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

5.1.1 INTRODUCTION

Energy Northwest proposes to construct the Pacific Mountain Energy Center (PMEC), an Integrated Gasification Combined Cycle (IGCC) development, at the Port of Kalama, WA. The PMEC would gasify petcoke and/or coal to create synthesis gas or "syngas" to power two combined cycle combustion turbine electric power generating plants.

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 megawatt (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 Southwest Clean Air Agency (SWCAA) do not, strictly speaking, apply to the PMEC. However, SWCAA regulations are noted in the discussion of applicable regulations.

5.1.1.1 Summary of Changes since the September Submittal

A number of elements of the proposal that affect emissions to the atmosphere have been revised since the Application for Site Certification was submitted in September 2006. The following paragraphs describe those changes and summarize the implications for air emissions.

1) Duct firing

Energy Northwest has elected to include the option of employing duct burners in the HRSGs associated with the combustion turbines. The duct burners would add up to 80 MW of power generating capacity to the steam turbine generator, resulting in a total generating potential of 680 MW. The facility would be able to duct fire on syngas or natural gas. Duct firing capability will increase the maximum emissions from the HRSGs and cooling tower drift resulting from a higher water circulation rate. The previously identified maximum annual solid feed handling quantity, based on worst-case low Btu coal, will not be exceeded as a result of the duct firing addition.

2) Natural gas operation

Energy Northwest initially proposed that PMEC combustion turbines would fire natural gas for no more than 400 hours per year. Because installation of the equipment needed to generate electricity using natural gas as a combustion turbine fuel could occur much faster than

construction of the syngas gasifiers, Energy Northwest is now considering the possibility of operating on natural gas until the gasification process is operational. Even after the gasifiers come on line, there may be unforeseen circumstances that warrant extended operation on natural gas rather than syngas. Thus, while Energy Northwest still intends to operate primarily on syngas once the gasifiers are commissioned and operational, Energy Northwest proposes to eliminate any implied restrictions on natural gas operation. As discussed below, operation on natural gas results in lower emissions than operation on syngas.

3) Innovative Control Technology

Energy Northwest proposes lower NOx and SO2 emissions than have previously been deemed BACT for IGCC facilities. To allow for unanticipated issues during commissioning of Selexol (or equivalent) and SCR technologies at PMEC, Energy Northwest's initially proposed that these technologies be considered Innovative Control Technologies. In response to initial air quality regulatory agency comments, Energy Northwest has rescinded its proposed designation of Selexol (or equivalent) technology for sulfur removal from the syngas and Selective Catalytic Reduction (SCR) as Innovative Control Technologies. The proposed short-term sulfur concentrations in syngas have been reduced from 30 to 25 ppmv (3-hour average) and from 50 to 30 ppm (1-hour average). Energy Northwest has also revised the proposed NOx emission rate for combustion turbines firing natural gas from 5 to 3 ppm (24-hour average),

4) Other Emission Reductions

In addition to the commitment to lower NOx and SO2 emissions noted in paragraph 3, above, Energy Northwest is now proposing lower emission rates from several other emission units:

Emergency generator and firewater pump

The emission rates for the diesel-fueled emergency generator and the diesel-fueled firewater pump have been reduced to reflect the pending Tier II emission regulations that will be in place when PMEC becomes operational.

Mercury Control

Energy Northwest maintains that levels above 90% are not consistently demonstrated in practice, and discussions with Gasification Technology Suppliers and EPC contractors have indicated that equipment guarantees are at 90% control. PMEC is committed to minimizing mercury emissions and has proposed installing dual carbon beds and maintaining them appropriately. Energy Northwest would agree to a permit limit that requires a dual bed system be designed to achieve at least 95% overall removal but guaranteed to 90% removal. This would result in mercury emissions level of 29 lbs/yr per turbine (58 lbs total).

Cooling Tower Drift Rate

PMEC has halved the proposed droplet "drift" rate from the cooling towers, from 0.001% to 0.0005%. This also halves the quantity of particulate matter associated with cooling tower drift.

5) Air Quality Modeling Analyses

This revised air quality permit application is based on the same air quality dispersion models and meteorological data that were use in the September 2006 submittal. Model predictions are different, however, because of the changes in the project and the manner in which we evaluate various operating scenarios. In addition, emissions from a ship "hoteling" at the Port of Kalama's dock are included in this assessment. Because predicted concentrations of particulate matter and sulfur dioxide exceed prescribed significance thresholds, cumulative air quality assessments of these pollutants were conducted and are the results described in Section 5.1.3.

5.1.1.2 Organization

Section 5.1 constitutes a combined Notice of Construction (NOC) and PSD permit application. The requested PSD permit would address criteria pollutants emitted in significant quantities (defined in the federal PSD program). The NOC permit would address Toxic Air Pollutants (TAPs) and other criteria pollutants emitted in quantities below the PSD significant quantities.

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 regulations, summarizes anticipated emissions based upon the Best Available Control Technology (BACT) analyses, and identifies air pollutant emissions. A more detail presentation of BACT is included in the BACT analysis report (Appendix B-1 of this Application). Energy Northwest supplemented the BACT analysis with additional information in a letter sent to EFSEC November 30, 2006.
- Section 5.1.3 describes the local air quality impacts analysis used to estimate concentrations of criteria pollutants and TAPs in the vicinity of the project (i.e., Class II areas), presents concentrations calculated with dispersion models, and compares the calculations with regulatory criteria.
- Section 5.1.4 presents PMEC's impact on regional air quality related values, including visibility and acid deposition in national parks and wilderness areas (i.e. Class I areas), and additional impacts analysis related to growth.
- References are provided in Section 1.5, Sources of Information, of this Application.

5.1.1.3 Summary of Findings

The air quality impact assessment that follows indicates:

- Predicted maximum concentrations of most criteria pollutant emissions attributable to PMEC are less than the Significant Impact Levels (SILs) established by USEPA and Ecology. The exceptions are 1-hour, 3-hour, and 24-hour average SO_2, and 24-hour average PM_{10}, which were found to exceed the Class II SILs for some operating

scenarios. Subsequent cumulative impact analyses indicated that emissions of these pollutants would not cause or contribute to exceedance of any ambient standard or increment.

- Total air pollutant concentrations are less than the National, Washington, and Oregon Ambient Air Quality Standards (NAAQS, WAAQS, and OAAQS) established to protect human health and welfare when the maximum predicted concentrations are added to the existing background concentrations.
- Analyses of emissions attributable to PMEC and regional industrial sources for pollutants found to exceed the SILs predicted concentrations less than the Class II increments established by the PSD program.
- Predicted concentrations of all TAPs potentially released from the PMEC are either below Ecology's Small Quantity Emissions Rates (SQERs) or, as demonstrated by a modeling analysis, Ecology's Acceptable Source Impact Levels (ASILs).
- Sulfur dioxide (SO_2) and nitrogen oxides (NO_2) concentrations in Class I areas attributable to the PMEC are small fractions of United States Department of Agriculture Forest Service (USDA Forest Service) recommended levels for the protection of sensitive vegetation.
- Depositions of secondary aerosols from the facility are less than USDA Forest Service criteria for significant impacts to soils in these areas. Based on USDA Forest Service criteria, acidification of aquatic resources is not expected.
- Secondary aerosols potentially formed by emissions from the PMEC would not affect regional visibility in Class I areas even on the clearest days.

5.1.2 EMISSIONS

In order to determine the potential air quality impacts associated with a proposed industrial facility such as PMEC and the regulations that apply to PMEC, one must determine the types and quantities of air pollutants that will be emitted. To determine the pollutant emissions, one must identify the physical and operational characteristics of the facility. Part 2 of the Application for Site Certification provides a detailed physical description of the PMEC. 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 the spreadsheets of Appendix B-3.

5.1.2.1 Normal Operation and Short-term Emission Rates

5.1.2.1.1 Power Generation Units

The PMEC would gasify coal or petcoke to power two combustion turbine electric power generating plants. The electric power generating plants would have three sources of power generation, two combustion turbine-generators (CTGs) with heat recovery steam generators (HRSGs) and a steam turbine-generator (STG). The total net output of the facility would be approximately 680 MW.

The combustion turbines would be designed to accept preheated syngas as the primary fuel, with natural gas as an alternative fuel. Preheated syngas from the gasifiers and compressed air are supplied to the turbine combustors. Diluent nitrogen added to the syngas fuel reduces the flame temperature in the combustor and thereby reduces production of NO_x. 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 STG. Steam generation in the HRSG may be supported by using duct burners, resulting in up to 40 MW per HRSG of additional power generation. 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 NO_x emissions is located within the HRSG.

Although a combustion turbine manufacturer has not been selected, emissions estimates are conservatively based on Siemens model SGT6-5000F combustion turbines because they tend to have higher emissions than alternative models. The combustion turbines would be optimized to operate primarily on syngas, although they would also be able to operate on natural gas.

The combustion turbines are the primary source of air pollutant emissions from the PMEC. The combustion turbines are expected to meet the proposed continuous operation emission limits for each criteria pollutant (e.g., 3 ppmvd NOx) between 70 percent load and 100 percent load. Turbine operation may be supplemented by combustion with duct burners in the HRSG. Both the combustion turbines and the duct burners will be capable of operating on syngas or natural gas. Including startup, there are eight potential operation modes:

1) 100% combustion turbine load firing syngas with duct burners firing syngas
2) 100% combustion turbine load firing syngas with duct burners firing natural gas
3) 100% combustion turbine load firing natural gas with duct burners firing natural gas
4) 100% combustion turbine load firing syngas
5) 100% combustion turbine load firing natural gas
6) 70% combustion turbine load firing syngas
7) 70% combustion turbine load firing natural gas
8) Combustion turbine startup/shutdown firing natural gas

Table 5.1-1 presents short-term (1-hour to 24-hour) average emission rates for various combustion turbine operating modes. Although operation with duct burners produces the highest overall facility emissions, the modeling analyses considered all eight 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

SHORT-TERM POWER GENERATION EMISSION RATES

Pounds per hour per Combustion Turbine/HRSG

Operating Mode	NOx	CO	1hr SO_2	3hr SO_2	24hr SO_2	PM_{10}	VOC	NH3
CTsyn-DBsyn	33.7	126.1	51.6	43.0	25.8	27.5	16.3	20.8
CTsyn-DBng	33.9	134.4	47.3	39.9	25.1	27.6	16.6	20.9
CTng-DBng	28.0	114.5	21.6	21.6	21.6	23.6	15.9	17.3
CTsyn	30.0	98.0	44.3	36.9	22.1	24.0	9.0	18.5
CTng	24.1	78.0	18.6	18.6	18.6	20.0	9.0	14.9
CTsyn70	24.0	72.0	34.8	29.0	17.4	23.0	9.0	14.9
CTng70	19.2	57.0	14.2	14.2	14.2	16.0	9.0	14.9
Maximum	33.9	134.4	51.6	43.0	25.8	27.6	16.6	20.9

Key: CT =combustion turbine, syn = syngas, DB = duct burner, ng = natural gas. (e.g., CTsyn-DBng = a combustion turbine firing syngas with HRSG duct burners firing natural gas.
Note: SO2 emissions vary with averaging time because the syngas sulfur concentrations changes with averaging time

Except for ships, which are discussed further below, other emission units operate at a constant rate during normal operation. A description of each emission unit's normal operation follows.

5.1.2.1.2 Tank Vent Oxidizer

The tank vent oxidizer combusts natural gas or syngas in a burner to oxidize off-gases (such as air or nitrogen vent streams with trace amounts of hydrogen sulfide) from various tank and process vents associated with the gasification process. Because mass emission rates (lb/hr) associated with the burner are higher when firing syngas, short-term emission rates used in the modeling analyses are based on syngas combustion. In addition to pollutants generated by syngas combustion, the oxidation of reduced sulfur compounds results in additional SO_2 emissions (estimated at 3.5 pounds per hour by the design team). Because emissions from the tank vent oxidizer during gasifier startup are lower than the short-term emissions with normal syngas operation, the tank vent oxidizer normal emissions are used in all modeling scenarios. Table 5.1-2 shows tank vent oxidizer emission rates.

TABLE 5.1-2

TANK VENT OXIDIZER EMISSION RATES

		NOx	CO	SO2	PM10	VOC	Firing rate (MMBtu/hr)
Syngas firing							
Emission factor	lb/MMBtu	0.3	0.09	0.021	0.01	0.004	65
Normal Operation	lb/hr	19.5	5.85	1.37	0.65	0.26	
Startup	lb/hr	3	0.9	0.21	0.1	0.04	10
Natural gas firing							
Emission factor	lb/MMBtu	0.3	0.09	0.0083	0.01	0.004	40
Normal Operation	lb/hr	12	3.6	0.33	0.4	0.16	
Startup	lb/hr	9	2.7	0.25	0.3	0.12	30
Additional SO2 from tank vent gas (lb/hr)				3.5			
Max 1-hr emissions	lb/hr	19.5	5.85	4.87	0.65	0.26	
Max 3-hr emissions	lb/hr	19.5	5.85	4.19	0.65	0.26	
Max 24-hr emissions	lb/hr	19.5	5.85	3.91	0.65	0.26	
Annual emissions	lb/hr	4.5	1.35	3.77	0.15	0.06	15
Annual emissions	ton/yr	19.71	5.91	16.53	0.66	0.26	

5.1.2.1.3 Auxiliary Boiler

The auxiliary boiler will only combust natural gas and is mainly used to generate steam to assist in the startup of the combustion turbines and gasification process. The steam reduces the duration of the startup period for the combustion turbine generator and steam turbine generator. Although the boiler is unlikely to operate when a combustion turbine is operating, the modeling includes boiler emissions for a 24 hour period. Emissions are based on the use of low-NOx burners and good combustion control (Table 5.1-3).

TABLE 5.1-3
AUXILIARY BOILER EMISSION RATES

	NOx	CO	SO2	PM10	VOC
lb/MMBtu	0.036	0.074	0.008	0.005	0.004
lb/hr	4.68	9.62	1.07	0.65	0.52
ton/yr	5.12	10.53	0.50	0.71	0.57
Annual emissions based on 25% capacity factor					

5.1.2.1.4 Flare

The gasification island elevated flare's primary function is to combust syngas from the gasifiers during startup until the syngas is generated at sufficient quality and quantity to fuel a combustion turbine. The flare may be used to combust on-spec syngas for a short period of time if one or both of the combustion turbine(s) are suddenly forced to shut down. Syngas sent to the flare during normal flaring events would first pass through particulate matter filters, acid gas wet scrubbers, the Selexol (or equivalent) sulfur recovery process, and activated carbon for mercury removal. Flaring of untreated syngas or other streams within the plant would only occur as an emergency safety measure during unplanned plant upsets or equipment failures. The flame would be enclosed in a refractory-lined combustion chamber, effectively eliminating any visible flame.

