENTRATIONS ATTRIBUTABLE TO UNITS 3 AND 4
(µg/m^3)

Compound	CAS #	Averaging Period	ASIL[a]	Maximum Predicted[b]	Over ASIL?
Acetaldehyde	75-07-0	Annual	0.37	0.000349	No
Acrolein	107-02-8	24-hr	0.06	0.00138	No
Ammonia	7664-41-7	24-hr	70.8	2.11	No
Arsenic	7440-38-2	Annual	0.000303	0.00000074	No
Benzene	71-43-2	Annual	0.0345	0.000111	No
Benzo(a)pyrene	50-32-8	Annual	0.000909	0.0000192	No
Beryllium	7440-41-7	Annual	0.000417	0.00000004	No
1,3-Butadiene	106-99-0	Annual	0.00588	0.00000377	No
Cadmium	7440-43-9	Annual	0.000238	0.00000408	No
Chromium (hexavalent)	18540-29-9	Annual	0.00000667	0.00000021	No
Diesel Engine Particulate	DEP	Annual	0.00333	0.00325	No
7,12-Dimethylbenz(a)anthracene	57-97-6	Annual	0.0000141	0.00000006	No
Ethyl benzene	100-41-4	Annual	0.4	0.000279	No
Formaldehyde	50-00-0	Annual	0.167	0.00114	No
Manganese	7439-96-5	24-hr	0.04	0.00002	No
Naphthalene	91-20-3	Annual	0.0294	0.0000131	No
Nitrogen Dioxide	10102-44-0	1-hr	470	402	No
Propylene Oxide	75-56-9	Annual	0.27	0.000253	No
Sulfur Dioxide	7446-09-5	1-hr	660	29.9	No
Sulfuric acid	7664-93-9	24-hr	1	0.823	No
Vanadium	7440-62-2	24-hr	0.2	0.00015	No

a. ASIL = Acceptable Source Impact Level, from WAC 173-460-150.
b. Maximum from all operating scenarios.

5.1.3.8 Ambient Standard Analysis

Although SILs have not been promulgated for $PM_{2.5}$, it may be appropriate to evaluate total $PM_{2.5}$ concntrations. If the maximum average background concentration (17.1 µg/m^3, see Table 5.1-17) is added to the maximum predicted concentration (2.71 µg/m^3), the total concentration of 19.8 µg/m^3 compares favorably with 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.

5.1.3.9 Startup Analysis

To demonstrate that ambient air quality standards will not be exceeded during startup, model simulations were developed for the short-term startup scenario emission rates described in Section 5.1.2.2. AERMOD was applied using the methodology developed for the normal operating scenario simulations and all stack parameters for the combustion turbines. CO is the only criteria pollutant with a short-term standard expected to increase during startup. As shown in Table 5.1-12, NO_x is the only criteria pollutant with an annual standard for which emissions associated with a worst-case annual startup and shutdown scenario would exceed those of worst-

case continuous operation. Table 5.1-22 presents a summary of the results of the startup simulations, and indicates that none of the applicable ambient standards would be exceeded as a result of startup or shutdown.

TABLE 5.1-22
MAXIMUM PREDICTED STARTUP ANALYSIS CRITERIA POLLUTANT CONCENTRATIONS
(µg/m^3)

Pollutant	Averaging Period	Worst-Case Startup[a]	Background	Total[b]	NAAQS[c]	Over AAQS?
NO_2[d]	Annual	0.125	34.0	34.1	100	No
CO	1-Hour	1,268	7,021	8,290	40,000	No
	8-Hour	44.1	5,266	5,310	10,000	No

a. Maximum from all startup scenarios.
b. Sum of the maximum predicted concentration attributable to Kalama Energy during startup and the background concentration.
c. NAAQS = Ambient Air Quality Standard.
d. NO2 was assumed to be 75 percent of emitted NOX.

5.1.3.10 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. Table 5.1-13 indicates potential annual emissions of NO_x and VOCs exceed 100 tpy. An ozone impact analysis that includes all post-project emissions is presented in Appendix A-4.

ENVIRON acquired the relevant input data and control files and replicated the MM5/SMOKE/CMAQ runs performed by Washington State University for the Puget Sound Clean Air Agency 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. We 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 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 1 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) observation site is less than 0.0004 ppb.

5.1.4 REGIONAL AIR QUALITY IMPACT ASSESSMENT

PSD regulations require 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. Through the PSD program, the Clean Air Act provides special protection for Class I areas. The FLMs for the Class I areas, 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.

Both long-term and short-term AQRV criteria and PSD increments were assessed in the Class I modeling analysis. Several simulations were performed using different sets of emission and source combinations for Unit 3 and 4 sources. At the request of USEPA, the FLMs, and EFSEC, cumulative simulations were also performed using permitted emissions from existing Unit 1, Unit 2, and related sources. The proposed emission cases are as follows:

1. Maximum 24-hour emissions from proposed Unit 3 and 4 sources: Unit 3, Unit 4, Auxiliary Boiler 2, Diesel Generator 2, Fire Pump 2, and Cooling Tower 2. For each source and pollutant (SO_2, NOx, and PM_{10}) the maximum short-term emissions address multiple load and start-up conditions as discussed in Section 5.1.2.

2. Maximum annual emissions from proposed Unit 3 and 4 sources: Unit 3, Unit 4, Auxiliary Boiler 2, Diesel Generator 2, Fire Pump 2, and Cooling Tower 2. For each source and pollutant the maximum annual emissions address multiple load and start-up conditions as discussed in Section 5.1.2.

3. Case 1 above plus maximum permitted 24-hour emissions from existing Unit 1 and 2 sources: Unit 1, Unit 2, Auxiliary Boiler 1, Diesel Generator 1, Fire Pump 1, and Cooling Tower 1.

4. Case 2 above plus maximum permitted annual emissions from existing Unit 1 and 2 sources: Unit1, Unit 2, Auxiliary Boiler 1, Diesel Generator 1, Fire Pump 1, and Cooling Tower 1.

Case 1 and Case 2 will be used for comparisons against screening level criteria. AQRV results for Case 3 and Case 4 will provided for information purposes only at the request of the FLMs.

The modeling procedures used in the AQRV analysis were described in a protocol that was reviewed by EFSEC, USEPA, and the FLMs (ENVIRON 2009). Following the submittal of the protocol, USEPA issued revised draft guidance for Class I AQRV analyses (USEPA et al. 2009). The methods used in the current analysis incorporate the FLM comments on the protocol and include FLM recommended modifications to the protocol to conform to the USEPA revised draft guidance (D. Morse and J. Notar, personal communications; R. Graw, personal communication 2009).

5.1.4.1 Assessment of Air Quality Related Values for Class I Areas

The locations of the Class I areas and modeling domain in relation to the Grays Harbor Energy Center site are shown in Figures 5.1-3 and 5.1-4. For projects subject to PSD review, an AQRV analysis is required for Federal Class I areas within 100 km of the site. The AQRVs of concern include visibility, soil, flora, fauna, and aquatic resources. Potential impacts to these AQRVs are characterized based on predictions of total nitrogen and/or sulfur deposition flux, change in light extinction, and pollutant concentrations. Pollutant concentration predictions are also used to assess Class I area increment consumption for pollutants subject to PSD review. In the Pacific Northwest, the FLMs and state agencies typically request the model domain be extended to include additional Class I areas within 200 km.

As shown in Table 5.1-23, the Olympic National Park is located 58 km north of the Grays Harbor Energy Center site and is the closest Class I area. An AQRV analysis is required for Olympic National Park, and five other Class I areas are within the 200 km expanded range recommended by the FLMs. The current analysis also includes the Mt. Hood Wilderness Area that is just outside 200 km from the site. Although it is not a Class I area, Washington State Department of Ecology (Ecology) and the FLMs requested that the Columbia River Gorge National Scenic Area (CRGNSA) be included in AQRV analyses for informational purposes.

The USFS in their review of the modeling protocol applied a screening procedure based on the distances in Table 5.1-23 and project emissions. Based on the results of their analysis, the USFS did not request an AQRV analysis for Class I areas under their administration (R. Graw, personal communication 2009). However a PSD increment analysis is still required for all Class I areas and in anticipation of requests from other interested parties, predicted AQRV impacts in the USFS Class I areas were assessed in the Class I modeling analysis.

Model Selection

The USEPA's *Guideline on Air Quality Models* (codified as Appendix W to 40 CFR Part 51, hereafter referred to as the *Guideline*) identifies the CALPUFF modeling system as the USEPA's preferred model for long-range transport assessments and for evaluating potential impacts on Class I areas. Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; complex three-dimensional wind regimes; and the effects of humidity on regional visibility.

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 system is comprised of three main components: the CALPUFF dispersion model, the CALMET meteorological pre-processor, and the CALPOST post-processor. A number of other utilities provided with the system were also applied to aid in the preparation of the meteorological/geophysical data and to manipulate the large CALPUFF output files.