During normal operation of the facility, emissions from the flare are attributable solely to a 2 MMBtu/hr natural gas-fired pilot light. Thus, the normal operations scenario considers only emissions from the pilot light and a separate table of flare emissions is not provided. Emissions associated with startup and upset scenarios are discussed and tabulated separately below.

5.1.2.1.5 Emergency Diesel Engines

A diesel-fueled engine powering an emergency generator will be on-site to power essential systems in the event power from the grid is not available. In addition, a diesel-fueled engine powering a firewater pump will be available to provide pressurized water supply for fire protection. Both engines will meet the low emission limits prescribed by EPA's pending Tier II emission regulations. Ordinarily, these engines will operate only a few hours per month for testing. In the modeling analysis, it is assumed that both engines are being tested in the one hour scenario, but each operates only hour in the 3-hour, 8-hour, and 24-operating scenarios (Table 5.1-4).

TABLE 5.1-4
EMERGENCY ENGINE EMISSION RATES

	NOx	CO	SO2	PM10	VOC
Emergency generator					
lb/hp-hr	0.011	0.006	0.000	0.000	0.011
lb/hr	28.16	15.45	1.08	0.88	28.16
tpy	1.41	0.77	0.05	0.04	1.41
Emergency fire water pump					
lb/hp-hr	0.017	0.006	0.000	0.001	0.017
lb/hr	5.15	1.72	0.12	0.26	5.16
tpy	0.26	0.09	0.01	0.01	0.26
Annual emissions based on 100 hours of operation.					

5.1.2.1.6 Cooling Towers

Three cooling towers would be installed and operated to condense steam so that the water can be recycled. These cooling towers release water droplets that contain dissolved solids that occur naturally in the water supply, but are concentrated in the cooling process.

The Power Block cooling towers are configured with in two sets of six cells. The Gasification/ASU cooling towers is configured as a single set of seven cells. The quantity of water released as droplets to the air (the drift rate) is based on 0.0005% of the tower 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 for the makeup water. Short-term emissions from the cooling tower are based on the assumption that water throughput (gallons per minute) is maximized in all cooling tower cells (Table 5.1-5).

TABLE 5.1-5
COOLING TOWER EMISSION RATES

	Power Block	Gasification/ASU
Heat rejected, million Btu/hr	1,740	1,015
Water circulation rate, million lb/hr	146.9	85.7
Maximum dissolved solids, ppmw	2,400	2,400
Drift, fraction of circulating water	0.0	0.0
PM10 emission rate, lb/hr	1.8	1.0
PM10 emission rate, ton/yr	7.7	4.5

Note: Maximum dissolved solids based on total dissolved solids in municipal water supply and 12 concentration cycles.

5.1.2.1.7 Solid Fuel Handling

Unit trains delivering feedstock materials would unload in a negatively pressurized building into an underground hopper.[1] A baghouse would clean particulate matter from the air in the unloading building. The petcoke or coal may also be unloaded from ships or barges using a rail mounted, continuous bucket ship unloader, then moved onto a dockside conveyor that is partially open on the top. This dockside conveyor would also be equipped with an associated baghouse to control the fugitive dust emissions.

[1] Note that no fugitive dust is expected from the tops of the railcars because the unit trains would be unloading at low speed and because the trains would have traveled up to 60 miles per hour (mph) for hundreds of miles prior to arrival at the PMEC. Any dust associated with coal or petcoke when the railcars were loaded would have been blown off long before arriving at PMEC.

The petcoke and/or coal would move from the train or ship unloading areas on a covered conveyor to a transfer point between two enclosed fuel storage domes. These domes would ensure maximum control of fugitive dust and an enhanced visual appearance. The transfer point between the domes would have a baghouse to control fugitive dust emissions. The petcoke/coal would then be loaded into the storage domes. Only after the dust has settled inside the domes during each batch transfer would the dome ventilation system be restarted. Thus, the only sources of fugitive dust emissions would be the unloading of ships and trains, the conveyors transfer point between the storage domes, and the ventilation of the storage domes, all of which would be controlled by high efficiency fabric filter baghouses.

Fugitive particulate matter emissions were estimated using appropriate USEPA AP-42 emission factors for Aggregate Handling (Section 13.2.4). Short-term emissions were calculated for all sources, although all sources would not occur simultaneously; accordingly, three separate operating scenarios were considered to encompass the range of possible emissions for different combinations of source activities. The short-term modeling analyses assume that both a train and a ship are unloaded at the same time, for at least 24 consecutive hours. As indicated in the short term emissions summary (Section 5.1.2.1.10) below, calculated particulate matter emissions from the unloading activities are less than half a pound per hour.

5.1.2.1.8 Ships

One of the advantages of the Port of Kalama site is access to the Columbia River, which allows solid feedstock to be delivered by ships or barges. Energy Northwest does not plan to own or operate ships or barges carrying coal or petroleum coke, nor will it own the dock at which the feedstock is unloaded (it is owned by the Port of Kalama). However, the modeling analysis conservatively includes hoteling emissions from a Panamax sized bulk carrier, the type of ship expected to serve PMEC (Table 5.1-6). Based on the anticipated 60,000-70,000 tons of feedstock per ship and a 1,900-2,500 ton per hour unloading rate, it will take approximately 28-37 hours to unload a ship. Thus, short-term modeling analyses include a ship present for the 1, 3, 8, and 24-hour time periods.

TABLE 5.1-6
HOTELING SHIP EMISSION RATES

	NOx	CO	SO_2	PM_{10}	VOC
grams/kw-hr	13.90	1.10	6.16	0.71	0.40
lb/hr	12.0	0.9	5.3	0.6	0.3
tpy	7.5	0.6	3.3	0.4	0.2

Emissions from 1776 KW auxiliary generator operating at 22% load.
Annual emissions based on 34 ships and 37 hours per visit.

5.1.2.1.9 Fugitive Emissions

VOC emissions associated with normal leakage from valve seals, pump and compressor seals, pressure relief valves, flanges, and similar equipment were calculated using anticipated component counts and fugitive emission factors from *Protocol for Equipment Leak Estimates,* (USEPA 453-R95-017, November 1995). Fugitive VOC emissions associated with leaks from gaseous and liquid streams are estimated to be 0.6 pounds per hour and 2.6 tons per year.

5.1.2.1.10 Short-Term Emissions Summary

Short-term emission rates for normal operation are summarized in Table 5.1-7. This table presents the maximum normal operating rate for the combustion turbines (full load with duct burners), and conservatively includes the auxiliary boiler and emergency generator and fire water pump.

5.1.2.2 Annual Operation and Emissions

Emissions are typically lower on an annual average basis than on a short-term basis because equipment does not typically operate at maximum capacity for all hours and because equipment does not typically operate every hour of the year. Another consideration is the net effect of a shutdown followed by a period of potentially higher emissions during startup. This section identifies how annual emissions were calculated for PMEC emission units. Table 5.1-8 summarizes facility-wide annual emissions; additional detail on emission calculations is provided in Appendix B-3.

Annual emissions from the combustion turbines consider startups and maximum normal operations (with duct firing) for the remaining hours of the year. For some pollutants (SO2, and PM10), startup emissions are lower than normal operation, so it was assumed that the combustion turbines operated 8,760 hours per year at 100 percent load with duct firing. In all cases, the higher of natural gas and syngas mass emission rates (lb/hr) were evaluated in the annual operating scenario.

Energy Northwest anticipates there will be fewer than 100 CTG-startup hours per year (50 hours per CTG) once PMEC is fully commissioned. Most CTG startups (light off to emission compliance) are expected to take about two hours, but some startups could take up to six hours per CTG. During the first two or three years, it is likely that there will be more startups and the average startup time may take longer. For the sake of the dispersion modeling, emissions are based on 200 hours of startup per combustion turbine per year. Short-term emissions from startup operations are discussed in Section 5.1.2.3.

Annual emissions from the tank vent oxidizer are based on syngas combustion 8,760 hours per year. Because the annual average firing rate is only 15 MMBtu/hr (compared with 65 MMBtu/hr on a short-term basis), the annual emissions cannot be scaled directly from hourly emission rates. Because startup emissions from the tank vent oxidizer are lower than the short-term emissions with syngas operation, startup emissions are ignored in the annual emission calculations.

TABLE 5.1-7
FACILITY-WIDE SHORT-TERM EMISSION RATES

lb/hr

Operating Mode	24hr NOx	1hr CO	8hr CO	1hr SO2	3hr SO2	24hr SO2	24hr PM10	VOC	24hr NH3
Combustion Turbine 1	33.9	134.4	134.4	51.6	43.0	25.8	27.6	16.6	20.9
Combustion Turbine 2	33.9	134.4	134.4	51.6	43.0	25.8	27.6	16.6	20.9
Tank Vent Oxidizer	19.5	5.85	5.85	4.9	4.2	3.9	0.7	0.26	
Auxiliary Boiler	4.68	9.62	9.62	1.1	1.1	1.1	0.7	0.52	
Flare	0.14	1.1	1.1	0.01	0.01	0.01	0.02	0.012	
Emergency Diesel Generator	1.2	15.4	1.9	1.08	0.36	0.05	0.04	28.2	
Emergency Diesel Fire Pump	0.2	1.7	0.2	0.1	0.0	0.0	0.01	5.16	
Power Block Cooling Towers							1.8		
Gasification/ASU Cooling Towers							1.0		
Transfer point to storage dome							0.1		
Storage dome ventilation							0.1		
Ship unloading							0.4		
Train unloading							0.1		
Ship hoteling	12.0	0.9	0.9	5.3	5.3	5.3	0.6	0.3	
Total	106	303	288	116	97	62	61	68	42

TABLE 5.1-8
FACILITY-WIDE ANNUAL EMISSION RATES

tons per year

Emission Unit	NOx	CO	SO2	PM10	VOC	NH3
Combustion Turbine 1	157	849	75	121	97	91
Combustion Turbine 2	157	849	75	121	97	91
Tank Vent Oxidizer	20	6	17	1	0.3	0
Auxiliary Boiler	5	11	0	1	1	0
Flare	14	301	4	2	1	0
Emergency Diesel Generator	1	1	0.1	0.04	1	0
Emergency Diesel Fire Pump	0.3	0.1	0.0	0.01	0.3	0
Power Block Cooling Towers	0	0	0	8	0	0
Gasification/ASU Cooling Towers	0	0	0	5	0	0
Transfer point to storage dome	0	0	0	0.03	0	0
Storage dome ventilation	0	0	0	0.03	0	0
Ship unloading	0	0	0	0.2	0	0
Train unloading	0	0	0	0.03	0	0
Ship hoteling	8	1	3	0.4	0	0
Fugitive VOCs	0	0	0	0	2.6	0
Total	363	2,017	175	258	198	183

The auxiliary boiler would operate mainly during startups of the combustion turbines and gasification process. To estimate annual emissions, we conservatively assumed the boiler would have an annual capacity factor of 25% (i.e., emissions would not exceed 25% of the emissions resulting from operating at maximum load every hour of the year).

The flare is available to combust off-spec gas during a gasifier startup or to combust on-spec gas when a combustion turbine must be suddenly taken off line. In addition to 8,760 hours of pilot light operation, the annual emissions from the flare consider gasifier startup and shutdown operation, (i.e., syngas routed to the flare instead of the combustion turbine). After the initial three years of plant operation, Energy Northwest expects the annual gasifier startup/shutdown time to be fewer than 930 hours per year total for the three gasifiers. During the first three years of facility operation, however, it is anticipated that up to 50 percent more gasifier startup time (about 1400 hours per year, total for the three gasifiers) may be required while the startup process is optimized through facility-specific experience. Therefore, annual emissions consider 1,400 hours of startup/shutdown operation at 280 MMBtu/hr to account for the worst-case emissions during these initial years.

Although Energy Northwest intends to test the diesel fueled emergency generator and firewater pump only a few hours per month, the annual emission scenario assumes they are operated 100 hours per year at their maximum capacity rating.

Annual PM10 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/gasifier production rates decrease. Consequently, this assumption provides a conservative estimate of cooling tower emissions.

Annual dust emissions from feedstock (petroleum coke and coal) handling are based on an anticipated demand of 2,389,500 tons of coal. In practice, dust emissions would probably be lower if petroleum coke is used because it has a higher energy value and less material must be brought to the site. The modeling analysis assumes that this quantity of feedstock is imported both by train and by ship, so dust emissions are conservatively estimated on an annual basis

5.1.2.3 Startup

Emissions of some pollutants are sometimes higher during startup than during normal operations because combustion is not yet optimized 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 70 percent load or greater). Combustion turbine NOx emissions are also higher during startup, in part because the SCR is not effective at low exhaust gas temperatures.

Energy Northwest anticipates that individual gasifier train startups may occur as often as 12 times per year. One or both of the other two gasifier trains and one or both of the two combustion turbines may also be operating during a gasifier startup event. The startup typically occurs over a two to five day period, with most of the time devoted to a very gradual heating of the gasifiers using natural gas (or product syngas, if available) at low firing rates.

The gasifiers themselves do not have any direct emissions during normal operation or startup. Natural gas or syngas (if one of the other gasifiers is already operating) fired burners internal to the gasifier vessel would gradually increase from 15 to 255 MMBtu/hr to heat the gasifier. Through most of the gasifier startup period, emissions from the gasifier are minor because of the low firing rates. During this warm-up process, the products of partial (sub-stoichiometric) combustion from the gasifier will be routed to the flare for more complete oxidation.

Energy Northwest anticipates that it will take from 44 to 60 hours for a gasifier to warm to a temperature sufficiently high to introduce solid slurry feed. Another approximately four to eight hours will be required after the introduction of solid feed for the quality and quantity of syngas to become adequate to support operation of a combustion turbine. When the warmed gasifier is switched to slurry feed, the initial syngas product is routed through the syngas treatment system, where it is filtered to remove particulate matter, water-scrubbed to remove chlorides and certain trace metals, treated with Selexol (or equivalent) to remove sulfur, passed through carbon adsorption units to remove mercury, and then sent to the flare. When the quality and quantity of syngas is sufficient and it is at the proper operating condition, treated syngas would be diverted from the flare to the combustion turbine.

Gasifier shutdown consists of decreasing the feed rate to gasifier, switching the combustion turbines to natural gas fuel, and diverting the product syngas to the flare for short time (30 to 60 minutes) before stopping the solid feed entirely. After cutting solid feed, the gasifier is gradually

cooled by firing relatively small quantities of natural gas or product syngas (100 MMBtu/hr or less) for about four to eight hours. During this time, the partially oxidized products of combustion are routed to the flare for disposal.

As the refractory is being warmed during gasifier startup, natural gas or syngas burners in the tank vent oxidizer are fired so that it is ready to oxidize tank vent off gases as the gasifier commences operation. The tank vent oxidizer the firing rate (and emissions) during this period are lower than during normal operation.

Although the flare is designed to accept up to 110 percent of the maximum syngas to be directed to both combustion turbines, Energy Northwest does not plan to start two gasifiers at the same time. The startup scenario considered in the dispersion modeling is based on flaring 1,750 MMBtu of syngas for 9 consecutive hours (8 hours prior to diverting syngas to the combustion turbines and an hour of transition time). Given that 1,750 MMBtu is sufficient to operate the combustion turbine, this is not an economically desirable operating mode and it is in the operator's interest to minimize flaring of valuable syngas fuel; after a few years of experience, the flaring is expected to be reduced significantly.

The combustion turbines will start using natural gas, and are therefore independent of the gasifier operating mode. Unless steam is available from another source (such as the HRSG associated with the other combustion turbine), the auxiliary boiler will be used to generate steam for pre-startup cleaning activities and to heat the HRSG and steam turbine. The combustion turbines are expected to normally reach at least 70 percent load within two hours. At this operating rate, the SCR will be operational and the combustion turbine emission rates will meet the proposed emission limits. Thus, a combustion turbine is operating normally within eight hours of the boiler startup, and two hours later the second combustion turbine may be in normal operation. For the sake of our short-term modeling, however, we have examined a scenario in which it takes six hours to start the combustion turbine.

Table 5.1-9 summarizes emissions averaged over the typical (2-hour) combustion turbine startup period. Although NOx, CO, and VOC emissions during startup are much higher than during the normal operations, SO2 and PM10 emissions are lower during startup.

Normally, the higher emissions associated with a startup would be either 1) the combustion turbines starting up on natural gas or 2) the combustion turbines operating normally on full load while a substantial quantity of syngas is flared in the final stages of a gasifier coming on line. The worst-case short term scenario is when both combustion turbines are started during a period that overlaps the 4-9 hours of substantial syngas flaring during a gasifier startup. Emissions associated with that worst-case scenario are identified in Table 5.1-10. Note that emissions from most PMEC sources are no higher than normal operation (indicated by gray shading in Table 5.1-10).

TABLE 5.1-9
COMBUSTION TURBINE STARTUP EMISSION RATES

Average Startup/shutdown Emission, lb/hr					Maximum Normal Operation
	Hot Start	Warm Start	Cold Start	Maximum	
NOx	108	116	121	121	34
CO	2116	2740	2205	2740	134
SO2	19	19	19	19	52
PM10	10	11	11	11	28
VOC	204	263	212	263	17
Typical duration	52 min	81 min	101 min	(N/A)	(N/A)

5.1.2.4 Upset Conditions

Every industrial facility faces the possibility of an "upset" condition. While it is impossible to know that issues will arise, the most likely upsets at the PMEC facility are 1) a transformer problem or disruption of the transmission lines that carry electricity from the site, or 2) a problem with the gasifier technology. Upsets of these types were evaluated with dispersion modeling to confirm that ambient concentrations would not exceed ambient air quality standards established to protect human health and welfare. The scenarios are described below, and emissions estimates corresponding to these scenarios are provided in Tables 5.1-11 and 5.1-12.

Although the most common function of the flare is to safely combust off-spec syngas as the gasifiers are started up, the flare is also designed to serve as a safety device. At PMEC, the flare is designed to combust 110 percent of the syngas feed to both combustion turbines if necessary. In the event of a transmission line or transformer failure, for example, the combustion turbine generators would suddenly "trip" and force the combustion turbines into a rapid shutdown. In that event, the syngas being produced by the gasifiers would be diverted to the flare. This is simply the reverse of the startup scenario, except that the quantity of syngas may be more than twice as much as during a normal startup. The design team indicates the gasifier output will be reduced to the quantity of gas used at 70 percent combustion turbine load within one hour.

The model evaluation of a transmission line failure was based on both combustion turbines operating at maximum load on syngas (with duct burners), with a trip forcing the entire syngas feed from both combustion turbines to the flare. It was assumed that the combustion turbines operated for one hour at an average 70 percent load, and then shut down. It was further assumed that syngas production averaged 85 percent for the first hour, 80 percent of the syngas feed for both combustion turbines for the 3-hour and 8-hour average periods, and 80 percent of one combustion turbine feed rate for the 24 hour average period. The modeling assumes all other emissions units continue to operate normally. Table 5.1-11 summarizes facility-wide emissions during this hypothetical upset scenario, with shading to indicate emission units that would continue to operate normally.

TABLE 5.1-10
STARTUP EMISSION RATES

Source	24hr NOx	1hr CO	8hr CO	1hr SO2	3hr SO2	24hr SO2	24hr PM10
Combustion Turbine Generator 1	55.7	2,740	2,089	51.6	43.0	25.8	27.6
Combustion Turbine Generator 2	55.7	2,740	2,089	51.6	43.0	25.8	27.6
Tank Vent Oxidizer	19.5	5.9	5.9	4.9	4.2	3.9	0.7
Auxiliary Boiler	4.7	9.6	9.6	1.1	0.5	0.3	0.7
Flare	58.47	2,696	2,696	36.90	30.76	18.46	6.68
Power Block Cooling Towers (drift)	0	0	0	0	0	0	1.8
Gasification/ASU Cooling Towers (drift)	0	0	0	0	0	0	1.0
Transfer point to storage dome	0	0	0	0	0	0	0.085
Storage dome ventilation	0	0	0	0	0	0	0.085
Ship unloading	0	0	0	0	0	0	0.350
Train unloading	0	0	0	0	0	0	0.085
Ship hoteling	12.0	0.9	0.9	5.3	5.3	5.3	0.612
Total	206	8,193	6,890	151	127	80	67
Gray signifies normal operating emissions							

TABLE 5.1-11
EMISSIONS FOR TRANSMISSION LINE FAILURE UPSET SCENARIO

lb/hr

Source	24hr NOx	1hr CO	8hr CO	1hr SO2	3hr SO2	24hr SO2	24hr PM10
Combustion Turbine Generator 1	0.8	57.0	7.1	14.2	4.7	0.6	0.7
Combustion Turbine Generator 2	0.8	57.0	7.1	14.2	4.7	0.6	0.7
Tank Vent Oxidizer	19.5	5.9	5.9	4.9	4.2	3.9	0.7
Flare	122.5	5,744	5,405	78.6	61.7	18.4	14.0
Power Block Cooling Towers (drift)	0.0	0.0	0.0	0.0	0.0	0.0	1.8
Gasification/ASU Cooling Towers (drift)	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Transfer point to storage dome	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Storage dome ventilation	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Ship unloading	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Train unloading	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Ship hoteling	12.0	0.9	0.9	5.3	5.3	5.3	0.6
Total	156	5,865	5,426	117	81	29	20
Gray signifies normal operating emissions							

TABLE 5.1-12
EMISSIONS FOR GASIFIER UPSET SCENARIO

lb/hr

Emission Unit	**24hr NOx**	**1hr CO**	**8hr CO**	**1hr SO2**	**3hr SO2**	**24hr SO2**	**24hr PM10**
Combustion Turbine 1	33.7	126.1	126.1	51.6	43.0	25.8	27.5
Combustion Turbine 2	28.0	114.5	114.5	21.6	21.6	21.6	23.6
Tank Vent Oxidizer	19.5	5.85	5.85	4.9	4.2	3.9	0.65
Flare	123	2,872	2,703	524	370	61	14.0
Power Block Cooling Towers	0	0	0	0	0	0	1.8
Gasification/ASU Cooling Towers	0	0	0	0	0	0	1.03
Transfer point to storage dome	0	0	0	0	0	0	0.09
Storage dome ventilation	0	0	0	0	0	0	0.09
Ship unloading	0	0	0	0	0	0	0.35
Train unloading	0	0	0	0	0	0	0.09
Ship hoteling	12.0	0.9	0.9	5.3	5.3	5.3	0.61
Total	216	3,119	2,950	608	444	118	70

During a flaring event, CO emissions would be much higher than normal because the combustion would not be as carefully controlled as in a combustion turbine and NOx emissions would be higher because the flare is not equipped with Selective Catalytic Reduction. However, the flaring event would be short-lived, and the greater plume rise would partially offset higher impacts that might result from higher emissions.

It is also possible that some form of failure at the gasifier would direct syngas to the flare. The degree of failure is variable and, again, impossible to predict, but is most likely to be a relief valve or compressor malfunction. The modeling evaluation of a possible gasifier upset assumes both combustion turbines are operating at maximum load on syngas (with duct firing); with a gasifier problem, one combustion turbine is diverted to natural gas while the other remains on syngas. The scenario assumes the syngas from the problem gasifiers is redirected from the combustion turbine to the flare, at 85% of one combustion turbine syngas demand for the first hourand 80% of the fuel demand for the three, eight, and 24-hour average periods. Furthermore, we allow for the possibility of a problem with the Selexol (or equivalent) system by assuming averaging syngas sulfur concentrations range from 400 ppmw in the first hour to 50 ppmw over the 24-hour average. Table 5.1-12 summarizes facility-wide emissions during this hypothetical upset scenario, with shading to indicate emission units that would continue to operate normally.

Predicted concentrations resulting from these two scenarios are presented in Section 5.1.3. This remainder of Section 5.1.2 discusses federal, state, and local air quality regulations and guidelines that apply to the PMEC. It also identifies anticipated emission rates for criteria and TAPs associated with the combustion of syngas and natural gas. PMEC emissions are identified for short-term operating scenarios and a worst-case (from an emissions perspective) annual operating scenario. Additional detail regarding the selection of emission rates is available in the BACT analysis, which is included as Appendix B-1 of the Application.

5.1.2.5 Emission Standards

5.1.2.5.1 New Source Performance Standards

USEPA has established performance standards for a number of air pollution sources in 40 Code of Federal Regulation (CFR) Part 60. These New Source Performance Standards (NSPS) represent a minimum level of control that is required on a new source. This section identifies those NSPS that apply to PMEC emission units, including 40 CFR 60, Subparts Da, Db, Dc, KKKK, Y and A. After adoption as described below, the PMEC would also need to comply with 40 CFR 60, Subpart HHHH.

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 PMEC meet these criteria, and will be Subpart KKKK when burning natural gas or syngas derived from petcoke. Subpart KKKK will

limit NOx emissions to 42 ppm on syngas and 15 ppm on natural gas, and limit SO2 emissions to 0.90 lb/MWhr. Proposed emissions are well below these limits.

Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

Subpart Da applies to new electric utility steam generating units with heat input from fossil fuels exceeding 250 MMBtu/hr. Heat recovery steam generators and associated stationary combustion turbines burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to Subpart Da and are not subject to Subpart KKKK. Turbines associated with PMEC would be considered "electric utility stationary gas turbines" because more than one-third of their potential electric output capacity would be supplied to a utility power distribution system. Subpart Da (instead of Subpart KKKK) would apply to PMEC combustion turbines in 12-month periods when at least 75 percent of their heat input is syngas derived from coal. If the duct burners fire more than 75 percent coal-derived syngas over a 12 month period and the combustion turbines do not, Subpart Da applies only to the duct burner emissions and Subpart KKKK applies to the combustion turbine emissions. Thus, NSPS applicability may swing between Subpart Da and Subpart KKKK from month to month depending upon fossil fuel selection.

In practice, the emission limits imposed by NSPS are rarely important for new sources because the emission limits deemed Best Available Control Technology (BACT) are virtually always lower.

Subpart HHHH, Hg Budget Trading Program General Provisions

Subpart HHHH applies to stationary coal-fired boilers or combustion turbine generators. Included in the definition of "coal-fired" is coal-derived fuel (such as syngas). Because the combustion turbines at PMEC fit these criteria, Energy Northwest must comply with the mercury budget and trading provisions in Subpart HHHH. After adoption by Ecology and approved by USEPA, PMEC would have to comply with emission limits and requirements resulting from the state rule that would replace federal requirements.

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

Subpart Db applies to steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and have a heat input capacity from fuels combusted in the steam generating unit of greater than 100 MMBtu/hr. Subpart Db would apply to the auxiliary boiler because it is rated at 130 MMBtu/hr.

Because the auxiliary boiler is fired solely with natural gas, the only substantive emission limits apply to NO_x (0.10 lb NO_x per MMBtu heat input) and SO_2 (0.02 lb SO_2 per MMBtu heat input). These limits apply at all times including startup, shutdown, and malfunction, and are expressed as a 30-day rolling average. The emission rates proposed for the auxiliary boiler comply with those prescribed by Subpart Db.

Subpart Db requires operators to install, calibrate, maintain, and operate a Continuous Emission Monitoring System (CEMS) unless they choose a parametric monitoring option. PMEC plans to install a CEMS.

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 greater than 10 MMBtu/hr and less than 100 MMBtu/hr. Subpart Dc would apply to the tank vent boiler because it is rated at 65 MMBtu/hr.

Because the tank vent boiler is fired with syngas and natural gas, a PM_{10} emission limit (0.03 lb PM_{10} per MMBtu heat input) applies. SO_2 emissions are limited to 0.20 lb SO_2 per MMBtu heat input. Subpart Dc allows facilities to limit SO_2 emissions to 1.2 lb SO_2 per MMBtu heat input and comply with a 90 percent reduction of SO_2 from the potential emission rate instead of limiting SO_2 emissions to 0.20 lb SO_2 per MMBtu heat input. Subpart Dc also requires a limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. The SO_2 limits apply at all times, but the PM_{10} limits do not apply during startup, shutdown, and malfunction.