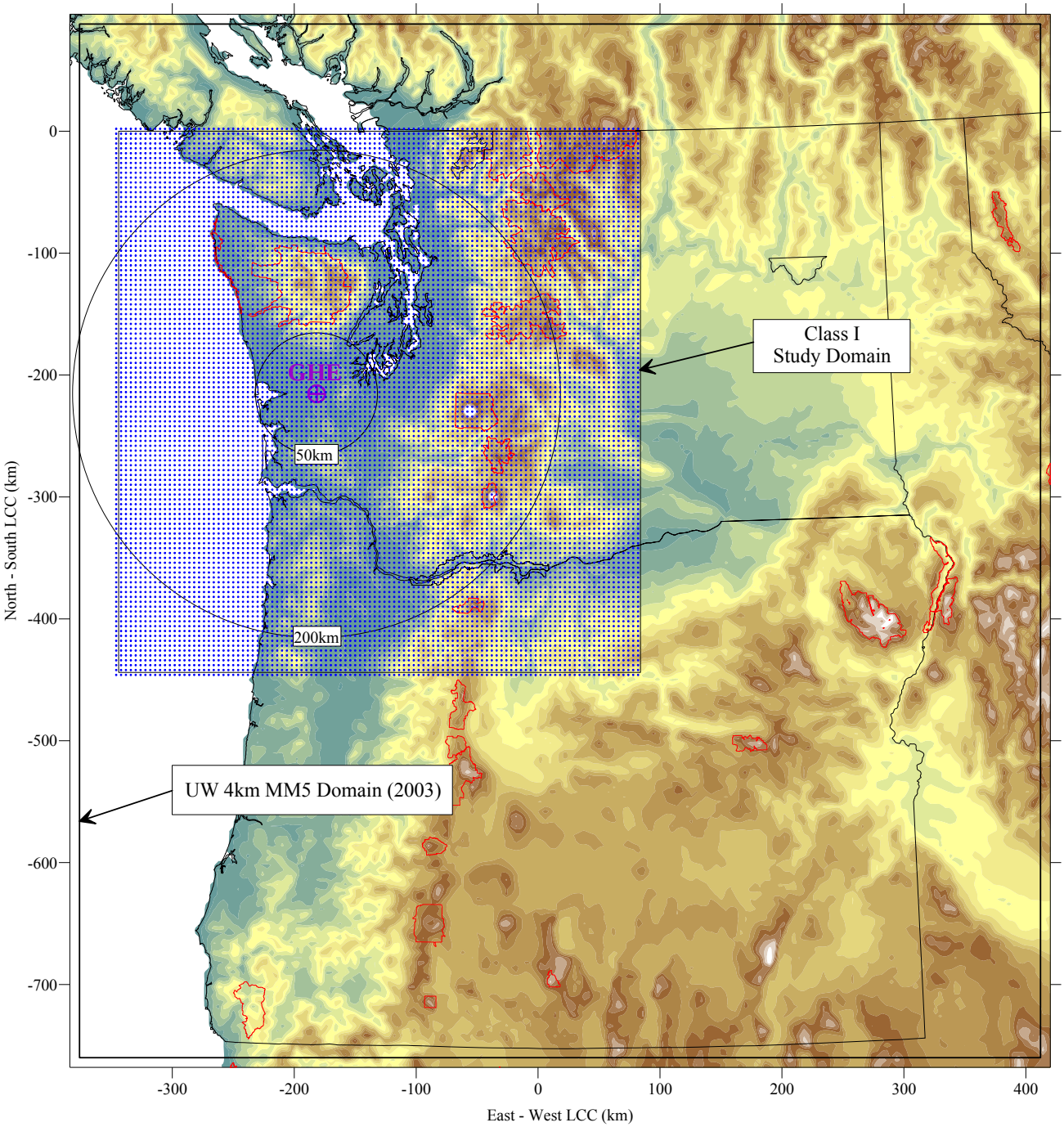

Figure 5.1-3
Modeling Domain for AQRV Analysis

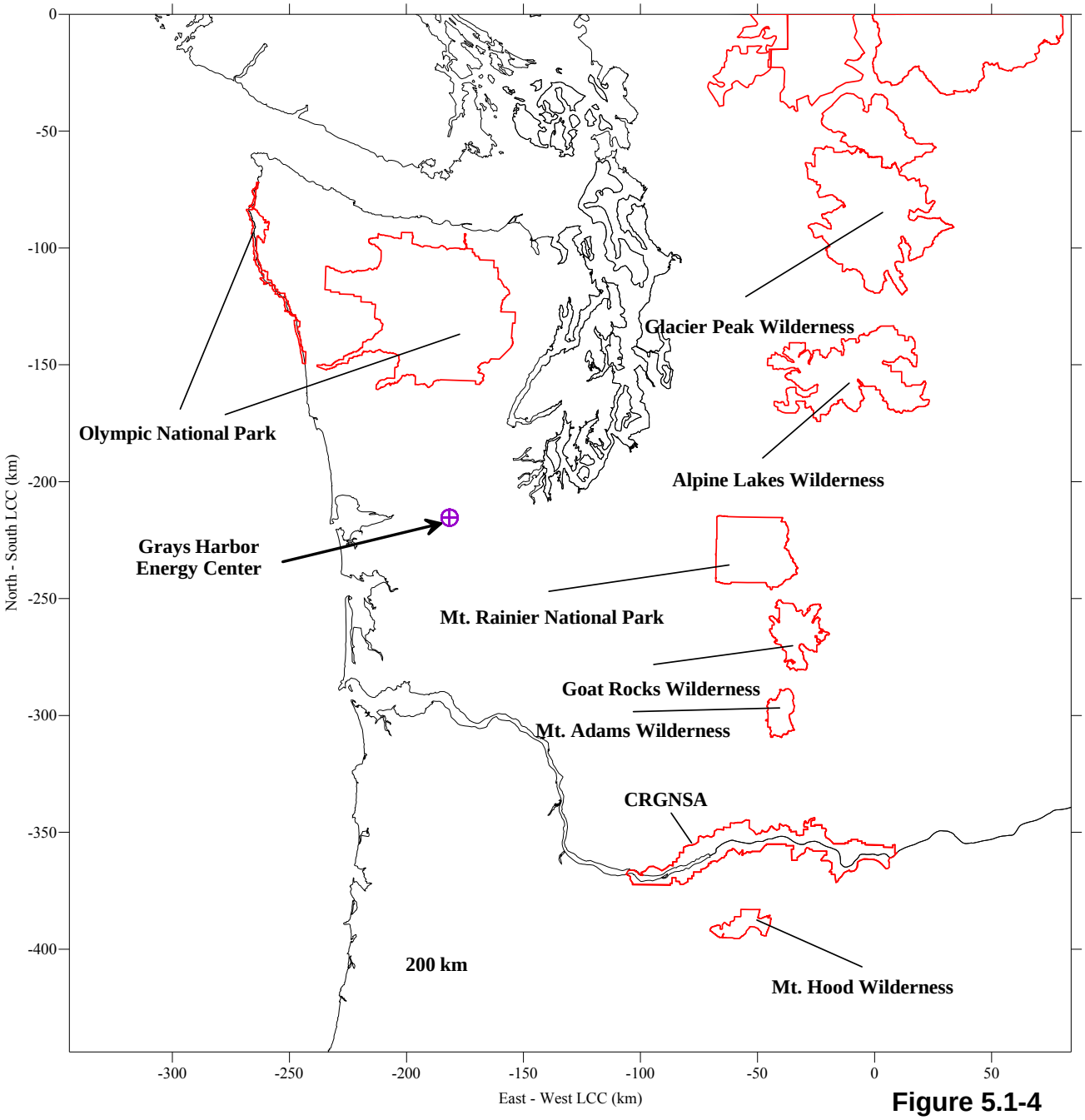

Figure 5.1-4

Locations of Class I Areas and the CRGNSA within the AQRV Modeling Domain

TABLE 5.1-23
CLASS I AREA DISTANCES 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.

CALPUFF Modeling Domain

The modeling domain for the CALPUFF simulations is shown in Figure 5.1-3 and Figure 5.1-4 The 428 km-by-444 km domain is large enough to include the Class I areas of interest with at least a 50 km allowance for complex flows that might cause recirculation of plumes originating at Grays Harbor Energy. A Lambert conformal coordinate system was used and selected to be a sub-domain of the coordinate system used by the University of Washington (UW) for their MM5 simulations of Pacific Northwest Weather. The UW MM5 simulations were used to construct the three dimensional meteorological data used in the CALPUFF analysis.

CALPUFF Modeling Procedures

The CALPUFF modeling procedures follow the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM) and the FLMs Air Quality Related Values Workgroup (FLAG), 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 (USEPA et al. 2009, USFS et al. 2008).

Emission Rates and PM_{10} Speciation

CALPUFF simulations were performed using both annual and 24-hour emission rates. The emission rates used in the simulations for Units 3 and 4 sources are summarized in Table 5.1-24 and Table 5.1-25 for the 24-hour and annual averaging periods, respectively. The derivation and assumptions for the criteria pollutant emission rates are provided in Section 5.1.2. For the short-term simulations, the maximum emission rate for each pollutant was used, and in some instances, the emission rates occur under different operating scenarios; this is a conservative assumption because it overstates actual operating conditions. Both continuous operation emissions and start-up emission cases were considered in the development of the maximum emissions used for the Class I assessment.

TABLE 5.1-24
SPECIATED 24-HOUR EMISSION RATES FOR AQRV ANALYSIS
(lbs/hr)

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2$ -SO_4	SO_4	NO_3	EC	OC	PMF	PMC
HRSG Unit 3[a,b]	8.700	28.947	19.000	8.972	6.525	0.000	4.750	5.278	0.000	0.000
HRSG Unit 4[a,b]	8.700	28.947	19.000	8.972	6.525	0.000	4.750	5.278	0.000	0.000
Aux Boiler 2 [c]	0.156	0.322	0.147	0.029	0.021	0.001	0.000	0.088	0.028	0.000
Diesel Generator 2[d]	0.000	0.164	0.008	0.000	0.000	0.000	0.006	0.002	0.000	0.000
Fire Pump 2[d]	0.000	0.057	0.008	0.000	0.000	0.000	0.006	0.002	0.000	0.000
Cooling Towers[e]	0.000	0.000	0.788	0.000	0.000	0.000	0.000	0.000	0.788	0.000

a. Speciation based on NPS recommendations for gas-fired turbines where 25% of the PM_{10} is assumed to be filterable and consist of elemental carbon (EC) or soot. The condensable fraction is assumed to consist of ammonium sulfate ($(NH_4)_2SO_4$) from one third conversion of SO_2 and the remainder is organic carbon (OC).
b. SO2 emissions were reduced to account for the amount of sulfur converted (one third) to ammonium sulfate.
c. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 10600602.
d. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 20100102.
e. All PM10 was assumed to consist of fine crustal mass (PMF).

TABLE 5.1-25
SPECIATED ANNUAL EMISSION RATES FOR AQRV ANALYSIS
(lbs/hr)

Source	SO_2	NO_X	PM_{10}	$(NH_4)_2$ $-SO_4$	SO_4	NO_3	EC	OC	PMF	PMC
HRSG Unit 3[a,b]	4.781	20.008	19.000	4.930	3.586	0.000	4.750	9.320	0.000	0.000
HRSG Unit 4[a,b]	4.781	20.008	19.000	4.930	3.586	0.000	4.750	9.320	0.000	0.000
Aux Boiler 2[c]	0.024	0.092	0.042	0.008	0.006	0.001	0.000	0.025	0.008	0.000
Diesel Generator 2[d]	0.000	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Fire Pump 2[d]	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Cooling Towers[e]	0.000	0.000	0.788	0.000	0.000	0.000	0.000	0.000	0.788	0.000

a. Speciation based on NPS recommendations for gas-fired turbines where 25% of the PM10 is assumed to be filterable and consist of elemental carbon (EC) or soot. The condensable fraction is assumed to consist of ammonium sulfate ((NH4)2SO4) from one third conversion of SO2 and the remainder is organic carbon (OC).
b. SO2 emissions were reduced to account for the amount of sulfur converted (one third) to ammonium sulfate.
c. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 10600602.
d. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 20100102.
e. All PM10 was assumed to consist of fine crustal mass (PMF).

Data characterizing the chemical composition and size distribution of the PM_{10} emitted are needed for the regional haze assessment using the CALPUFF modeling system. PM_{10} was divided or "speciated" into components as shown in Table 5.1-24 and Table 5.1-25. The six species are sulfate (SO_4), nitrate (NO_3), elemental carbon (EC), organic carbon (OC), fine crustal mass (PMF) and coarse crustal mass (PMC). Cooling tower emissions are assumed to be entirely PMF. Following NPS guidance for gas-fired turbines,[8] all of the PM_{10} emissions are assumed to be $PM_{2.5}$ (no PMC emissions). The filterable fraction is assumed to be 25 percent of the PM_{10} emissions and to consist of EC. The remaining condensable fraction is assumed to be OC and ammonium sulfate, where the amount of ammonium sulfate is based on a 33 percent conversion of the SO_2. To avoid double counting the sulfur emissions from the gas-turbines, SO_2 emissions in the simulations were reduced by the amount assumed to be emitted as ammonium sulfate. Ammonium nitrate and PMF emissions are assumed to be negligible.