Subpart Dc requires operators to install, calibrate, maintain, and operate a CEMS for SO_2 and either oxygen or carbon dioxide at both the inlet and outlet of the SO_2 control device. An alternative to the CEMS for SO_2 is estimating the SO_2 emission rates by sampling the fuel using approved Method 6B. A Continuous Opacity Monitoring System (COMS) is also required. The emission rates proposed for PMEC comply with those prescribed by Subpart Dc.

Subpart Y, Standards of Performance for Coal Preparation

Subpart Y applies to coal processing and conveying equipment, storage systems, and transfer and loading systems with capacities exceeding 200 tons per day. The only substantive emission standard is an opacity limit of 20 percent.

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, PMEC 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. PMEC 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.

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

The PMEC has the potential to emit non-criteria air pollutants that are regulated federally by the CAA Section 112 and locally 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.

Prior to the Clean Air Act Amendments in 1990, National Emission Standards for Hazardous Air Pollutants (NESHAPS) were risk-based emission standards for eight hazardous air pollutants (HAPs). Under the provisions of Title III of the 1990 Clean Air Act Amendments, EPA was required to regulate the emissions of a total of 189 HAPs from all stationary and mobile sources.2 EPA does this by specific industry categories so that it can tailor the controls to the major sources of emissions and the HAPs of concern from that industry. The rules promulgated under Title III generally specify the Maximum Achievable Control Technology (MACT) that must be applied for a given industry category. Consequently, these rules are often called MACT standards (the terms "NESHAPS" and "MACT standards" are used interchangeably).

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

Sources are subject to MACT rules only if they have a potential to emit more than 10 tons per year of a single HAP or more than 25 tons per year of all (emitted) HAPs combined. Table 5.1-13 presents a summary of estimated maximum potential annual HAP emissions for the PMEC. As shown in this table, the total facility-wide HAP emissions are 20.9 tons per year, which is less than the MACT program major source threshold of 25 tons per year. The maximum single HAP annual emission rate is 7.1 tons per year (formaldehyde), which is also less than the MACT program single HAP major source threshold of 10 tons per years. Based on these emission rate calculations, the facility would not be subject to the MACT program. Additional information on the HAP emission factors and calculations is provided in Section 5.1.2.5.5.

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

TABLE 5.1-13
PMEC MAXIMUM POTENTIAL ANNUAL HAP EMISSIONS

Compound	CAS #	Annual Emission Rate (ton/yr)									
		CTGs & DBs	Thermal Vent Oxidizer	Flare	Gasification Plant Fugitives	Auxiliary Boiler	Power Cooling Tower	Gas/ASU Cooling Tower	Emergency Fire Pump	Emergency Generator	Total
1,3-Butadiene	106-99-0	0.00425	0	0	0	0	0	0	0.00000411	0	0.00425
Acetaldehyde	75-07-0	0.395	0.000118	0.000346	0	0	0	0	0.0000805	0.0000237	0.395
Acrolein	107-02-8	0.0632	0	0	0	0	0	0	0.00000971	0.0000074	0.0632
Antimony	7440-36-0	0.0314	0.000197	0.000576	0	0	0	0	0	0	0.0322
Arsenic	7440-38-2	0.0821	0.00104	0.00304	0	0.0000279	0.0000127	0.00000635	0	0	0.0862
Benzene	71-43-2	0.518	0.0198	0.058	0.000779	0.000293	0	0	0.000098	0.000728	0.598
Beryllium	7440-41-7	0.00642	0.00000591	0.0000174	0	0.00000167	0	0	0	0	0.00645
Cadmium	7440-43-9	0.234	0.0000394	0.000125	0	0.000154	0	0	0	0	0.234
Carbon disulfide	75-15-0	1.18	0.00302	0.00884	0.00416	0	0	0	0	0	1.2
Carbonyl sulfide	463581	0	0	0	0.00745	0	0	0	0	0	0.00745
Chlorine	7782-50-5	0	0	0	0	0	0.00635	0.00318	0	0	0.00953
Chromium, hexavalent	18540-29-9	0.00884	0.000221	0.000652	0	0.0000977	0	0	0	0	0.00981
Cobalt	7440-48-4	0.0258	0.000841	0.00246	0	0.0000117	0	0	0	0	0.0291
Cyanides	57-12-5	0.214	0.00329	0.00961	0.00122	0	0	0	0	0	0.228
Ethyl benzene	100-41-4	0.515	0.0222	0.0649	0.000000687	0	0	0	0	0	0.602
Formaldehyde	50-00-0	7.13	0.00112	0.00391	0.000000145	0.0105	0	0	0.000124	0.0000741	7.14
Hexane	110-54-3	2.79	0	0.0155	0.00000019	0.251	0	0	0	0	3.06
Hydrochloric acid	7647-01-0	0.329	0.000649	0.0019	0.0134	0	0	0	0	0	0.345
Hydrogen fluoride	7664-39-3	1.21	0.0000394	0.000115	0	0	0	0	0	0	1.21
Hydrogen sulfide	7783-06-4	0	0	0	0.511	0	0	0	0	0	0.511
Lead	7439-92-1	0.0142	0.000028	0.0000818	0	0	0.00000254	0.00000127	0	0	0.0143
Manganese	7439-96-5	0.0639	0.00166	0.00486	0	0.000053	0.00508	0.00254	0	0	0.0781
Mercury	7439-97-6	0.0293	0.00046	0.000137	0	0.0000363	0.00000127	0.000000635	0	0	0.0299
Methyl bromide	74-83-9	1.34	0.00808	0.0236	0	0	0	0	0	0	1.37
Methyl chloride	74-87-3	0	0.00414	0.0121	0	0	0	0	0	0	0.0162
Methylene chloride	75-09-2	0.0622	0.000388	0.00113	0	0	0	0	0	0	0.0637
Naphthalene	91-20-3	0.0736	0.000565	0.00166	0.0000032	0.0000851	0	0	0.0000089	0.000122	0.076
Nickel	7440-02-0	0.0776	0.00294	0.00861	0	0.000293	0	0	0	0	0.0894
Phenol	108-95-2	1.08	0.00828	0.0242	9.94E-09	0	0	0	0	0	1.11
Propylene	115-07-1	0	0	0	0	0	0	0	0.0000271	0.00262	0.00265
Propylene Oxide	75-56-9	0.286	0	0	0	0	0	0	0	0	0.286
Selenium	7784-49-2	0.0174	0.000164	0.000481	0	0.00000335	0.0000254	0.0000127	0	0	0.018
Toluene	108-88-3	1.29	0.00782	0.0229	0.0000822	0.000475	0	0	0.0000429	0.000264	1.32

TABLE 5.1-13 (CONTINUED)
PMEC MAXIMUM POTENTIAL ANNUAL HAZARDOUS AIR POLLUTANT EMISSIONS

Compound	CAS #	Annual Emission Rate (ton/yr)									
		CTGs & DBs	Thermal Vent Oxidizer	Flare	Gasification Plant Fugitives	Auxiliary Boiler	Power Cooling Tower	Gas/ASU Cooling Tower	Emergency Fire Pump	Emergency Generator	Total
Xylenes	1330-20-7	0.632	0.00887	0.0259	0.00000127	0	0	0	0.0000299	0.000181	0.667
Polycyclic Organic Matter[1]	POM	0.0000556	0.000000151	0.000000442	0	0.0000123	0	0	0.00000874	0.0000765	0.000154
Total HAPs											20.9
Maximum Single HAP											7.14

1) For the Clean Air Act Section 112 requirements each individual PAH is not a HAP, but the combination of all Polyaromatic Hydrocarbons (PAH) would be considered Polycylic Organic Matter (POM), which is a HAP.

5.1.2.5.3 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. The PMEC would be subject to these regulations. Monitoring may take the form of CEMS or calculations based on fuel sulfur monitoring or similar techniques. The requirements for CEMS are similar to those required under the NSPS except that CEMs for sources subject to 40 CFR Part 72 must meet more stringent accuracy limits during annual relative accuracy test audits.

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

5.1.2.5.4 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 and TAPs. The use of combustion controls to optimize combustion also reduces both criteria pollutants and TAPs. The BACT analysis included as Appendix B-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% opacity except for 3 minutes per hour; controls nuisance particulate fallout, fugitive dust, and odors; and limits SO_2 emissions to no more than 1000 ppm (hourly average, 7% 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% O_2.

SWCAA regulations mirror Ecology's emission limits for new sources. The SWCAA regulation's opacity standard limits the plume to 20% opacity except for 3 minutes of any hour. Particulate matter emissions are limited to 0.1 grains per dry standard cubic foot. Sulfur emissions, calculated as SO_2, are limited to 1000 ppm.

The maximum PM_{10} emission rate from each combustion turbine would be (at most) about 28 lb/hr. Given a flow rate of approximately 1 million actual cubic feet per minute (acfm) from each turbine, this emission rate corresponds to grain loadings of less than 0.01 grains/actual cubic foot (gr/acf). Adjusting for standard temperature and dry exhaust, emissions from each unit would also be less than 0.01 gr/dscf. Thus, the anticipated grain loading is less than 10 percent of the 0.1 gr/dscf allowed by the state regulation. Plume opacity associated with grain loadings this low would be less than 5 percent, which is well below the allowed 20 percent. The anticipated SO_2 concentration less would also be well below the state limit of 1000 ppm.

5.1.2.4.1 Notice of Construction and Application for Approval

State law (WAC 173-400-110) requires a NOC for the construction of new air contaminant sources in Washington. SWCAA 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.

5.1.2.4.2 Prevention of Significant Deterioration (PSD)

The PSD permit process was established by USEPA to ensure that new or expanded major stationary sources that emit criteria pollutants above a significance rate do not cause air quality in areas that currently meet the standards (i.e., attainment areas) to deteriorate significantly. These regulations require the application of BACT, and set PSD increments, which limit the increases in SO_2, NO_2 and PM concentrations that may be produced by a new source. Increments have been established for three land classifications. The most stringent increments apply to Class I areas, which include wilderness areas and national parks. The Class I area nearest to Kalama is the Mt Adams Wilderness Area, located about 95 kilometers (km) east of Kalama. 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 PMEC would be subject to PSD regulations because it would emit more than 100 tons per year of a regulated pollutant (See Table 5.1-8). Once subject to the PSD process, emissions of other pollutants that exceed specific significant emission rates must be evaluated. Annual emissions of NO_x, PM_{10}, SO_2, CO, volatile organic compounds (VOCs), and sulfuric acid mist from the PMEC would exceed the significant emission rates that trigger consideration in the PSD permit.

5.1.2.5.5Toxic and Hazardous Air Pollutants (TAPs & HAPs)

The PMEC has the potential to emit non-criteria air pollutants that are regulated federally by the CAA Section 112 and locally 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 5.1-14 identifies TAPs expected to be emitted by PMEC sources and Washington's Small Quantity Emission Rates (SQERs). If the total emissions of a given pollutant are greater than its SQER, dispersion modeling is required to determine compliance with ambient air quality criteria (Acceptable Source Impact Levels, or ASILs).

Toxic and hazardous air pollutant emissions at the PMEC would be reduced by the same process features that control criteria emissions. A large portion of the heavy metals and other undesirable constituents of the feed would be immobilized in the non-hazardous vitreous slag by-product and thereby prevented from causing adverse environmental effects. Gaseous and particle-bound compounds that may be contained in the raw syngas exiting the gasifiers would be totally or partially removed by the syngas particulate matter removal system, water scrubber, and AGR systems described in Section 2.3. In addition, the mercury removal carbon absorption beds would be designed to ensure that mercury emissions from the PMEC would be 5 percent or less of the mercury present in the feedstock as received. The following sections discuss TAP and HAP emissions from each PMEC emission unit based on the emission factors identified in Appendix B-3-2 of the September Application.

Power Generation Units

Emission rates were calculated for the various power generation operating scenarios described in Section 5.1.2.1. For operation with syngas, TAP and HAP emission rates for the combustion turbines when firing syngas were calculated using emission factors for the coal feedstock as provided by the National Energy Technology Laboratory (NETL), United State Deptartment of Energy (USDOE), *Major Environmental Aspects of Gasification-based Power Generation Technologies, Final Report,* December 2002, and test data from the Wabash River IGCC power plant. The Wabash factors for metals and hydrochloric acid were adjusted to reflect a worst-case PMEC feedstock composition considering the highest emissions from either regional petcoke or Powder River Basin (PRB) coal, which has a higher mercury content than petcoke. Combustion turbine operation with natural gas used emission factors from USEPA's AP-42 emission factor guidance document (Section 3.1: Stationary Gas Turbines).

The duct burner TAP and HAP emission rates for syngas operation were calculated using emission factors for syngas feed from the NETL report and test data from the Wabash River IGCC power plant. For duct burning using natural gas, AP-42 emission factors were used (Section 1.4: Natural Gas Combustion). Ammonia slip emissions for normal operations are based on a proposed permit limit of 5 ppmvd at 15% O_2. Table 5.1-15 presents the maximum total TAP emissions from both turbines for normal full load operations with duct burning and the fuel combination that gives the highest emission rate for each compound.