For the diesel-fired generator, fire pump, and auxiliary boiler, $PM_{2.5}$ fractions were extracted from a database provided by Ecology for use in Best Available Retrofit Technology (BART) modeling analyses. The $PM_{2.5}$ fractions in the database are based on profiles recommended by the USEPA for the Community Multi-Scale Air Quality (CMAQ) model.[9] CMAQ is the preferred regulatory model for $PM_{2.5}$ and regional haze simulations. The CMAQ profile database is indexed by Source Classification Code (SCC). The analysis assumed the $PM_{2.5}/PM_{10}$ ratios were 1.0 for these sources.

The release parameters used in the CALPUFF simulations are shown in Table 5.1-26. The stack parameters for the gas turbines are based on the emission scenario that resulted in the majority of the higher short-term emission rates. This case assumes 100 percent load, a 20°F ambient temperature, and duct-firing from a new turbine (See Section 5.1.2). Emissions from the ten cooling tower cells were combined and simulated as a single source. The stack parameters for the combined cooling tower source were based on the average location of the ten cells and the exit characteristics of a single cell.

At the request of the FLMs, simulations were also performed including emissions from Unit 1, Unit 2, and associated sources. The emission rates and release parameters for these sources are shown in Table 5.1-27 and Table 5.1-28, respectively. Maximum emissions for these sources are based on maximum potential levels (EFSEC.2001-01 Amendment 2) with revisions to incorporate more up-to-date data on sulfur levels in the natural gas delivered to the Grays Harbor Energy Center site as described in Section 5.1.2. Maximum annual and short-term emissions from the gas turbines were calculated considering both start-up and maximum operating conditions. For the CALPUFF simulations, the PM_{10} emissions shown in Table 5.1-27 were divided into components using the same techniques as used for Unit 3, Unit 4, and associated sources. In addition, the SO_2 emissions used in the CALPUFF simulations were reduced from the rates shown in Table 5.1-27 to account for the sulfur emitted as ammonium sulfate.

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[8] The NPS recommendations are shown on http://www2.nature.nps.gov/air/permits/ect/ectGasFiredCT.cfm. This guidance is primarily based on (Corio, L.A., and J. Sherwell, 2000)

[9] USEPA website containing PM speciation by source categories: http://www.epa.gov/ttn/chief/emch/speciation.

TABLE 5.1-26
CALPUFF RELEASE PARAMETERS FOR AQRV ANALYSIS

Source	X (km) [a]	Y(km) [a]	Elevation (m) [b]	Release Height (m)	Exit Temp .(K)	Exit Velocity (m/s)	Stack Diameter (m)
HRSG Unit 3	-181.612	-215.428	74.5	54.9	344.7	20.2	5.486
HRSG Unit 4	-181.571	-215.431	74.5	54.9	344.7	20.2	5.486
Aux Boiler 2	-181.516	-215.443	74.6	14.9	476.5	20.8	0.536
Diesel Generator 2	-181.542	-215.431	74.5	4.0[d]	760.9	94.6	0.152
Fire Pump 2	-181.610	-215.406	74.3	4.0[d]	828.7	72.7	0.127
Cooling Towers [c]	-181.549	-215.376	74.0	15.8	312.0	5.4	12.980

a. Lambert conformal coordinates with an origin of 49N and 121W and standard latitudes of 30N and 60N.
b. Bilinear interpolated elevation from 4-km mesh size terrain file used in the CALPUFF simulations.
c. Cooling towers emissions were combined into a single source using the stack parameters of a single cooling tower cell.
d. The engine stack heights were increased following completion of the Class I area analyses; it is assumed that the increase (see Table 5.1-18) will not affect dispersion to distant receptors in regional Class I areas.

TABLE 5.1-27
EMISSION RATES FOR EXISTING UNIT 1 AND 2 SOURCES
(lbs/hr)

Source	Short-Term Emissions			Annual Emissions		
	SO_2	NO_X	PM_{10}	SO_2	NO_X	PM_{10}
HRSG Unit 1	12.836	27.785	22.603	7.053	27.785	22.603
HRSG Unit 2	12.836	27.785	22.603	7.053	27.785	22.603
Aux Boiler 1	0.169	1.030	0.292	0.107	0.297	0.292
Diesel Generator 1	0.273	7.055	0.220	0.016	0.403	0.013
Fire Pump 1	0.111	4.161	0.244	0.006	0.238	0.014
Cooling Towers	0.000	0.000	1.027	0.000	0.000	1.027

Ammonia and Ozone Background Concentrations

The NO_X chemistry in CALPUFF depends on the ambient ammonia concentration to establish the equilibrium between gaseous nitric acid and ammonium nitrate. However, ambient ammonia concentrations are not explicitly simulated by CALPUFF and the user must select an appropriate background level. The IWAQM Phase II Recommendations suggest typical ammonia concentrations are: 10 parts per billion (ppb) for grasslands, 0.5 ppb for forests, and 1 ppb for arid lands during warmer weather. These recommendations also suggest higher ammonia concentrations might be assumed in regions with dairy farms or where emissions of ammonia may be higher.

TABLE 5.1-28
CALPUFF RELEASE PARAMETERS FOR EXISTING UNIT 1 AND 2 SOURCES

Source	X (km) [a]	Y(km) [a]	Elevation (m) [b]	Release Height (m)	Exit Temp. (K)	Exit Velocity (m/s)	Stack Diameter (m)
HRSG Unit 1	-181.737	-215.402	74.2	54.9	356.0	20.1	5.486
HRSG Unit 2	-181.696	-215.404	74.2	54.9	356.0	20.1	5.486
Aux Boiler 1	-181.641	-215.416	74.4	14.9	476.5	19.3	0.536
Diesel Generator 1	-181.668	-215.404	74.2	4.0	914.8	49.0	0.152
Fire Pump 1	-181.720	-215.335	73.6	4.0	828.7	49.0	0.152
Cooling Towers [c]	-181.675	-215.316	73.4	15.8	312.0	9.3	9.906

a. Lambert conformal coordinates with an origin of 49N and 121W and standard latitudes of 30N and 60N.
b. Bilinear interpolated elevation from 4-km mesh size terrain file used in the CALPUFF simulations.
c. Cooling towers emissions were combined into a single source using the stack parameters of a single cooling tower cell.

The lowlands areas in western Washington and Oregon contain many areas where dairy farms and other sources cause ammonia emissions to be relatively higher than would be expected in other areas of the United States. For Class I area assessments in western Washington and Oregon it has become a common practice to assume a conservative ammonia background concentration of 17 ppb. This conservative concentration was recommended for Pacific Northwest BART simulations and is based on measurements in southern British Columbia. This relatively high background ensures the conversion of NO_X to ammonium nitrate is not limited by a lack of ammonia for the range of NO_X concentrations predicted in this study.

Reaction rates in the CALPUFF chemistry algorithms are also influenced by background ozone concentrations. At the request of the USFS, a background ozone concentration of 60 ppb was assumed for all simulations (R. Graw, personal communication 2008). The USFS recommended ozone concentration was derived by Ecology using available ozone monitoring data from the Pacific Northwest for CALPUFF simulations to assess BART. Sixty ppb represents the 98th percentile of the database analyzed by Ecology.

Meteorological Data

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 the USEPA 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.

CALMET (Version 5.8), the meteorological preprocessor component of the CALPUFF system, was used to combine the MM5 simulation data, surface observations, terrain elevations, and land

use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer parameters used to characterize diffusion and deposition by the dispersion model.

The techniques used to construct the meteorological database follow the recent May 2009 draft guidance from the USEPA and the FLMs (USEPA et al. 2009). This guidance describes recommended techniques to blend the UW MM5 simulations with surface, upper-air, overwater, and precipitation observations using CALMET. Major features of the CALMET application and input data preparation are as follows:

- The model domain is a subset of the UW's 4-km mesh size MM5 domain as shown in Figure 5.1-3. The horizontal mesh size is 4 km, with each CALMET grid point matched to a MM5 grid point. In order to match the MM5 simulations, a Lambert Conformal Conic (LCC) coordinate system was used with an origin of 49N, 121W and standard latitudes of 30N and 60N. Twenty-four vertical levels ranging geometrically from the surface to 4,270 m were selected to match the levels used by MM5.

- MM5 winds based on a 4-km grid spacing for January 2003 to December 2005 were used to initialize the three-dimensional wind field predictions. The MM5 data were processed with the CALMM5 utility for use by CALMET.

- Land use and terrain data were prepared using the processing tools accompanying the CALPUFF modeling system and the USGS GTOPO30 elevation data sets available on the Internet. Figure 5.1-5 shows the 4-km mesh size terrain used in the simulations.

- Surface weather observations were extracted from the National Climatic Data Center (NCDC) Integrated Surface Hourly Observations (ISHO) dataset (TD-3505) for an area that extended 50 km beyond the study domain boundary. Depending on the year, between 69 and 73 surface stations were processed for use by CALMET.

- Twice daily upper air soundings from seven sites in southwest Canada and the Pacific Northwest were blended with the MM5 data for upper level winds, temperatures and lapse rates.

- Buoy observations from twenty stations off the Pacific Coast from northern California to Southern British Columbia were obtained from the National Data Buoy Center. These data are used by CALMET to characterize winds, sea-air temperature differences, and air temperatures over marine areas of the domain. The buoy data were processed by the BUOY utility from the CALPUFF modeling system.

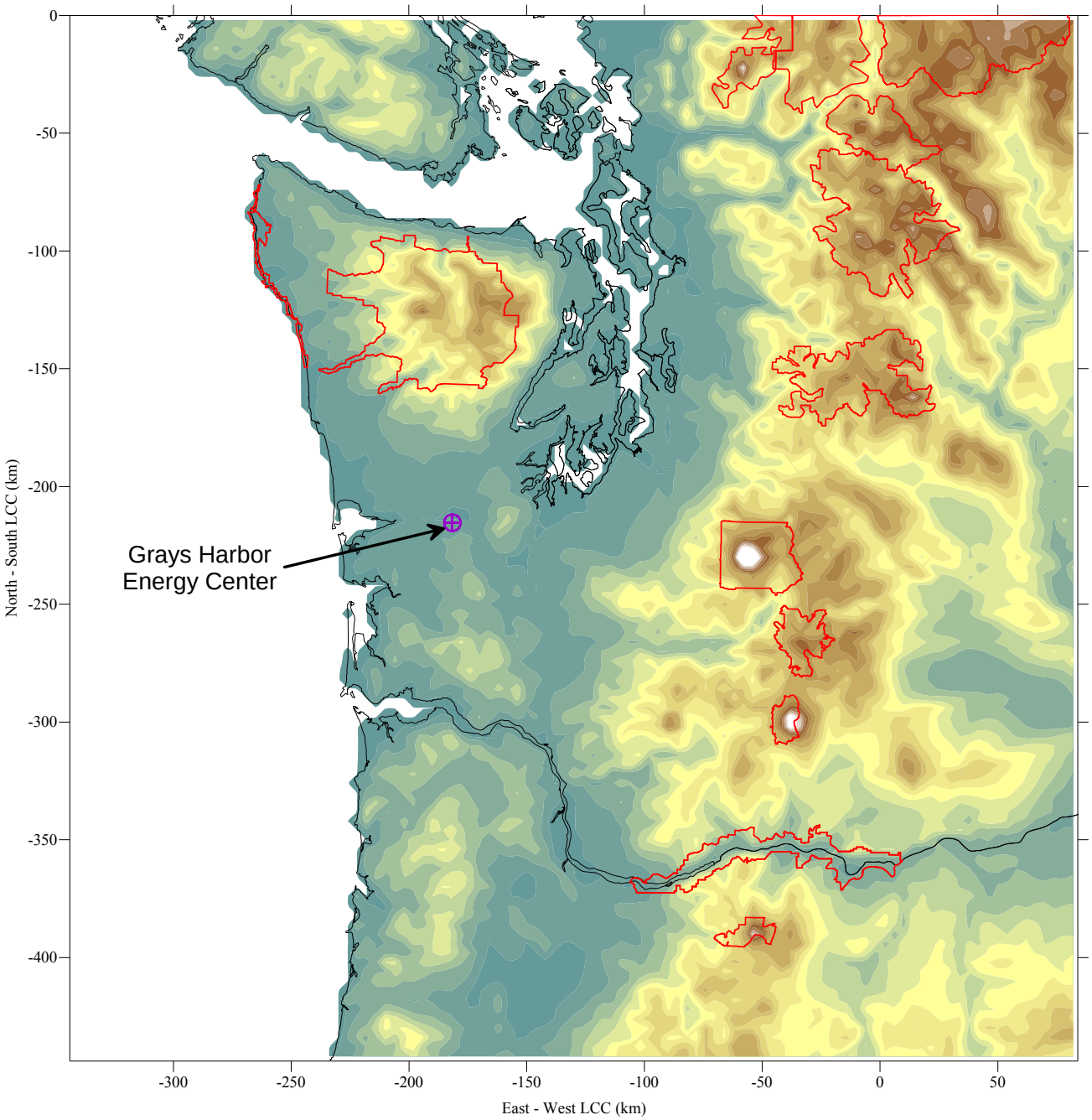

Figure 5.1-5
CALMET 4-km Mesh Size Terrain

- Hourly precipitation data were obtained from the NCDC's TD-3240 (COOP) dataset and processed with the CALMET utility PMERGE. Sites were selected based on the criteria that the locations must be near (within 50 km) or in the model domain and there must be at least a 50 percent data recovery. Using these criteria, historic precipitation data from this dataset are available for between 58 to 84 stations depending upon the year.

- The CALMET interpolation option variables used to blend the MM5 initial fields with the surface, precipitation, buoy, and upper air observations follow the recent revised recommendations of the USEPA and FLMs (USEPA et al. 2009). A sample CALMET input file was submitted to the NPS and subsequently approved as part of their review of the modeling protocol (J. Notar, personal communication).

Selected hours of the three-year CALMET/MM5 three-dimensional data set were examined by extracting data from the CALMET output files and plotting the meteorological fields with the CALDESK software package. Wind vector plots were examined for different times of year, different times of day, and for all 24 vertical levels.

Elevation Data and Receptor Network

The CALPUFF dispersion model simulations assessed AQRVs at discrete receptors within each Class I area using the receptor locations and elevations provided by the NPS.[10] In addition to the discrete receptors, a receptor grid with 4-km spacing was also used throughout the CALPUFF modeling domain for AQRV predictions. The 4-km mesh size receptors were used to construct plots showing the spatial variation of the calculated parameters throughout the modeling domain. Such plots were used for diagnostic purposes, to develop the figures presented in this PSD application to EFSEC, and to provide the usually requested spatial information for the FLMs review.

The NPS receptor files do not include the CRGNSA. Receptor locations within the CRGNSA were based on a 2-km mesh. These receptors were added to the NPS discrete receptors in the simulations. Terrain elevations for the receptors within the CRGNSA were based on bi-linear interpolation from the CALMET 4-km mesh size terrain.

AQRV Calculation Procedures

The CALPUFF modeling system was used to predict criteria pollutant concentrations, total deposition fluxes, and light extinction coefficients attributable to project emissions in regional Class I areas. These parameters were calculated from CALPUFF output files using the post-processor programs CALPOST and POSTUTIL.

Predictions of NO_X, SO_2, and PM_{10} concentrations in the Class I areas of interest were extracted from the annual and 24-hour emission cases using the CALPOST post-processor. PM_{10}

[10] The NPS receptors can be found at http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm.

concentration estimates include both primary and secondary aerosols and account for the molecular weights of each resulting compound. The conversion to account for molecular weight and summing of species are accomplished using the POSTUTIL processor. Total nitrogen and sulfur deposition fluxes are similarly calculated by summing and converting the various species included in the wet and dry deposition CALPUFF output files. The nitrogen deposition fluxes include the nitrogen from the background ammonia to some extent. For comparison to FLM deposition criteria, the fluxes were converted to kilograms per hectare per year.

The potential impacts of emissions from Units 3 and 4 sources to regional haze in the Class I areas of interest and the CRGNSA were assessed using predictions of the 24-hour change to extinction. The FLMs recommend in the FLAG Phase I Report that a five percent change to extinction be used to indicate a "just perceptible" change to a landscape. CALPOST was used to calculate both the extinction coefficient attributable to the proposed emission increases as well as the background extinction coefficients. Specifically:

- Extinction coefficients were calculated using hourly predicted aerosol concentrations, hourly relative humidity, and background aerosol concentrations with CALPOST Method 2 (MVISBK = 2). Relative humidly was capped at 95 percent (RHMAX=95) and the FLAG relative humidity growth factors were applied to the hygroscopic aerosols (MFRH=2).

- Default light extinction scattering efficiencies were used for each aerosol species.

- Background visibility in all Class I areas of interest were based on the FLAG defaults for the western US by using the hygroscopic (0.6 Mm-1), dry (4.5 Mm-1), and Rayleigh scattering (10.0 Mm-1) portions of the extinction coefficient. These defaults were applied within CALPOST during post-processing with the following options: BKSO4=0.2, BKSOIL=4.5 and BEXTRAY=10.

The current FLAG recommended CALPOST method for extinction coefficients can be very sensitive to hourly relative humidity. High relative humidity in the Pacific Northwest is often associated with precipitation, fog, low overcast and weather related visibility obscuring phenomena. In order to provide the FLMs with further information, extinction coefficients were calculated using the 2008 proposed revisions to the FLM FLAG procedures. The revised procedures employ an updated equation for extinction (invoked with MVISCHECK=1) using monthly relatively humidity adjustment factors and annual background aerosol concentrations recommended by the FLMs for each Class I area.[11] In order to use this method, CALPOST Version 6.221 (Level 080724) was used to post-process the CALPUFF output files.

[11] The necessary monthly relatively humidity adjustment factors and background aerosol concentrations for the CRGNSA were assumed to be the same as recommended for the Mt. Hood Wilderness.

AQRV Modeling Results

The CALPUFF modeling system was used to predict concentrations of NO_X, SO_2, and PM_{10} in regional Class I areas and the CRGNSA using the three year regional meteorological data set. Three annual simulations were performed in parallel for each of the three years (2003-2005). In order to account for plumes that may remain within the domain at the end of the year, the simulations for 2004 and 2005 were started two weeks early. The CALPUFF simulations used the Unit 3, Unit 4, and associated source emission rates presented in Table 5.1-24 and Table 5.1-25, and the source release parameters shown in Table 5.1-26. To provide additional information to the FLMs, cumulative simulations were also performed that included emissions from Unit 1, Unit 2, and associated sources (Table 5.1-27). The resulting CALPUFF output files were post-processed to extract the necessary variables for comparison with the FLM Class I AQRV criteria.

Criteria Pollutant Concentrations

Table 5.1-29 summarizes the predicted maximum criteria pollutant concentrations and compares them to the Class I SILs[12] 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). As shown in Table 5.1-29, the CALPUFF simulations indicate criteria pollutant concentrations attributable to Unit 3, Unit 4 and associated sources are less than the Class I SILs and the increments in all Class I areas and the CRGNSA.

Contour plots of model predicted maximum concentrations were constructed for several of the applicable pollutants and averaging periods to examine the spatial variation of the predictions across the study domain. Figures 5.1-6 and Figure 5.1-7 present the predicted maximum concentrations for 24-hour PM_{10} and annual NO_X. The annual predictions tend to follow the Chehalis River Valley near the site, extending northeast into the Puget Sound lowlands, and southeast towards the Willamette Valley. The contours also show the influence of regional flow out the mouth of the Chehalis River near Aberdeen. The maximum PM_{10} predictions for the shorter 24-hour averaging period occur close to the Grays Harbor Energy Center site and are less influenced by the prevailing regional wind patterns. In general the higher concentrations tend to occur at terrain elevations lower than in the Class I areas as the Grays Harbor Energy Center plumes are usually confined to the boundary layer and winds are diverted around the more mountainous areas of the domain.

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[12] Currently there are two sets of Class I SILs, those proposed by USEPA 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.

TABLE 5.1-29
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	0.0392	0.0023	0.0205	0.0068	0.0003
Glacier Peak WA	0.0001	0.0199	0.0012	0.0089	0.0031	0.0001
Goat Rocks WA	0.0002	0.0238	0.0013	0.0185	0.0055	0.0001
Mt. Adams WA	0.0001	0.0146	0.0009	0.0175	0.0033	0.0001
Mt. Hood WA	0.0000	0.0244	0.0006	0.0060	0.0031	0.0001
Mt. Rainier NP	0.0006	0.0619	0.0029	0.0291	0.0099	0.0004
Olympic NP	0.0018	0.1074	0.0044	0.1596	0.0313	0.0007
Columbia River Gorge [b]	0.0002	0.0287	0.0012	0.0145	0.0048	0.0001
Class I Area Max. Conc. [b]	0.0018	0.1074	0.0044	0.1596	0.0313	0.0007
USEPA 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 percent 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; USEPA proposed and FLM 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 5.1-30 summarizes the results for the simulations that included emissions for existing Unit 1 and 2 emission units. 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 sources. Since according to regulatory guidance PSD increment consumption from existing sources is based on actual emissions, the results shown in Table 5.1-30 grossly overstate increment consumption attributable to Grays Harbor Energy Center cumulative source emissions.