TABLE 5.1-14
SUMMARY OF PMEC TAP EMISSION RATES

Compound	CAS #	TAP Class	Emission Rate		Small Quantity Emission Rate[1]			Modeling Required?
			(lb/hr)	(lb/yr)	Class A (lb/yr)	Class B (lb/yr)	Class B (lb/hr)	
1,3-Butadiene	106-99-0	A	0.00105	8.5	0.5	-	-	Yes
Acetaldehyde	75-07-0	A	0.0924	791	50	-	-	Yes
Acrolein	107-02-8	B	0.0148	126	-	175	0.02	No
Ammonia	7664-41-7	B	37	324,000	-	17,500	2	Yes
Antimony	7440-36-0	B	0.00737	64.4	-	175	0.02	No
Arsenic	7440-38-2	A	0.0198	172	0[2]	-	-	Yes
Barium	7440-39-3	B	0.00213	14.9	-	175	0.02	No
Benzene	71-43-2	A	0.155	1,200	20	-	-	Yes
Beryllium	7440-41-7	A	0.00147	12.9	0[2]	-	-	Yes
Butane	106-97-8	B	1.02	7,130	-	43,748	5	No
Cadmium	7440-43-9	A	0.0536	468	0[2]	-	-	Yes
Carbon disulfide	75-15-0	B	0.274	2,400	-	17,500	2	No
Carbonyl sulfide	463581	B	0.0017	14.9	-	-	-	No
Chlorine	7782-50-5	B	0.00218	19.1	-	175	0.02	No
Chromium, hexavalent	18540-29-9	A	0.00233	19.6	0[2]	-	-	Yes
Cobalt	7440-48-4	B	0.00673	58.2	-	175	0.02	No
Copper	7440-50-8	B	0.000411	2.89	-	175	0.02	No
Cyanides	57-12-5	B	0.0524	456	-	1750	0.2	No
Ethyl benzene	100-41-4	B	0.14	1,200	-	22,750	2.6	No
Fluorine	7782-41-4	B	0.000261	2.29	-	175	0.02	No
Formaldehyde	50-00-0	A	1.64	14,300	20	-	-	Yes
Hexane	110-54-3	B	0.87	6,110	-	22,750	2.6	No
Hydrochloric acid	7647-01-0	B	0.0789	691	-	175	0.02	Yes
Hydrogen fluoride	7664-39-3	B	0.276	2,420	-	175	0.02	Yes
Hydrogen sulfide	7783-06-4	B	0.117	1,020	-	175	0.02	Yes
Lead	7439-92-1	A	0.00327	28.6	50	-	-	No
Manganese	7439-96-5	B	0.018	156	-	175	0.02	No
Mercury	7439-97-6	B	0.00717	59.8	-	175	0.02	No
Methyl bromide	74-83-9	B	0.314	2,740	-	175	0.02	Yes
Methyl chloride	74-87-3	B	0.0041	32.5	-	43,748	5	No
Methylene chloride	75-09-2	A	0.0146	127	50	-	-	Yes
Molybdenum	7439-98-7	B	0.000532	3.74	-	5,250	0.6	No
Naphthalene	91-20-3	B	0.0201	152	-	22,750	2.6	No
Nickel	7440-02-0	A	0.0209	179	0.5	-	-	Yes
Pentane	109-66-0	B	1.26	8,830	-	43,748	5	No
Phenol	108-95-2	B	0.255	2,230	-	10,500	1.2	No
Selenium	7784-49-2	B	0.00414	36.1	-	175	0.02	No
Silver	7440-22-4	B	8.7E-07	0.00762	-	175	0.02	No
Sulfuric acid/ Sulfates	7664-93-9 & 14808-79-8	B	4.5	40,600	-	175	0.02	Yes
Toluene	108-88-3	B	0.309	2,640	-	43,748	5	No
Vanadium	7440-62-2	B	0.00111	7.81	-	175	0.02	No
Xylenes	1330-20-7	B	0.157	1,330	-	43,748	5	No
Polyaromatic Hydrocarbons[3]	PAH	A	0.000101	0.124	0[2]	-	-	Yes

1) Small Quantity Emission Rates are defined in WAC 173-460-090(e).
2) Per WAC 173-460-090(e), TAPs with ASILs less than 0.001 $\mu g/m^3$ are required to use dispersion modeling to demonstrate compliance with the ASIL; there is not SQER.
3) PAH emission rate calculated per WAC 173-460-050(c).

TABLE 5.1-15
TAP & HAP EMISSIONS FROM POWER GENERATION UNITS

Compound	CAS #	Emission Factor				Maximum Emission Rate (Both Units)	
		CT/Syngas ($lb/10^{12}$ Btu coal)	CT/Nat Gas (lb/MMBtu)	DB/Syngas ($lb/10^{12}$ Btu)	DB/Nat Gas ($lb/10^{6}$ scf)	Short-term (lb/hr)	Annual (ton/yr)
1,3-Butadiene	106-99-0	--	0.00000043	--	--	0.000969	0.00425
Acetaldehyde	75-07-0	1.8	0.00004	1.8	--	0.0902	0.395
Acrolein	107-02-8	--	0.0000064	--	--	0.0144	0.0632
Ammonia	7664-41-7	6694	0.013	--	--	37	162
Antimony	7440-36-0	1.11	--	3	--	0.00717	0.0314
Arsenic	7440-38-2	2.4	--	15.8	0.0002	0.0187	0.0821
Barium	7440-39-3	--	--	--	0.0044	0.00156	0.00682
Benz[a]anthracene	PAH-2	0.0023	--	--	--	0.0000127	0.0000556
Benzene	71-43-2	2.4	0.000012	302	0.0021	0.118	0.518
Beryllium	7440-41-7	0.26	--	0.09	0.000012	0.00147	0.00642
Butane	106-97-8	--	--	--	2.1	0.743	3.26
Cadmium	7440-43-9	9.6	--	0.6	0.0011	0.0534	0.234
Carbon disulfide	75-15-0	46	--	46	--	0.27	1.18
Chromium, total	0-00-5	0.51	--	11.2	0.0014	0.00673	0.0295
Chromium, hexavalent	18540-29-9	0.154	--	3.36	0.0007	0.00202	0.00884
Cobalt	7440-48-4	0.26	--	12.8	0.000084	0.00589	0.0258
Copper	7440-50-8	--	--	--	0.00085	0.000301	0.00132
Cyanides	57-12-5	5.7	--	50	--	0.0489	0.214
Ethylbenzene	100-41-4	--	0.000032	338	--	0.118	0.515
Formaldehyde	50-00-0	17	0.00071	17	0.075	1.63	7.13
Hexane	110-54-3	--	--	--	1.8	0.637	2.79
Hydrochloric acid	7647-01-0	13	--	9.88	--	0.0752	0.329
Hydrogen fluoride	7664-39-3	50	--	0.6	--	0.276	1.21
Lead	7439-92-1	0.56	--	0.426	--	0.00324	0.0142
Manganese	7439-96-5	1.05	--	25.3	0.00038	0.0146	0.0639
Mercury	7439-97-6	1.2	--	0.7	0.00026	0.00668	0.0293
Methyl bromide	74-83-9	47.7	--	123	--	0.306	1.34
Methylene chloride	75-09-2	2.2	--	5.9	--	0.0142	0.0622
Molybdenum	7439-98-7	--	--	--	0.0011	0.000389	0.00171
Naphthalene	91-20-3	2.5	0.0000013	8.6	0.00061	0.0168	0.0736
Nickel	7440-02-0	0.39	--	44.7	0.0021	0.0177	0.0776
Pentane	109-66-0	--	--	--	2.6	0.92	4.03
Phenol	108-95-2	36.8	--	126	--	0.247	1.08
Propylene Oxide	75-56-9	--	0.000029	--	--	0.0654	0.286

TABLE 5.1-15 (CONTINUED)
TAP & HAP EMISSIONS FROM COMBUSTION TURBINES AND DUCT BURNERS

Compound	CAS #	Emission Factor				Maximum Emission Rate (Both Units)	
		CT/Syngas ($lb/10^{12}$ Btu coal)	CT/Nat Gas (lb/MMBtu)	DB/Syngas ($lb/10^{12}$ Btu)	DB/Nat Gas ($lb/10^{6}$ scf)	Short-term (lb/hr)	Annual (ton/yr)
Selenium	7784-49-2	0.56	--	2.5	0.000024	0.00396	0.0174
Sulfuric acid/Sulfates	7664-93-9 & 14808-79-8	572	--	3761	--	4.47	19.6
Toluene	108-88-3	0.033	0.00013	119	0.0034	0.294	1.29
Vanadium	7440-62-2	--	--	--	0.0023	0.000814	0.00357
Xylenes	1330-20-7	--	0.000064	135	--	0.144	0.632
Polyaromatic Hydrocarbons	PAH	--	0.0000022	--	--	0.00496	0.0217

1) Both short-term and annual emissions based on both turbines operating at 100% load for the entire year.

Tank Vent Oxidizer

Tank vent oxidizer TAPs emissions were calculated based on emission factors for syngas feed from the NETL report and test data from the Wabash River IGCC power plant. Table 5.1-16 presents estimated maximum short-term and annual TAP emissions from the tank vent oxidizer.

TABLE 5.1-16
TAP & HAP EMISSIONS FROM TANK VENT OXIDIZER

Compound	CAS #	Emission Factor ($lb/10^{12}$ Btu syngas)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
Acetaldehyde	75-07-0	1.8	1.2E-04	1.2E-04
Antimony	7440-36-0	3.0	2.0E-04	2.0E-04
Arsenic	7440-38-2	15.8	1.0E-03	1.0E-03
Benz[a]anthracene	56-55-3	0.0023	1.5E-07	1.5E-07
Benzene	71-43-2	302	2.0E-02	2.0E-02
Beryllium	7440-41-7	0.09	5.9E-06	5.9E-06
Cadmium	7440-43-9	0.60	3.9E-05	3.9E-05
Carbon disulfide	75-15-0	46	3.0E-03	3.0E-03
Chromium, total	0-00-5	11.2	7.3E-04	7.4E-04
Chromium, hexavalent	18540-29-9	3.4	2.2E-04	2.2E-04
Cobalt	7440-48-4	12.8	8.3E-04	8.4E-04
Cyanides	57-12-5	50	3.3E-03	3.3E-03
Ethyl benzene	100-41-4	338	2.2E-02	2.2E-02
Formaldehyde	50-00-0	17	1.1E-03	1.1E-03
Hydrochloric acid	7647-01-0	9.9	6.4E-04	6.5E-04
Hydrogen fluoride	7664-39-3	0.6	3.9E-05	3.9E-05
Lead	7439-92-1	0.43	2.8E-05	2.8E-05
Manganese	7439-96-5	25.3	1.6E-03	1.7E-03
Mercury	7439-97-6	7.0	4.6E-04	4.6E-04
Methyl bromide	74-83-9	123	8.0E-03	8.1E-03
Methyl chloride	74-87-3	63	4.1E-03	4.1E-03
Methylene chloride	75-09-2	5.9	3.8E-04	3.9E-04
Naphthalene	91-20-3	8.6	5.6E-04	5.7E-04
Nickel	7440-02-0	44.7	2.9E-03	2.9E-03
Phenol	108-95-2	126	8.2E-03	8.3E-03
Selenium	7784-49-2	2.5	1.6E-04	1.6E-04
Sulfuric acid/Sulfates	7664-93-9 & 14808-79-8	572	3.7E-02	3.8E-02
Toluene	108-88-3	119	7.7E-03	7.8E-03
Xylenes	1330-20-7	135	8.8E-03	8.9E-03

1) Short-term emissions based on a maximum operation of 65 MMBtu/hr and annual based on operations of 15 MMBtu/hr for the entire year.

Flare

As described in Section 5.1.2.1.4, the flare will operate on a natural gas-fired pilot light when the facility is operating normally, and would only flare syngas during startup or under upset conditions. As a result, short-term normal TAP emissions were calculated using AP-42 emission factors for natural gas combustion (Section 1.4: Natural Gas Combustion). Maximum annual TAP emissions from the flare were calculated based on emission factors for syngas fuel from the NETL report and test data from the Wabash River IGCC power plant, and the syngas

consumption rate described in Section 5.1.2.2. Table 5.1-17 presents the TAP emissions for the flare under normal short-term and annual average operations.

TABLE 5.1-17
NORMAL OPERATION TAP & HAP EMISSIONS FROM FLARE

Compound	CAS #	Syngas Emission Factor ($lb/10^{12}$ Btu syngas)	Natural Gas Emission Factor (lb/MMscf)	Short-term Emission Rate (lb/hr)	Annual Emission Rate (ton/yr)
Acetaldehyde	75-07-0	1.8	--	0	3.5E-04
Antimony	7440-36-0	3.0	--	0	5.8E-04
Arsenic	7440-38-2	15.8	0.0002	3.9E-07	3.0E-03
Barium	7440-39-3	--	0.0044	8.6E-06	3.8E-05
Benz[a]anthracene	56-55-3	0.0023	--	0	4.4E-07
Benzene	71-43-2	302	0.0021	4.1E-06	5.8E-02
Beryllium	7440-41-7	0.09	0.000012	2.4E-08	1.7E-05
Butane	106-97-8		2.1	4.1E-03	1.8E-02
Cadmium	7440-43-9	0.60	0.0011	2.2E-06	1.2E-04
Carbon disulfide	75-15-0	46	--	0	8.8E-03
Chromium, total	0-00-5	11.2	0.0014	2.7E-06	2.2E-03
Chromium, hexavalent	18540-29-9	3.4	0.0007	1.4E-06	6.5E-04
Cobalt	7440-48-4	12.8	0.000084	1.6E-07	2.5E-03
Copper	7440-50-8	--	0.00085	1.7E-06	7.3E-06
Cyanides	57-12-5	50	--	0	9.6E-03
Ethyl benzene	100-41-4	338	--	0	6.5E-02
Formaldehyde	50-00-0	17	0.075	1.5E-04	3.9E-03
Hexane	110-54-3	--	1.8	3.5E-03	1.5E-02
Hydrochloric acid	7647-01-0	9.9	--	0	1.9E-03
Hydrogen fluoride	7664-39-3	0.6	--	0	1.2E-04
Lead	7439-92-1	0.43	--	0	8.2E-05
Manganese	7439-96-5	25.3	0.00038	7.5E-07	4.9E-03
Mercury	7439-97-6	0.7	0.00026	5.1E-07	1.4E-04
Methyl bromide	74-83-9	123	--	0	2.4E-02
Methyl chloride	74-87-3	63	--	0	1.2E-02
Methylene chloride	75-09-2	5.9	--	0	1.1E-03
Molybdenum	7439-98-7	--	0.0011	2.2E-06	9.4E-06
Naphthalene	91-20-3	8.6	0.00061	1.2E-06	1.7E-03
Nickel	7440-02-0	44.7	0.0021	4.1E-06	8.6E-03
Pentane	109-66-0	--	2.6	5.1E-03	2.2E-02
Phenol	108-95-2	126	--	0	2.4E-02
Selenium	7784-49-2	2.5	0.000024	4.7E-08	4.8E-04
Sulfuric acid/Sulfates	7664-93-9 & 14808-79-8	3,761	--	0	7.2E-01
Toluene	108-88-3	119	0.0034	6.7E-06	2.3E-02
Vanadium	7440-62-2	--	0.0023	4.5E-06	2.0E-05
Xylenes	1330-20-7	135	--	0	2.6E-02

1) Short-term and long-term emissions based on normal annual flare operations of 50 MMBtu/hr for the entire year. The syngas consumption rate includes normal pilot operations, plant/gasifier startups, shutdown deslag flaring and routine flaring.

Auxiliary Boiler

Emissions of TAPs from the auxiliary boiler were calculated based on USEPA AP-42 emission factors for natural gas-fired boilers and the maximum rated capacity of the boiler (130 MMBtu/hr). Maximum annual emissions were based on an annual capacity factor for this boiler of 25 percent. Table 5.1-18 presents the TAP emissions for the auxiliary boiler.

TABLE 5.1-18
TAP & HAP EMISSIONS FROM AUXILIARY BOILER

Compound	CAS #	Emission Factor ($lb/10^6$ scf)	Short-term Emission Rate (lb/hr)	Annual Emission Rate (ton/yr)
Arsenic	7440-38-2	2.00E-04	2.55E-05	2.8E-05
Barium	7440-39-3	4.40E-03	5.61E-04	6.1E-04
Benzene	71-43-2	2.10E-03	2.68E-04	2.9E-04
Beryllium	7440-41-7	1.20E-05	1.53E-06	1.7E-06
Butane	106-97-8	2.10E+00	2.68E-01	2.9E-01
Cadmium	7440-43-9	1.10E-03	1.40E-04	1.5E-04
Chromium	7440-47-3	1.40E-03	1.78E-04	2.0E-04
Cobalt	7440-48-4	8.40E-05	8.92E-05	9.8E-05
Copper	7440-50-8	8.50E-04	1.07E-05	1.2E-05
Formaldehyde	50-00-0	7.50E-02	1.08E-04	1.2E-04
Hexane	110-54-3	1.80E+00	9.56E-03	1.0E-02
Manganese	7439-96-5	3.80E-04	2.29E-01	2.5E-01
Mercury	7439-97-6	2.60E-04	4.84E-05	5.3E-05
Molybdenum	7439-98-7	1.10E-03	3.31E-05	3.6E-05
Naphthalene	91-20-3	6.10E-04	1.40E-04	1.5E-04
Nickel	7440-02-0	2.10E-03	7.77E-05	8.5E-05
Pentane	109-66-0	2.60E+00	2.68E-04	2.9E-04
Selenium	7782-49-2	2.40E-05	3.31E-01	3.6E-01
Toluene	108-88-3	3.40E-03	3.06E-06	3.3E-06
Vanadium	7440-62-2	2.30E-03	4.33E-04	4.7E-04
Benzo(a)pyrene	PAH	1.20E-06	2.93E-04	3.2E-04
Benz(a)anthracene	PAH	1.80E-06	1.53E-07	1.7E-07
Benzo(b)fluoranthene	PAH	1.80E-06	2.29E-07	2.5E-07
Chrysene	PAH	1.80E-06	2.29E-07	2.5E-07
Dibenzo(a,h)anthracene	PAH	1.20E-06	2.29E-07	2.5E-07
Indeno(1,2,3-cd)pyrene	PAH	1.80E-06	1.53E-07	1.7E-07
2-Methylnaphthalene	PAH	2.40E-05	2.29E-07	2.5E-07
3-Methylchloranthrene	PAH	1.80E-06	3.06E-06	3.3E-06
7,12-Dimethylbenz(a)anthracene	PAH	1.60E-05	2.29E-07	2.5E-07
Acenaphthene	PAH	1.80E-06	2.04E-06	2.2E-06
Acenaphthylene	PAH	1.80E-06	2.29E-07	2.5E-07
Anthracene	PAH	2.40E-06	2.29E-07	2.5E-07
Benzo(g,h,i)perylene	PAH	1.20E-06	3.06E-07	3.3E-07
Benzo(k)fluoranthene	PAH	1.80E-06	1.53E-07	1.7E-07
Fluoranthene	PAH	3.00E-06	2.29E-07	2.5E-07
Fluorene	PAH	2.80E-06	3.82E-07	4.2E-07
Phenanathrene	PAH	1.70E-05	3.57E-07	3.9E-07
Pyrene	PAH	5.00E-06	2.17E-06	2.4E-06

1) Short-term emissions based on normal full load operations. Annual emission based on a maximum annual capacity factor of 25%.

Emergency Diesel Engines

Emissions of TAPs from the emergency generator and the fire pump were calculated based on USEPA AP-42 emission factors for large and small internal combustion diesel engines, respectively. Maximum annual emissions were based on annual operations of 100 hours of this equipment for testing purposes only. Table 5.1-19 presents TAP emission rates for the emergency fire pump, and Table 5.1-20 presents the TAP emission rates for the emergency generator.

TABLE 5.1-19
TAP & HAP EMISSIONS FROM EMERGENCY FIRE WATER PUMP

Compound	CAS #	Emission Factor ($lb/10^6$ Btu)	Short-term Emission Rate (lb/hr)	Annual Emission Rate (ton/yr)
1,3-Butadiene	106-99-0	3.91E-05	8.21E-05	4.11E-06
Acetaldehyde	75-07-0	7.67E-04	1.61E-03	8.05E-05
Acrolein	107-02-8	9.25E-05	1.94E-04	9.71E-06
Benzene	71-43-2	9.33E-04	1.96E-03	9.80E-05
Formaldehyde	50-00-0	1.18E-03	2.48E-03	1.24E-04
Naphthalene	91-20-3	8.48E-05	1.78E-04	8.90E-06
Propylene	115-07-1	2.58E-04	5.42E-04	2.71E-05
Toluene	108-88-3	4.09E-04	8.59E-04	4.29E-05
Xylenes	1330-20-7	2.85E-04	5.99E-04	2.99E-05
Benzo(a)pyrene	PAH	1.88E-07	3.95E-07	1.97E-08
Benzo(a)anthracene	PAH	1.68E-06	3.53E-06	1.76E-07
Benzo(b)fluoranthene	PAH	9.91E-08	2.08E-07	1.04E-08
Chrysene	PAH	3.53E-07	7.41E-07	3.71E-08
Dibenz(a,h)anthracene	PAH	5.83E-07	1.22E-06	6.12E-08
Indeno(1,2,3-cd)pyrene	PAH	3.75E-07	7.88E-07	3.94E-08
Acenaphthene	PAH	1.42E-06	2.98E-06	1.49E-07
Acenaphthylene	PAH	5.06E-06	1.06E-05	5.31E-07
Anthracene	PAH	1.87E-06	3.93E-06	1.96E-07
Benzo(g,h,i)perylene	PAH	4.89E-07	1.03E-06	5.13E-08
Benzo(k)fluoranthene	PAH	1.55E-07	3.26E-07	1.63E-08
Fluoranthene	PAH	7.61E-06	1.60E-05	7.99E-07
Fluorene	PAH	2.92E-05	6.13E-05	3.07E-06
Phenanthrene	PAH	2.94E-05	6.17E-05	3.09E-06
Pyrene	PAH	4.78E-06	1.00E-05	5.02E-07

1) Short-term emissions based on normal full load operations. Annual emission based on 100 hours of engine testing.

TABLE 5.1-20
TAP & HAP EMISSIONS FROM EMERGENCY GENERATOR

Compound	CAS #	Emission Factor ($lb/10^6$ Btu)	Short-term Emission Rate (lb/hr)	Annual Emission Rate (ton/yr)
Acetaldehyde	75-07-0	2.52E-05	4.73E-04	2.37E-05
Acrolein	107-02-8	7.88E-06	1.48E-04	7.40E-06
Benzene	71-43-2	7.76E-04	1.46E-02	7.28E-04
Formaldehyde	50-00-0	7.89E-05	1.48E-03	7.41E-05
Naphthalene	91-20-3	1.30E-04	2.44E-03	1.22E-04
Propylene	115-07-1	2.79E-03	5.24E-02	2.62E-03
Toluene	108-88-3	2.81E-04	5.28E-03	2.64E-04
Xylenes	1330-20-7	1.93E-04	3.62E-03	1.81E-04
Benzo(a)pyrene	PAH	2.57E-07	4.82E-06	2.41E-07
Benz(a)anthracene	PAH	6.22E-07	1.17E-05	5.84E-07
Benzo(b)fluoranthene	PAH	1.11E-06	2.08E-05	1.04E-06
Chrysene	PAH	1.53E-06	2.87E-05	1.44E-06
Dibenz(a,h)anthracene	PAH	3.46E-07	6.50E-06	3.25E-07
Indeno(1,2,3-cd)pyrene	PAH	4.14E-07	7.77E-06	3.89E-07
Acenaphthene	PAH	4.68E-06	8.79E-05	4.39E-06
Acenaphthylene	PAH	9.23E-06	1.73E-04	8.66E-06
Anthracene	PAH	1.23E-06	2.31E-05	1.15E-06
Benzo(g,h,i)perylene	PAH	5.56E-07	1.04E-05	5.22E-07
Benzo(k)fluoranthene	PAH	2.18E-07	4.09E-06	2.05E-07
Fluoranthene	PAH	4.03E-06	7.57E-05	3.78E-06
Fluorene	PAH	1.28E-05	2.40E-04	1.20E-05
Phenanthrene	PAH	4.08E-05	7.66E-04	3.83E-05
Pyrene	PAH	3.71E-06	6.97E-05	3.48E-06

1) Short-term emissions based on normal full load operations. Annual emission based on 100 hours of engine testing.

Cooling Towers

Cooling towers for both the power block and gasifier/ASU unit would emit small quantities of TAPs. These TAPs come primarily from the inorganic material found in the makeup water. The TAP emissions were estimated from the concentrations of TAPs found in the Kalama well water analysis, application of a drift rate of 0.0005 percent of the tower circulating water and continuous operation at 100 percent load for both turbines. Table 5.1-21 presents the estimated total TAP emissions from each cooling tower.

TABLE 5.1-21
TAP & HAP EMISSIONS FROM THE COOLING TOWERS

Compound	CAS #	Emission Factor (ppmw)	Short-term Emission (lb/hr)	Annual Emission (ton/yr)
Power Block Cooling Tower				
Arsenic	7440-38-2	0.005	2.90E-06	1.27E-05
Chlorine	7782-50-5	2.5	1.45E-03	6.35E-03
Fluorine	7782-41-4	0.3	1.74E-04	7.62E-04
Lead	7439-92-1	0.001	5.80E-07	2.54E-06
Manganese	7439-96-5	2	1.16E-03	5.08E-03
Mercury	7439-97-6	0.0005	2.90E-07	1.27E-06
Selenium	7784-49-2	0.01	5.80E-06	2.54E-05
Silver	7440-22-4	0.001	5.80E-07	2.54E-06
Gasification/ASU Cooling Tower				
Arsenic	7440-38-2	0.005	1.45E-06	6.35E-06
Chlorine	7782-50-5	2.5	7.25E-04	3.18E-03
Fluorine	7782-41-4	0.3	8.70E-05	3.81E-04
Lead	7439-92-1	0.001	2.90E-07	1.27E-06
Manganese	7439-96-5	2	5.80E-04	2.54E-03
Mercury	7439-97-6	0.0005	1.45E-07	6.35E-07
Selenium	7784-49-2	0.01	2.90E-06	1.27E-05
Silver	7440-22-4	0.001	2.90E-07	1.27E-06

Fugitive Equipment Leaks

TAP emissions associated with normal equipment leakage at the PMEC have been estimated using U.S. USEPA fugitive emission factors for valve seals, pump and compressor seals, pressure relief valves, flanges, and similar equipment.[3] Emission estimates are based on conservative equipment counts based on piping and instrumentation diagrams (P&IDs) for a typical 600 MW E-Gas IGCC project. TAP emission factors for each process stream are from the Wabash River gasification facility test results and ConocoPhillips/Fluor material balance calculations. TAP emissions from equipment leakage are presented in Table 5.1-22.

Note that the emission rate of fugitive hydrogen sulfide (H2S) from the PMEC acid removal equipment has been derived based on the air toxics modeling analysis presented in Section 5.1.3.5. Specifically, the H_2S emission rate has been selected at a value that just complies with the Washington ASIL for this pollutant, based on the modeling results. Although the precise method of achieving a compliant emission rate has not yet been determined, PMEC would implement a combination of component design enhancements and leak detection and repair procedures to ensure that the maximum predicted ambient H2S impact would be below the 0.9 ug/m3 ASIL.

[3] Protocol for Equipment Leak Estimates, U.S EPA 453-R95-017, November 1995

TABLE 5.1-22
TAP & HAP EMISSIONS FROM FUGITIVE EQUIPMENT LEAKS

Compound	CAS #	Short-term Emission Rate (lb/hr)	Annual Emission Rate (ton/yr)
Ammonia	7664-41-7	2.88E-02	1.26E-01
Benzene	71-43-2	1.78E-04	7.79E-04
Carbon disulfide	75-15-0	9.50E-04	4.16E-03
Carbonyl sulfide	463581	1.70E-03	7.45E-03
Cyanides	57-12-5	2.78E-04	1.22E-03
Ethyl benzene	100-41-4	1.57E-07	6.87E-07
Formaldehyde	50-00-0	3.30E-08	1.45E-07
Hexane	110-54-3	4.33E-08	1.90E-07
Hydrochloric acid	7647-01-0	3.06E-03	1.34E-02
Hydrogen sulfide	7783-06-4	1.17E-01	5.11E-01
Naphthalene	91-20-3	7.30E-07	3.20E-06
Phenol	108-95-2	2.27E-09	9.94E-09
Toluene	108-88-3	1.88E-05	8.22E-05
Xylenes	1330-20-7	2.89E-07	1.27E-06

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 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 PMEC 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.[4]

5.1.3.1 Model Selection

Geomatrix reviewed regulatory modeling techniques to select the most appropriate air quality dispersion model to simulate dispersion of air pollutants emitted by the PMEC for a near-field air quality impact analysis. The selection of a modeling tool is influenced by the potential for exhaust plumes from point sources to be influenced by nearby on-site structures and to impact complex terrain. The terrain at and immediately surrounding the facility, as well as in the north and east portions of the modeling domain, is relatively flat, however, intermediate and complex terrain exists in the southwest portion of the domain. The heights of proposed and existing structures, and the proposed cogeneration unit stack height, suggests that there is the potential for exhaust plume downwash to occur.

4 U.S. EPA, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting. October, 1990.

In December 2006, AERMOD superseding the ISCST3 air dispersion model, and became 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) for complex source configurations and sources subject to exhaust plume downwash. AERMOD incorporates numerical plume rise algorithms (called the PRIME algorithm) that include the downwash effects a structure may have on an exhaust plume implicitly rather than using the wind tunnel based empirical algorithms of ISCST3. Importantly, the PRIME algorithm also treats the geometry of upwind and downwind structures and their relationship to the emission point more precisely, and is able to calculate concentrations within building cavities.