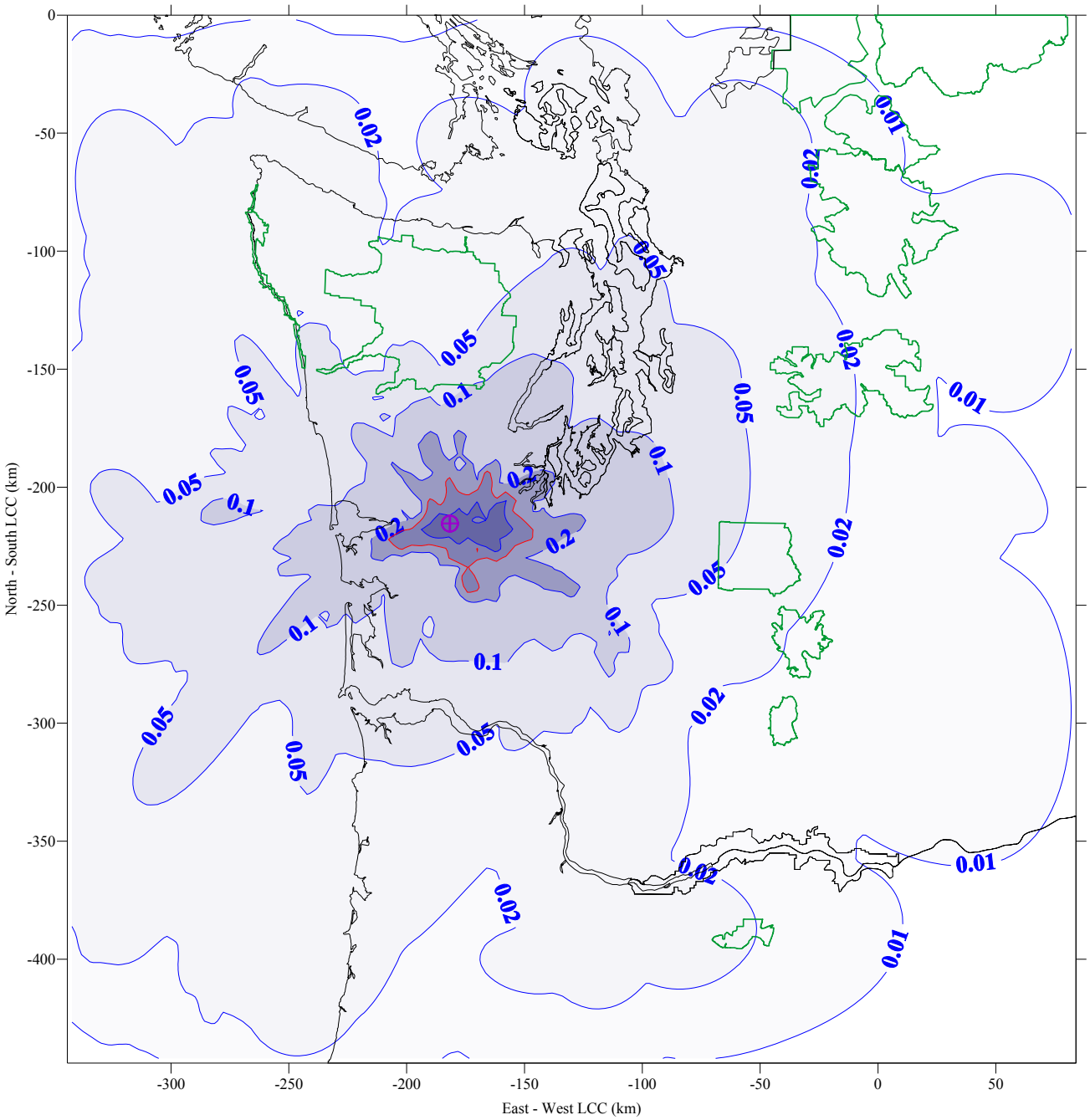

Figure 5.1-6
Maximum Predicted 24-hour PM_{10} Concentrations ($\mu g/m^3$)

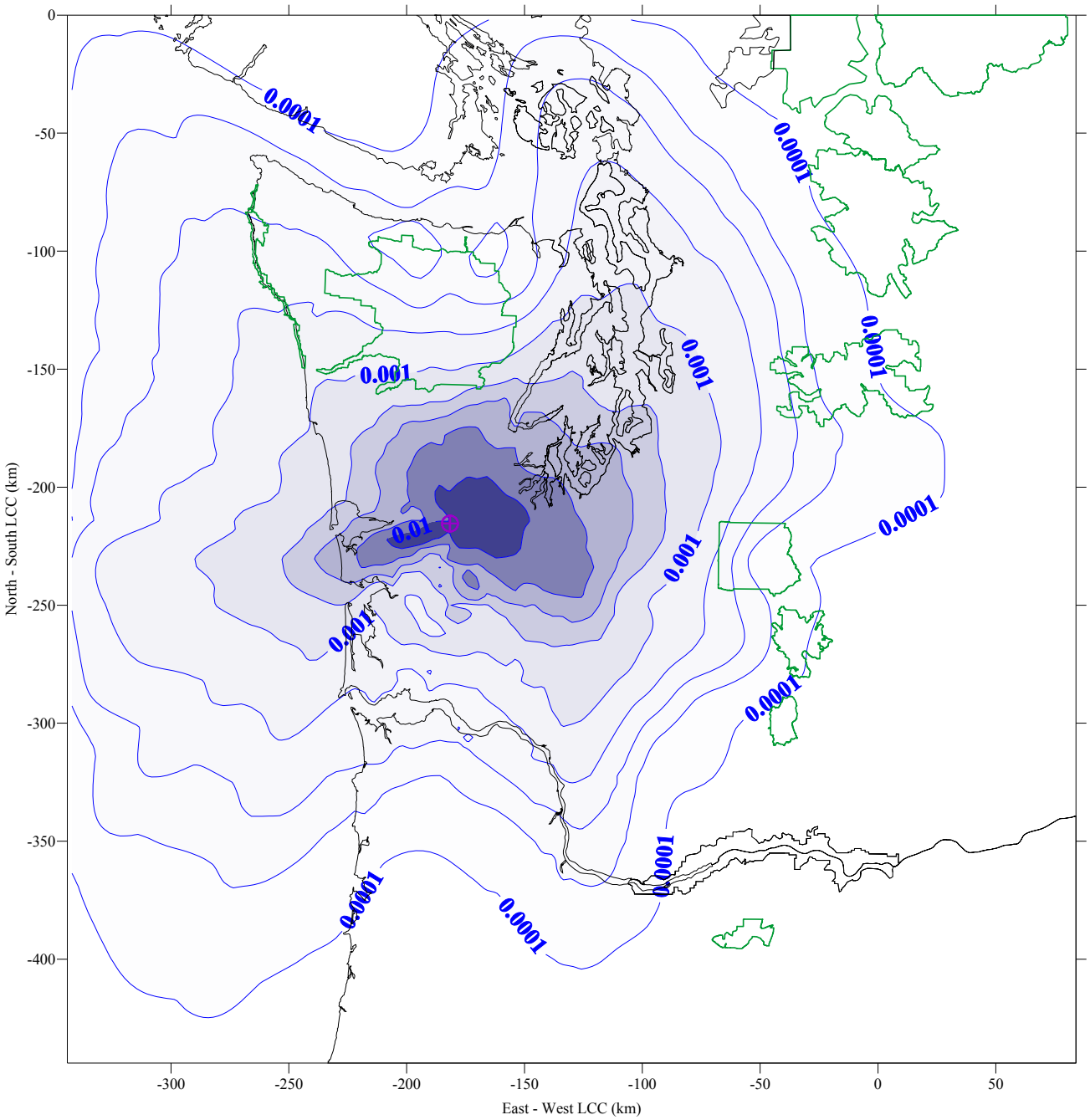

Figure 5.1-7
Maximum Predicted Annual NO_x Concentrations ($\mu g/m^3$)

TABLE 5.1-30
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	0.0852	0.0052	0.0403	0.0135	0.0006
Glacier Peak WA	0.0003	0.0428	0.0027	0.0175	0.0059	0.0003
Goat Rocks WA	0.0005	0.0508	0.0029	0.0364	0.0111	0.0003
Mt. Adams WA	0.0002	0.0314	0.0019	0.0344	0.0064	0.0002
Mt. Hood WA	0.0001	0.0523	0.0013	0.0117	0.0062	0.0001
Mt. Rainier NP	0.0014	0.1316	0.0064	0.0571	0.0193	0.0008
Olympic NP	0.0042	0.2287	0.0097	0.3151	0.0617	0.0014
Columbia River Gorge [b]	0.0004	0.0617	0.0027	0.0292	0.0096	0.0003
Class I Area Max. Conc.[b]	0.0042	0.2287	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 percent 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).

Nitrogen and Sulfur Deposition Fluxes

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).[13] 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 5.1-31 where the maximum annual predictions for each Class I area and the CRGNSA are compared to the NPS nitrogen and sulfur DATs. Figure 5.1-8 and Figure 5.1-9 show the respective spatial variation of the maximum annual predicted sulfur and nitrogen deposition fluxes attributable to Units 3 and 4 sources over the entire simulation domain. General regional flow tends to direct plumes from the facility away from the Class I areas.

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

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

TABLE 5.1-31
PREDICTED CLASS I AREA AND CRGNSA DEPOSITION FLUXES
(kg/ha/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 5.1-32 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.

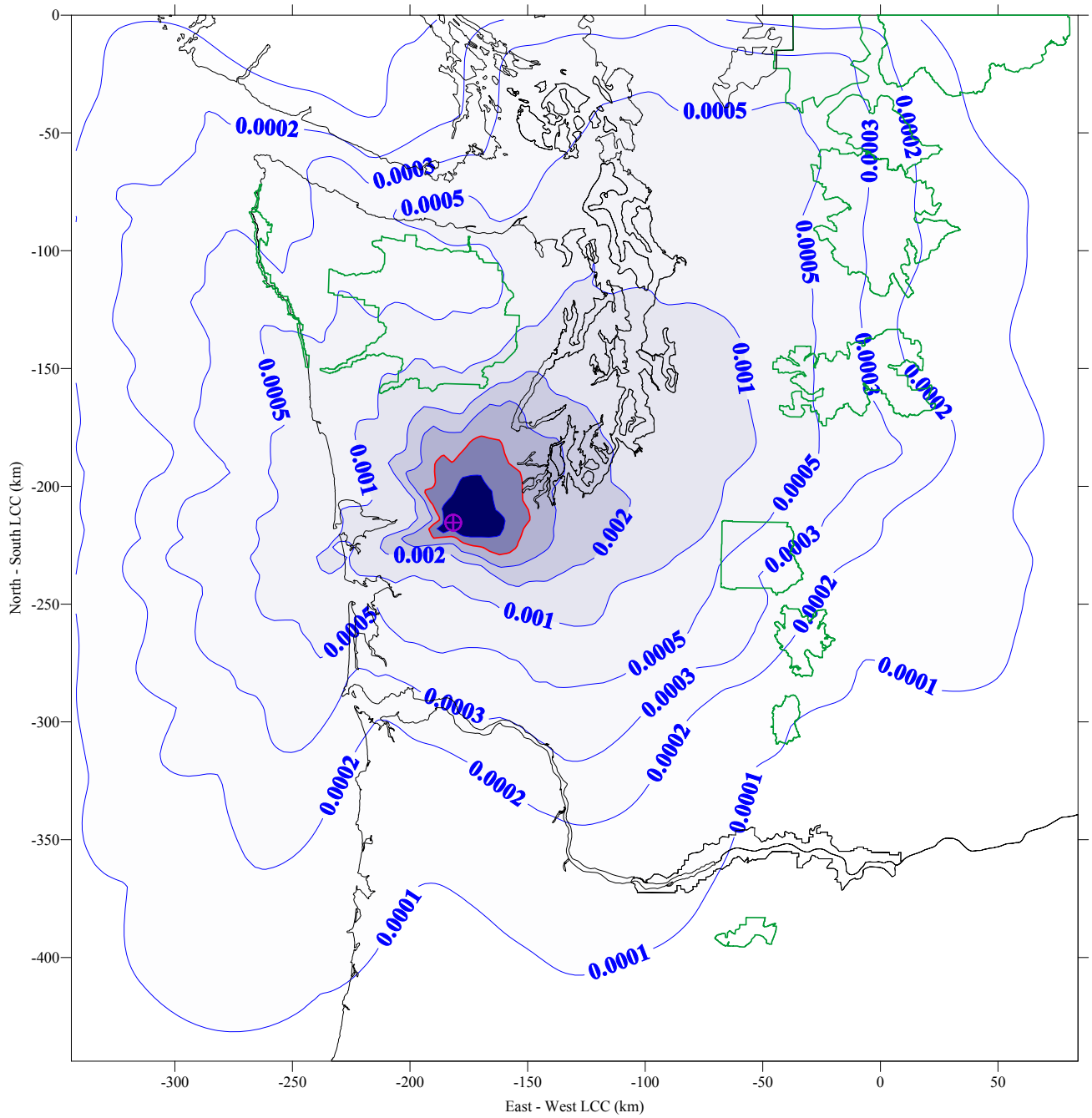

Figure 5.1-8
Maximum Predicted Annual Sulfur Deposition Fluxes (kg/ha/yr)

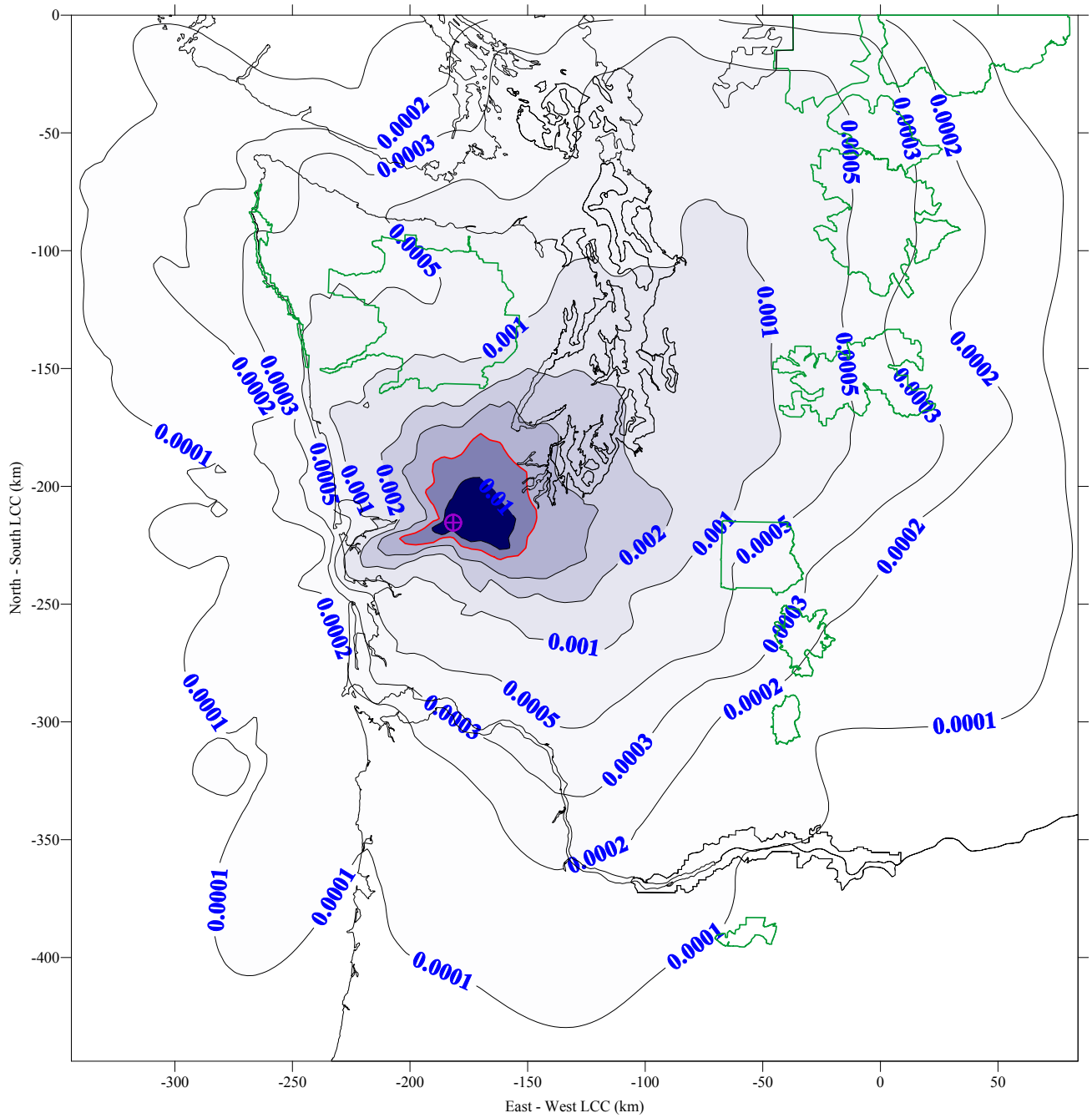

Figure 5.1-9
Maximum Predicted Annual Nitrogen Deposition Fluxes (kg/ha/yr)

TABLE 5.1-32
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.

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). The new equation considers sea salt, nitrogen dioxide, Rayleigh scattering the varies with elevation, monthly relative humidity adjustment factors and other changes intended to refine the estimates for each Class I area. In the discussion the follows this technique will be referred to as CALPOST Method 8.

Regional haze within the CRGNSA was assessed using the same methods as the Class I areas. For CALPOST Method 2, the background aerosol concentrations were based on the FLAG defaults representative of "natural" conditions for western US. Recommendations for the Mt. Hood Wilderness were used for CALPOST Method 8.

The ten days with the highest maximum predicted changes in 24-hour extinction in three years using CALPOST Method 2 are identified in Table 5.1-33. Table 5.1-34 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 5.1-33 and Table 5.1-34 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.

Figure 5.1-10 displays a time series plot of the maximum daily change to extinction for Olympic National Park, Mt. Rainier National Park and the Alpine Lakes Wilderness predicted using CALPOST Method 2. With the exception of the highest day on May 8, 2004, many of the days with the highest change to extinction predicted for Olympic National Park tend to occur during the winters months. These higher days are characterized by light winds and high relative humidity. The seasonal behavior predicted for the Mt. Rainier National Park and the Alpine Lakes Wilderness differs with the highest events predicted during the summer and fall months. During fair weather in the winter, plumes from Unit 3 and 4 sources tend to be embedded in easterly flow and/or remain in the lowlands. Class I areas in the Cascade Mountains are only potentially affected under westerly flow. Westerly winds combined with less favorable dispersive conditions occur more often during the summer and fall months.

Figure 5.1-11 shows contours of the maximum predicted 24-hour extinction in three years due to emissions from the Unit 3 and 4 sources using CALPOST Method 2. The highest 24-hour extinction coefficients occur close to the Grays Harbor Energy Center in the Black Hills, east of the site. The higher extinction coefficients close to the site are primarily driven by the sulfate and elemental carbon aerosols directly emitted as PM_{10} from the plant. Secondary aerosols formation becomes more import with distance from the site and the higher extinction coefficients occur in the lowlands. Conditions favorable for aerosol formation and high relative concentrations are light winds, high humidity and fair weather. During these conditions, high pressure and subsidence inversions are sometimes present to restrict the vertical movement of the fine particles. Aerosols remain trapped until a precipitation event removes them or until winds increase sufficient to allow vertical mixing and transport out of the lowlands.

TABLE 5.1-33
TEN DAYS WITH MAXIMUM PREDICTED CLASS I AREA 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	1.982	17.487	19.469	11.33	4.98	1.095	0.607	0.086	0.194	0.000	0.000
Olympic NP	11/22/03	1.462	18.563	20.025	7.88	6.77	0.599	0.665	0.061	0.137	0.000	0.001
Olympic NP	01/17/04	1.473	19.866	21.339	7.42	8.94	0.852	0.404	0.067	0.150	0.000	0.001
Olympic NP	11/21/03	1.207	18.433	19.640	6.55	6.56	0.428	0.578	0.062	0.138	0.000	0.001
Olympic NP	07/22/05	1.051	16.839	17.890	6.24	3.90	0.493	0.384	0.053	0.120	0.000	0.000
Olympic NP	12/18/04	1.171	19.805	20.976	5.91	8.84	0.529	0.498	0.044	0.099	0.000	0.001
Olympic NP	01/07/03	0.893	18.279	19.172	4.88	6.30	0.518	0.221	0.047	0.106	0.000	0.000
Olympic NP	01/28/03	0.924	19.780	20.704	4.67	8.80	0.433	0.367	0.038	0.085	0.000	0.001
Mt. Rainier NP	10/05/03	0.790	17.503	18.293	4.52	5.01	0.342	0.325	0.038	0.085	0.000	0.001
Olympic NP	11/14/03	0.880	20.105	20.985	4.38	9.34	0.468	0.288	0.038	0.086	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.

TABLE 5.1-34
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	0.714	19.343	20.057	3.69	8.072	0.340	0.290	0.026	0.058	0.000	0.001
Glacier Peak WA	11/22/04	0.358	19.496	19.853	1.84	8.326	0.156	0.160	0.013	0.029	0.000	0.000
Goat Rocks WA	02/28/04	0.282	16.855	17.137	1.67	3.926	0.120	0.123	0.012	0.027	0.000	0.000
Mt. Adams WA	05/18/03	0.147	16.109	16.256	0.91	2.682	0.066	0.048	0.010	0.023	0.000	0.000
Mt. Hood WA	09/17/05	0.227	17.015	17.242	1.34	4.192	0.092	0.103	0.010	0.022	0.000	0.000
Mt. Rainier NP	10/05/03	0.790	17.503	18.293	4.52	5.005	0.342	0.325	0.038	0.085	0.000	0.001
Olympic NP	05/08/04	1.982	17.487	19.469	11.33	4.978	1.095	0.607	0.086	0.194	0.000	0.000
Columbia River Gorge [d]	09/17/05	0.461	17.027	17.488	2.71	4.211	0.190	0.211	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.