AERMOD was selected for the modeling analysis primarily because it is the most up-to-date dispersion model currently available. Additionally, the modeling domains and source configurations 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 pollutants and TAPs using the regulatory defaults in addition to the options and data discussed in this section.

5.1.3.2.1 Model Setup and Application

The most recent version of AERMOD (Version 04300) was applied with the default options for dispersion that depend on local meteorological data, regional upper air data, and the local physical characteristics of land use surrounding the facility. AERMOD contains several options for urban dispersion that were not selected for these analyses. The facility is located near, Kalama, Washington, and the majority of the study domain is agricultural land, rangeland, or forest. The effects of surface roughness and other physical characteristics associated with the types of land use in the modeling domain were included in the analysis as part of the meteorological database, described in Section 5.1.3.4.

5.1.3.2.2 Averaging Periods

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

5.1.3.2.3 Chemical Transformations

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

5.1.3.3 Elevation Data and Receptor Network

Terrain elevations for receptors and emission sources were prepared using digital elevation models (DEMs) developed by the United States Geological Survey (USGS) of 7.5-minute quadrangles obtained from the internet (http://www.mapmart.com). These data have a horizontal spatial resolution of 10 meters (m). Terrain heights surrounding the facility indicate that some of

the receptors used in the simulations were located in intermediate or complex terrain (above stack or plume height).

As discussed in Section 5.1.2.1.8, feedstock will occasionally be delivered by ship. Because the ship will be present intermittently, modeling simulations were developed both with and without emissions attributable to ship hoteling and cargo unloading. Ships will operate at an adjacent Port of Kalama dock, which was considered "on-site" for purposes of placing model receptors when a ship was present. For scenarios in which no ship was present, ship hoteling and unloading emissions were assumed to be zero, and receptors were placed on port property.

For the preliminary analysis, four nested grids were used to model PMEC, with the grid closest to the proposed facility having the closest spacing (25 meters or 82 feet), the next closest with 50-meter (164-foot) spacing, then a 200-meter (656-foot) grid, and, finally, an outer grid with receptors every 500 meters (1,640 feet). Also, receptors were placed every 25 meters (82 feet) along the property boundary. The preliminary receptor locations are shown in Figure 5.1-1 for simulations with ship emissions, and in Figure 5.1-2 for simulations without ship emissions. Following the preliminary modeling analysis, additional fine receptors (i.e., 25-meter spacing) receptors were added as needed to fully resolve the location and magnitude of the maximum predicted concentrations. Additional coarse receptors (i.e., 500-meter spacing) were added outside the preliminary domain to ensure that the most distant receptor exceeding a given threshold is within the modeling domain.

5.1.3.4 Meteorological Data

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

A meteorological station operated by TRC Consultants, Inc for Noveon Chemical (formerly Kalama Chemical and BF Goodrich), approximately 3 km south-southeast of the proposed facility, collects hourly wind speed, wind direction, solar radiation, temperature, vertical differential temperature (delta-T), and lateral wind turbulence (sigma-theta, or $\sigma\theta$).[5]

5 TRC Environmental Consultants, 1996. Meteorological Data Report, Kalama, Washington, Annual 1995. TRC, 11 Inverness Drive East, Englewood, CO 80112, TRC Project 16826-01, April 25, 1996

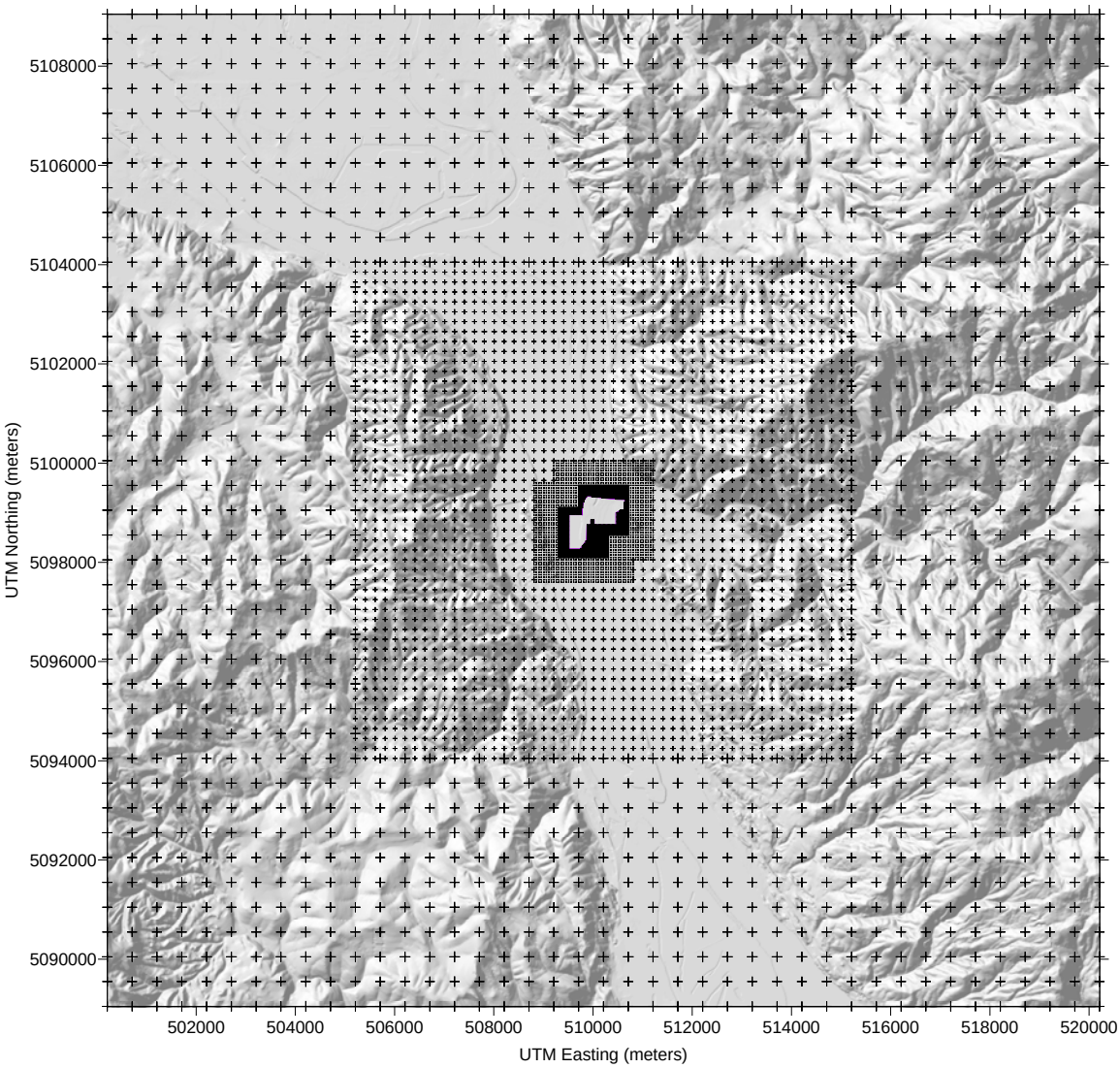


Figure 5.1-1. Preliminary Receptor Locations With Ship Emissions

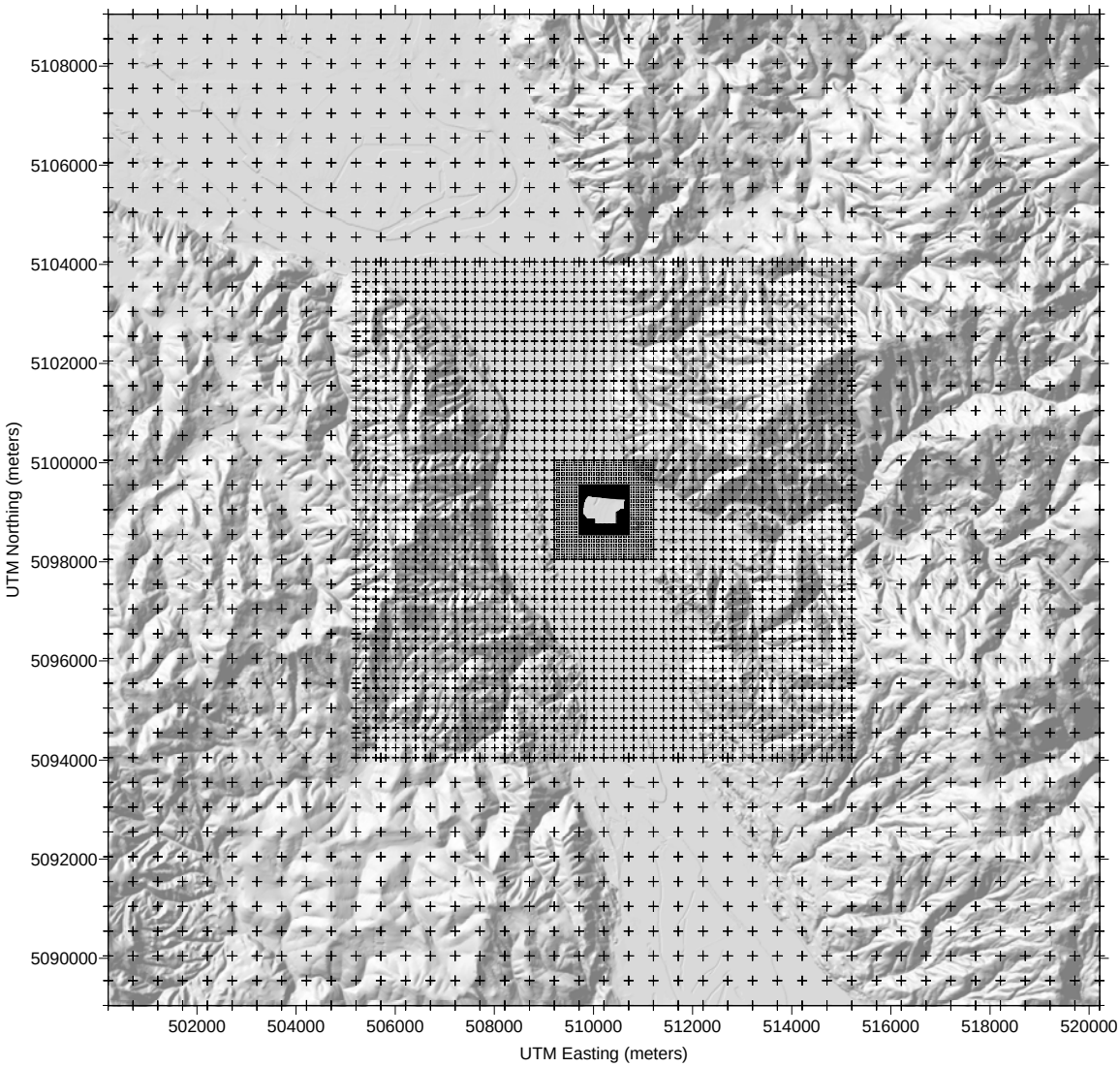


Figure 5.1-2. Preliminary Receptor Locations Without Ship Emissions

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

Figure 5.1-3 shows a wind rose constructed from the 1995 meteorological database. As shown in the figure, the winds are bimodal, following the general north-south orientation of this portion of the Columbia River Valley. The average wind velocity for 1995 was 2.7 meters per second (m/s), and periods of calm wind are rare, occurring for less than 1 percent of the observations. Light winds tend to come up the valley from the north, while the highest wind velocities are from the south and southwest. The winds in the Noveon dataset are quite different from those observed at low level stations such as those located at Longview or Portland airports, and reflect the influence of the local topography.

Additional meteorological variables and geophysical parameters are required by the dispersion modeling analysis to estimate the surface energy fluxes and construct boundary layer profiles. Surface characteristics including the surface roughness length, albedo, and Bowen ratio were assigned on a sector-by-sector basis using land use within 3 km of the proposed facility site. The USGS 1992 National Land Cover (NLCD92) land use data set used in the analysis has a 30-meter mesh size and over 30 land use categories.[6]

5.1.3.5 Existing Air Quality

The USEPA maintains a database that contains ambient air quality data from monitoring sites across the United States. The USEPA AirData website[7] allows users to collect yearly summarized air quality data for specific ambient monitoring sites. Air quality measurement data were collected for 2004 and 2005 for monitoring stations located in Washington and Oregon. The air quality data search was narrowed to five monitoring stations: two sites located in Vancouver, Washington; one site in Longview, Washington; one site in Seattle, Washington; and one site in Portland, Oregon. In general, these stations are located in or near urban areas, or close to specific large air pollution sources where there may be existing air quality problems.