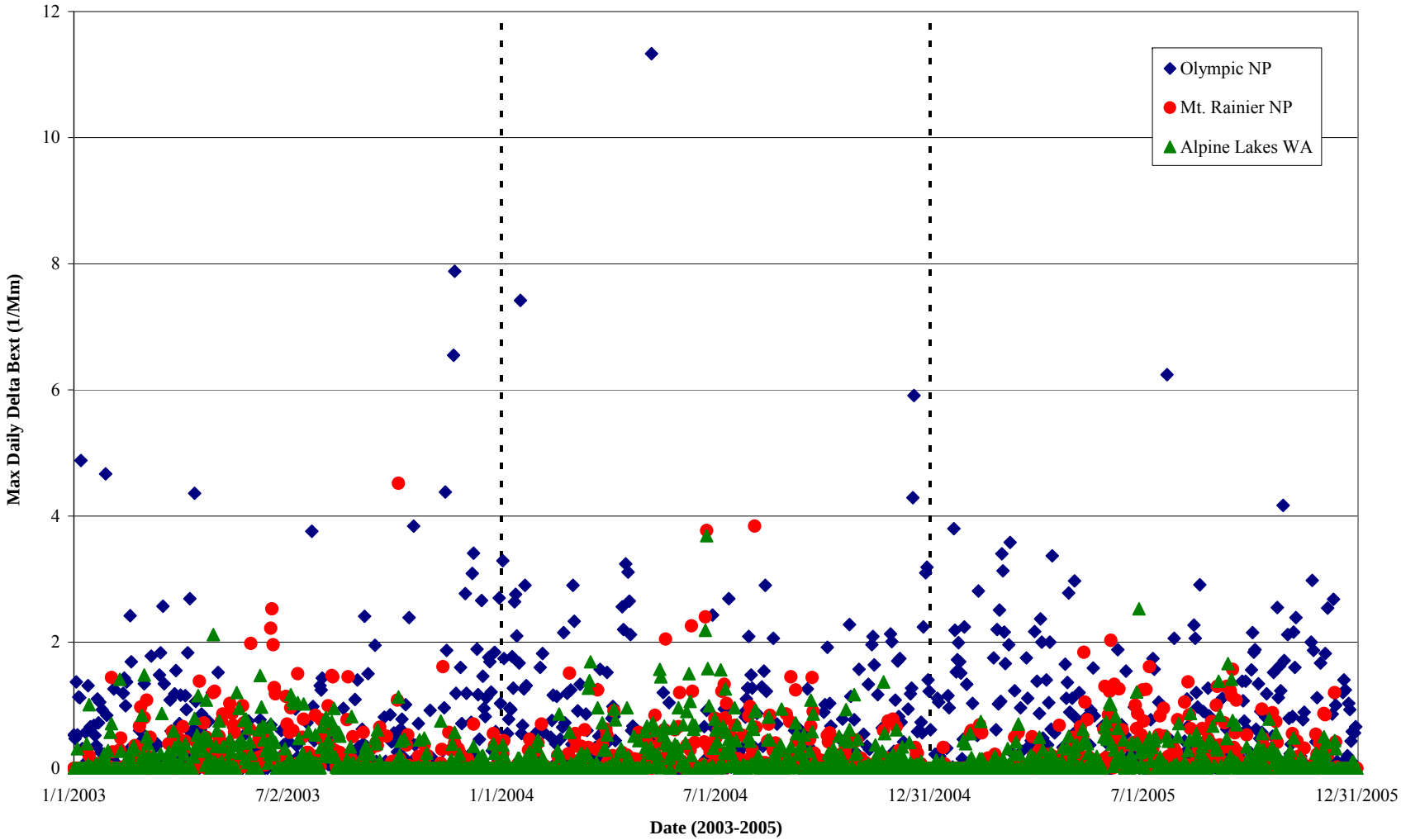

Figure 5.1-10
Time Series of Maximum Daily Change to Extinction for Selected Class I Areas Using CALPOST Method 2

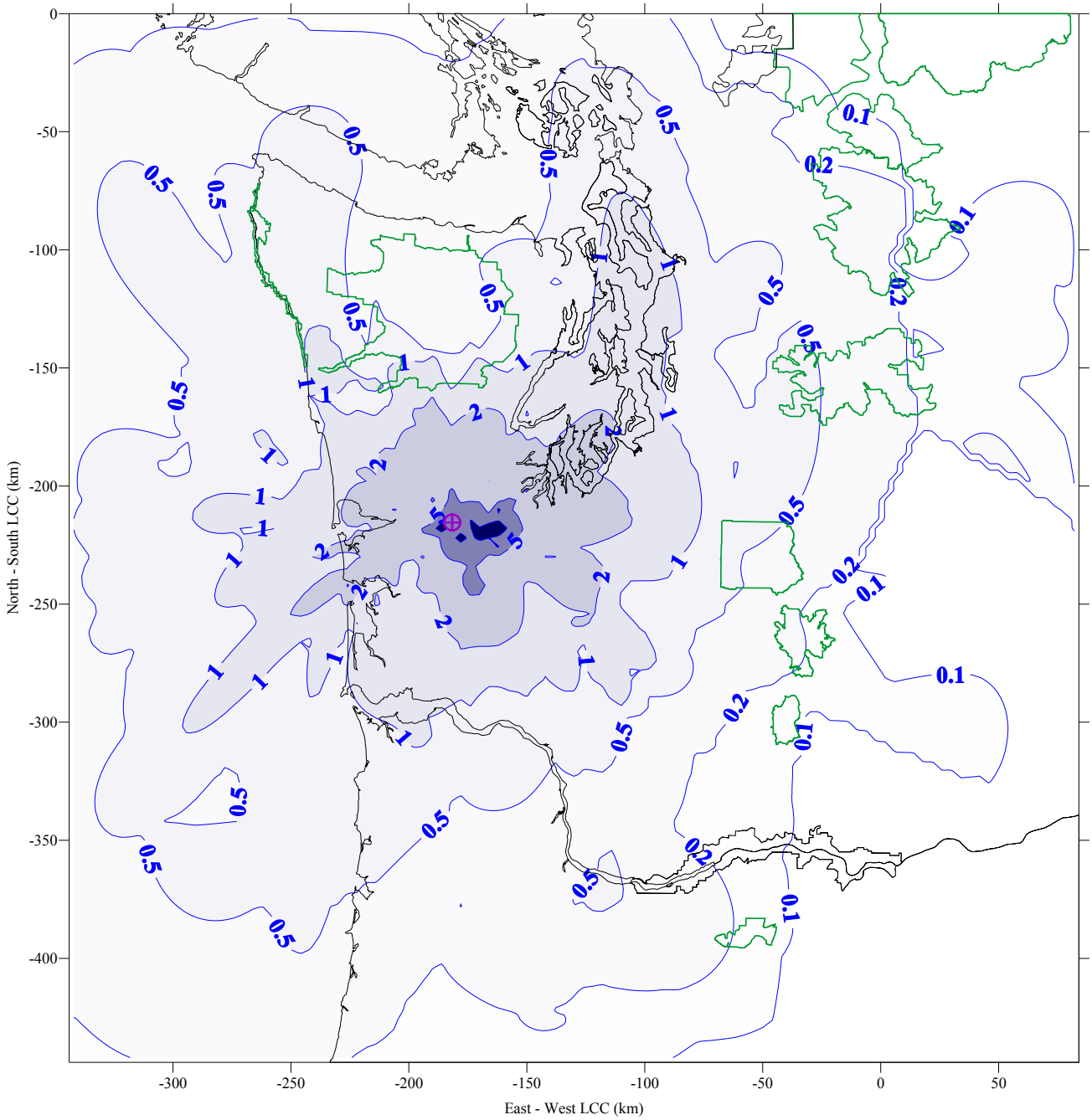

Figure 5.1-11
Maximum Predicted Extinction Coefficient (1/Mm) from/to Grays Harbor Energy Center based on CALPOST Method 2

Figure 5.1-12 presents a contour plot of the predicted change to extinction caused by emissions attributable to the Unit 3 and 4 sources on the day (May 8, 2004) predicted to experience the maximum change in extinction in the Olympic National Park.[14] The episode affecting Olympic National Park occurs during a period of transition from easterly to southwesterly regional flow, resulting in net transport to the north from the site. Light winds were prevalent throughout the day, with cool temperatures and high humidity in the mornings and late evening hours. Fog was reported in Olympia, Shelton and Hoquiam on this day.

The FLMs recommend in the FLAG Phase I Report that a five percent change in extinction indicates a "just perceptible" change to a landscape. As shown in Table 5.1-33, this screening criterion is predicted to be exceeded on six days in the three year simulation using CALPOST Method 2. All these events are predicted for the Olympic National Park and potential changes to extinction are less than five percent for the other Class I areas and CRGNSA.

Although the predicted change to extinction in south boundary of Olympic National Park exceeds the FLM criteria of five percent on six days in three years, increased emissions from Unit 3 and 4 sources are not expected to significantly degrade visibility due to the inherent conservatism in the CALPOST Method 2 approach. The Method 2 techniques are very sensitive to hourly relative humidity that is often caused by inclement weather that naturally obscures visibility.

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 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 seas salt, distinguishes between small and large hygroscopic particles, varies Rayleigh scatterings 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 humidifies that accompany rain and fog.

The ten days with the highest predicted changes in 24-hour extinction in three years using CALPOST Method 8 are identified in Table 5.1-35. Table 5.1-36 lists the highest prediction in each Class I area and in the CRGNSA. Using this technique only two days in the three 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.

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[14] The contour plot in Figure 5.1-12 was prepared from the results at gridded receptor locations. In order to prepare a plot for the entire domain, it was necessary to select a single set of background aerosol concentrations. The changes to extinction in this figure are based on the FLAG western US defaults for "natural" conditions. The results shown were developed using CALPOST Method 2.

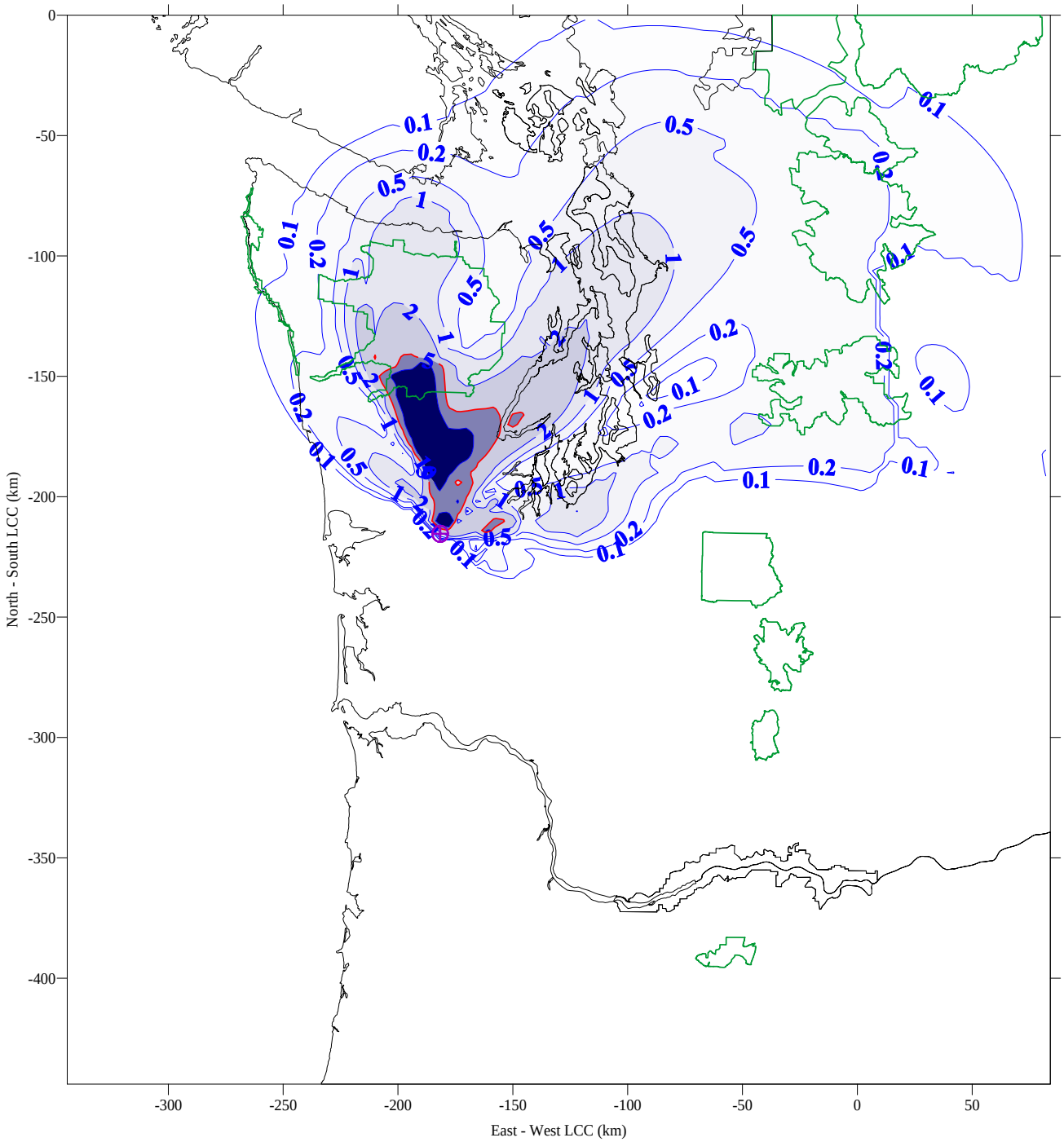

Figure 5.1-12
Predicted Change to the Extinction Coefficient (%) on May 8, 2004 based on CALPOST Method 2

TABLE 5.1-35
TEN DAYS WITH MAXIMUM PREDICTED CLASS I AREA AND CRGNSA EXTINCTION CHANGE PREDICTED WITH CALPOST METHOD 8
(1/Mm)

Area [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
olna	11/21/03	1.278	18.615	19.894	6.87	0.440	0.652	0.046	0.138	0.000	0.001	0.000	6.11	3.99	5.51
olna	11/22/03	1.143	18.615	19.758	6.14	0.417	0.539	0.046	0.137	0.000	0.001	0.003	6.11	3.99	5.51
olna	05/08/04	0.781	17.081	17.862	4.57	0.316	0.190	0.065	0.194	0.000	0.000	0.017	3.81	2.76	3.94
olna	01/17/04	0.796	18.381	19.178	4.33	0.382	0.200	0.050	0.151	0.000	0.001	0.011	5.76	3.80	5.27
olna	12/18/04	0.692	18.558	19.250	3.73	0.274	0.282	0.033	0.099	0.000	0.001	0.004	6.02	3.95	5.46
mora	10/05/03	0.666	17.946	18.612	3.71	0.278	0.274	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	07/23/03	0.622	16.892	17.514	3.68	0.225	0.213	0.045	0.135	0.000	0.001	0.003	3.52	2.61	3.76
olna	03/02/04	0.651	17.745	18.396	3.67	0.233	0.293	0.031	0.092	0.000	0.001	0.001	4.81	3.30	4.61
olna	01/28/03	0.594	18.381	18.976	3.23	0.241	0.235	0.029	0.085	0.000	0.001	0.003	5.76	3.80	5.27
olna	04/14/03	0.556	17.636	18.192	3.15	0.250	0.131	0.041	0.124	0.000	0.001	0.009	4.64	3.21	4.51

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, NOx = 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 5.1-36
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	0.387	17.201	17.587	2.25	0.158	0.163	0.016	0.049	0.000	0.000	0.000	5.43	3.60	4.98
glpe	11/22/04	0.220	16.904	17.124	1.30	0.085	0.096	0.010	0.029	0.000	0.000	0.000	5.80	3.83	5.31
goro	10/05/03	0.245	15.791	16.036	1.55	0.103	0.099	0.011	0.032	0.000	0.000	0.000	5.22	3.49	4.83
moad	02/27/03	0.146	15.676	15.822	0.93	0.050	0.071	0.006	0.019	0.000	0.000	0.000	5.00	3.40	4.74
moho	09/26/04	0.192	15.415	15.607	1.25	0.074	0.071	0.012	0.036	0.000	0.000	0.000	3.79	2.72	3.78
mora	10/05/03	0.666	17.946	18.612	3.71	0.278	0.274	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	11/21/03	1.278	18.615	19.894	6.87	0.440	0.652	0.046	0.138	0.000	0.001	0.000	6.11	3.99	5.51
xcrg	10/02/03	0.240	16.065	16.306	1.50	0.089	0.103	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 = crustal mass, NOx = 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 5.1-37 shows the number of days exceeding the five percentile 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 2.8 percent predicted 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.

Although a cumulative visibility analysis is not required based on the analysis above, at the request of the FLMs extinction coefficients were also calculated from simulations that included emissions from existing Unit 1 and 2 sources. The resulting ten days with the highest maximum predicted changes in 24-hour extinction in three years using CALPOST Method 8 are identified in Table 5.1-38. Table 5.1-39 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, 20 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 5.8 percent.

5.1.5 ADDITIONAL IMPACT ANALYSIS

5.1.5.1 Class II Area Growth

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. Its 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.

TABLE 5.1-37
PREDICTED 98TH PERCENTILE AND NUMBER OF DAYS WITH EXTINCTION CHANGE GREATER THAN FIVE PERCENT 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	1.13	0	0.79	0
	2004	1.45	0	0.82	0
	2005	0.87	0	0.66	0
Glacier Peak WA	2003	0.47	0	0.41	0
	2004	0.75	0	0.53	0
	2005	0.47	0	0.38	0
Goat Rocks WA	2003	0.91	0	0.64	0
	2004	0.74	0	0.60	0
	2005	0.72	0	0.64	0
Mt. Adams WA	2003	0.44	0	0.41	0
	2004	0.47	0	0.36	0
	2005	0.44	0	0.47	0
Mt. Hood WA	2003	0.38	0	0.35	0
	2004	0.58	0	0.42	0
	2005	0.40	0	0.33	0
Mt. Rainier NP	2003	1.47	0	1.03	0
	2004	1.44	0	0.90	0
	2005	1.30	0	1.18	0
Olympic NP	2003	3.76	2	2.81	2
	2004	3.11	3	2.28	0
	2005	2.98	1	2.25	0
Columbia River Gorge	2003	0.71	0	0.62	0
	2004	1.07	0	0.76	0
	2005	0.74	0	0.70	0

TABLE 5.1-38
MAXIMUM PREDICTED EXTINCTION CHANGE BY CLASS I AREA AND CRGNSA
PREDICTED WITH CALPOST METHOD 8 INCLUDING GRAYS HARBOR ENERGY CENTER EXISTING SOURCES
(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	0.387	17.201	17.587	2.25	0.158	0.163	0.016	0.049	0.000	0.000	0.000	5.43	3.60	4.98
glpe	11/22/04	0.220	16.904	17.124	1.30	0.085	0.096	0.010	0.029	0.000	0.000	0.000	5.80	3.83	5.31
goro	10/05/03	0.245	15.791	16.036	1.55	0.103	0.099	0.011	0.032	0.000	0.000	0.000	5.22	3.49	4.83
moad	02/27/03	0.146	15.676	15.822	0.93	0.050	0.071	0.006	0.019	0.000	0.000	0.000	5.00	3.40	4.74
moho	09/26/04	0.192	15.415	15.607	1.25	0.074	0.071	0.012	0.036	0.000	0.000	0.000	3.79	2.72	3.78
mora	10/05/03	0.666	17.946	18.612	3.71	0.278	0.274	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	11/21/03	1.278	18.615	19.894	6.87	0.440	0.652	0.046	0.138	0.000	0.001	0.000	6.11	3.99	5.51
xcrg	10/02/03	0.240	16.065	16.306	1.50	0.089	0.103	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 = crustal mass, NOx = 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 5.1-39
PREDICTED 98TH PERCENTILE AND NUMBER OF DAYS WITH EXTINCTION CHANGE GREATER THAN FIVE PERCENT USING CALPOST METHOD 8 INCLUDING GRAYS HARBOR ENERGY CENTER EXISTING SOURCES

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	1.68	0
	2004	1.77	0
	2005	1.41	0
Glacier Peak WA	2003	0.87	0
	2004	1.15	0
	2005	0.80	0
Goat Rocks WA	2003	1.28	0
	2004	1.27	0
	2005	1.34	0
Mt. Adams WA	2003	0.86	0
	2004	0.77	0
	2005	0.99	0
Mt. Hood WA	2003	0.74	0
	2004	0.88	0
	2005	0.76	0
Mt. Rainier NP	2003	2.09	1
	2004	1.91	0
	2005	2.39	0
Olympic NP	2003	5.78	10
	2004	4.68	6
	2005	4.58	3
Columbia River Gorge	2003	1.31	0
	2004	1.59	0
	2005	1.48	0

5.1.5.2 Class II Visibility

On a large spatial scale, visibility is typically evaluated as "regional haze" and is addressed as part of the Class I air quality related values (Chapter 5.1.4). On a local scale, "visibility" is usually evaluated by considering perceptibility of a plume from a stack or cooling tower.

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

However, Units 3 and 4 will require a ten-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. Cooling tower plumes are most visible when the ambient air is nearly saturated with water, when visibility is already poor.

5.1.5.3 Soils and Vegetation

Air quality permitting regulations require proponents of new major sources to provide an evaluation of potential impacts to air quality related values. These include impacts to visibility, soils and vegetation. In virtually all cases, the impact analysis for soils and vegetation has focused on impacts to Class I areas. The focus on Class I areas occurs because these areas often include sensitive environments, such as alpine lakes and streams, high-elevation vegetation, and sensitive habitat for threatened or endangered species. Section 5.1.4 addresses impacts to soils and vegetation in Class I areas. Such impacts were judged to be insignificant based on impact criteria established by Federal Land Managers.

For Class II areas, the concern for soil and vegetation impacts is different from Class I areas. Generally it is not a sensitive habitat that is of concern, but rather the economic well-being of the soils and vegetation for the area. Impacts to agriculture or forestry are the major concerns. There have been instances elsewhere in the U.S. where high levels of sulfur emissions from coal fired power plants, or smelters have caused localized impacts to vegetation and soils near the facility. In fact, the NAAQS were established to protect the public health and welfare, and secondary standards were identified specifically to protect ecological properties such as soils and vegetation. Units 3 and 4 air quality assessment indicates that NAAQS would be protected and the incremental increases in ambient pollutant concentrations would be very small. Because ambient concentrations attributable to the project would be so low, deposition of nitrogen and sulfur compounds would also be very low.

SECTION 5.2 WASTEWATER/STORM WATER DISCHARGE PERMIT APPLICATIONS (WAC 463-60-537)

The waste stream from the existing and additional facilities of the Grays Harbor Energy Center (see Section 2.8 - Wastewater Treatment, WAC 463-60-195) will be routed to a common pipe, and discharged to the existing blowdown line that was originally constructed for the nuclear plants. From the blowdown pipe, discharge to the Chehalis River will be through an existing diffuser, recorded as Outfall 001 in the existing NPDES permit. The discharge will be governed by the facility's National Pollutant Discharge Elimination System (NPDES) permit.