6 The USGS NLCD92 data set is described and can be accessed at http://landcover.usgs.gov/natllandcover.php.

7 The U.S. EPA AirData website is described and can be accessed at http://www.usepa.gov/air/data/info.html

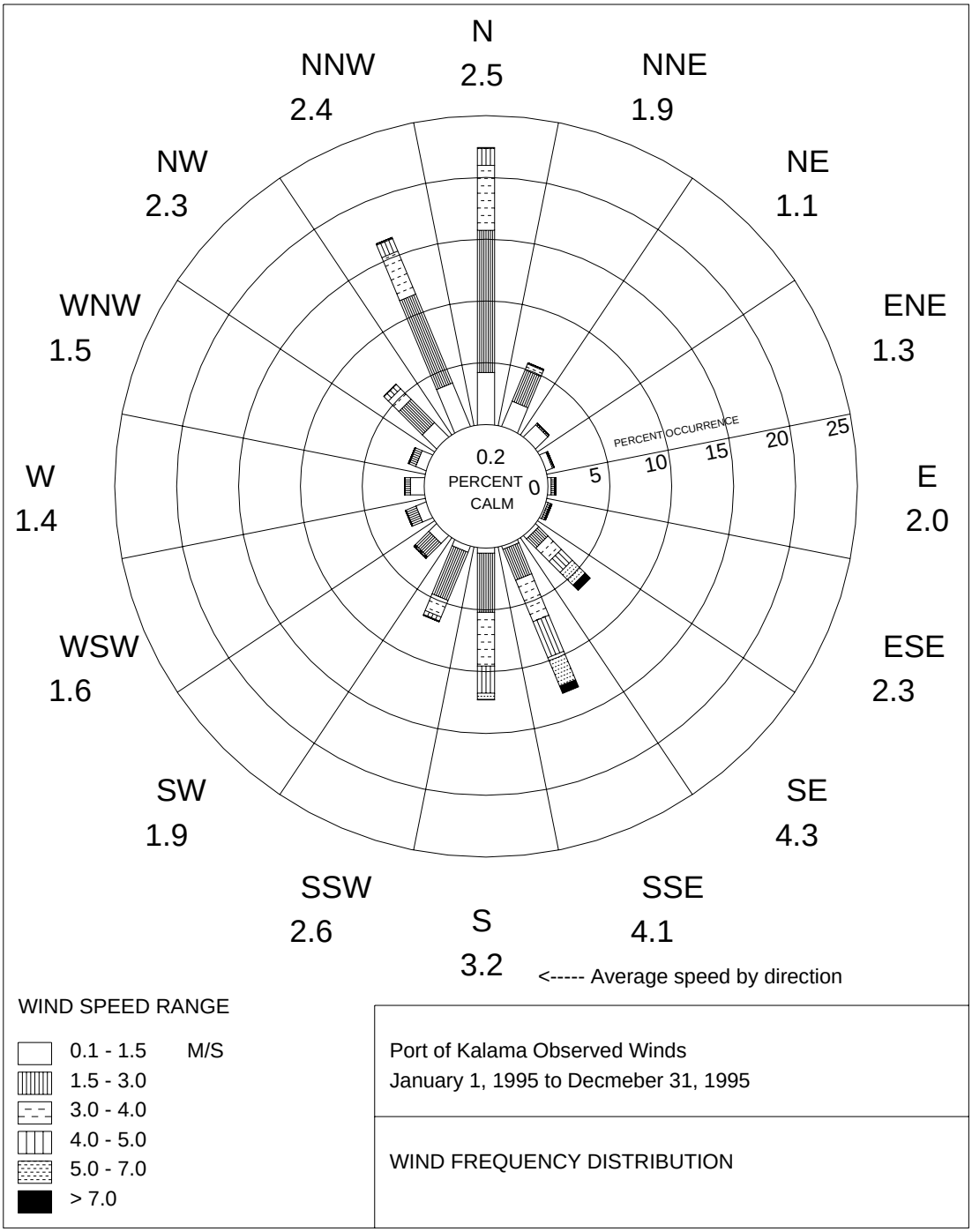


Figure 5.1-3. Port of Kalama Wind Rose

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. Cowlitz County, where the proposed facility will be located, is in attainment for all air pollutants.

The 2004 and 2005 monitoring data from the five ambient monitoring stations were used to characterize existing air quality at the site. A summary of these data is presented in Table 5.1-23.

TABLE 5.1-23
AMBIENT AIR QUALITY MONITORING DATA

Concentrations in micrograms per cubic meter (µg/m^3)

Pollutant	Averaging Period	Data Source[1]	Maximum Concentration[2]			Ambient Standard[3]
			2004	2005	Average	
PM10	24 Hours	a	39	77	58	150
	Annual	a	17	23	20	50
PM2.5	24 Hours	b	45	34	39.5	65
	Annual	b	10.1	8.7	9.4	15
SO2	1 Hour	c	115.1	157.0	136.1	1,050
	3 Hours	c	73.3	117.7	96.8	1,300
	24 Hours	c	36.6	49.7	44.5	262
	Annual	c	10.5	7.8	9.2	52
SO2	1 Hour	d		39.2	39.2	1,050
	3 Hours	d		31.4	31.4	1,300
	24 Hours	d		15.7	15.7	262
	Annual	d		5.2	5.2	52
Ozone	1 Hour	d	170.7	141.3	157.0	235[4]
	8 Hours	d	141.3	121.7	131.5	157[5]
NO2	Annual	d	18.8	20.7	20.7	94
CO	1 Hour	e	7326.2	8242.0	7784.1	40,000
	8 Hours	e	5723.6	5609.2	5723.6	10,000

1 Data sources are as follows:
a - Longview, WA (254 Oregon Wy)
b - Vancouver, WA (8205 E 4th Plain Blvd)
c - Seattle, WA (Beacon Hill, WA)
d - Portland, OR (5824 SE Lafayette)
e - Vancouver, WA (2101 E 4th Plain Blvd)

2 From USEPA AIRS database (http://www.epa.gov/air/data/info.html) in February 2006.

3 The most stringent standard from among NAAQS/WAAQS/OAAQS. SO2, Ozone, NO2, and CO standards have been converted from ppm.

4 Federal 1-hour ozone standard was revoked in all areas except 14 remaining nonattainment areas. The federal and the PSCAA 1-hour standard lapsed on June 15, 2005.

5 Attainment based on 3-year average of the 4th highest daily maximum 8-hour ozone concentration at each monitoring location

All observed pollutant concentrations at these monitoring sites are less than the NAAQS and both the WAAQS and Oregon state ambient air quality standards (OAAQS):

- NO_2 was monitored in Portland, where the maximum annual concentration was less than 22 percent of the NAAQS.
- CO was monitored in Vancouver, where the maximum concentrations were less than 55 percent of the NAAQS.
- The data in Table 5.1-23 indicate industrial sources do not contribute significant amounts of SO_2 in the area. SO_2 was monitored in Portland and Seattle. The maximum concentrations were less than 20 percent of the NAAQS.
- The maximum hourly ozone concentrations monitored in Portland were approximately 72 percent of the 1-hour NAAQS.
- PM_{10} concentrations (usually associated with wood smoke, fugitive dust, and combustion sources) were monitored in Longview, where maximum concentrations were less than 51 percent of the NAAQS.
- Ignoring temporal and spatial averaging, $PM_{2.5}$ was monitored in Vancouver, where maximum concentrations were about 69 percent of the annual and 67 percent of the 24-hour $PM_{2.5}$ standards.

5.1.3.6 Emission Source Release Parameters

Figure 5.1-4 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 5.1-24. A single fugitive source (gasification plant fugitive emissions), was represented in the modeling analysis by two volume sources; the parameters used for those sources are shown in Table 5.1-25.

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 PMEC were used to prepare data for BPIP-PRIME, which provides the necessary input data for AERMOD. Figure 5.1-4 shows the configuration of significant structures that were used to develop the BPIP-PRIME input files, and Table 5.1-26 presents the heights of the significant structures included in the simulations.

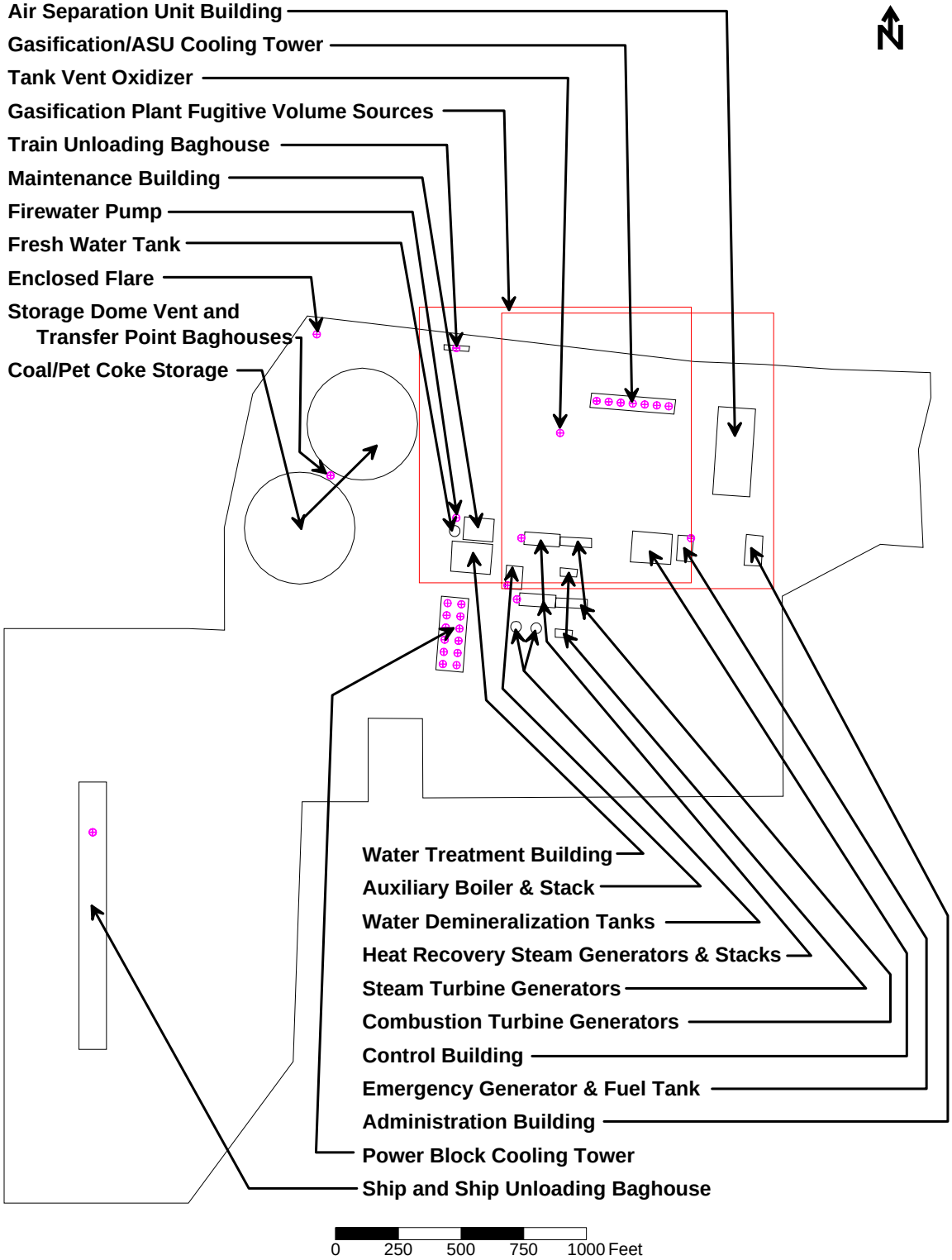


Figure 5.1-4. Emission Sources and Significant Structures Included in the Class II Modeling Simulation

TABLE 5.1-24
POINT SOURCE RELEASE PARAMETERS

Source[1]	Number of Sources	Scenario[2]	Stack Base Elev. (m)	Stack Height (m)	Exhaust Temp. (K)	Exit Vel. (m/s)	Stack Diam. (m)
CTG/HRSG	2	CTG (100%) - SG/HRSG - SG	3.66/3.56	45.72	366.48	19.89	6.096
CTG/HRSG	2	CTG (100%) - SG/HRSG - NG	3.66/3.56	45.72	366.48	19.4	6.096
CTG/HRSG	2	CTG (100%) - NG/HRSG - NG	3.66/3.56	45.72	366.48	19.5	6.096
CTG	2	CTG (100%) - SG	3.66/3.56	45.72	394.26	18.434	6.096
CTG	2	CTG (100%) - NG	3.66/3.56	45.72	394.26	20.568	6.096
CTG	2	CTG (70%) - SG	3.66/3.56	45.72	366.48	15.572	6.096
CTG	2	CTG (70%) - NG	3.66/3.56	45.72	366.48	15.281	6.096
Tank Vent Oxidizer	1	All	3.66	64.008	579.82	8.462	1.8288
Auxiliary Boiler	1	All	3.66	12.192	422.04	9.702	1.524
Enclosed Flare	1	Normal - Short Term	4.57	30.48	1144.26	0.186	15.24
Enclosed Flare	1	Normal - Annual	4.57	30.48	1144.26	8.021	15.24
Enclosed Flare	1	Startup	4.57	30.48	1144.26	8.021	15.24
Enclosed Flare	1	Upset	4.57	30.48	1144.26	17.076	15.24
Emergency Generator	1	All	3.05	9.096	622	50.152	0.4064
Firewater Pump	1	All	3.96	3	622	57.445	0.127
Power Block CT	12	All	3.7	14.63	313.15	8.137	10.058
Gasification/ASU CT	7	All	3.6	14.63	313.15	8.137	10.058
Storage Dome Vent. BH	1	All	4.57	45.72	293.15	20.03	3
Train Unloading BH	1	All	4.56	8.534	293.15	26.289	2
Ship Unloading BH	1	All	3.66	8.23	293.15	15.023	1
Transfer Point BH	1	All	4.57	45.72	293.15	15.023	1
Ship Hotelling	1	All	0	35.1	622	50.152	0.4064

1 CTG = Combustion Gas Turbine, HRSG = Heat Recovery Steam Generator, CT = Cooling Tower

2 The percentage following CTG indicates the percent load; SG = SynGas, NG = Natural Gas

TABLE 5.1-25
VOLUME SOURCE RELEASE PARAMETERS

Elevations and dimensions in meters (m)

Source	Number of Sources	Elevation	Release Height	Initial σy	Initial σz
Gasification Plant Fugitives	2	3.4	9.14	76.7	4.25

TABLE 5.1-26
HEIGHTS AND ELEVATIONS OF SIGNIFICANT ON-SITE STRUCTURES

Heights and elevations in meters (m)

Structure	Base Elevation	Height
Steam Turbine Generator North	3.4	12.2
Steam Turbine Generator South	3.4	12.2
Combustion Turbine Generator North	3.4	6.1
Combustion Turbine Generator South	3.4	6.1
Heat Recovery Steam Generator North	3.7	24.4
Heat Recovery Steam Generator South	3.6	24.4
Air Separation Unit (ASU) Building	4.0	9.1
Coal/Pet Coke Unloading	4.6	8.5
Auxiliary Boiler	3.7	9.1
Administration Building	3.4	4.6
Control Building	3.4	4.6
Emergency Generator & Fuel Tank	3.1	6.1
Water Treatment Building	4.0	9.1
Maintenance Building	4.0	6.1
Cooling Tower	3.9	12.2
Gasification/ASU Cooling Tower	3.7	12.2
Coal/Petroleum Coke Storage	4.6	47.2
Coal/Petroleum Coke Storage	4.6	47.2
Demineralization Storage Tank	3.5	12.2
Water Demineralization Tank	3.4	3.7
Fresh Water Tank	4.0	9.1
Feedstock Delivery Ship	3.7	9.1

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 Analysis Results

To evaluate the potential ambient air pollutant concentrations (i.e., impacts on air quality) attributable to the PMEC, the emission rates associated with the seven normal operating scenarios described in Section 5.1.2.1 were applied in the dispersion modeling analyses. Table 5.1-27 summarizes the maximum concentrations predicted by the modeling simulations, and compares them to both the applicable monitoring de minimis concentrations and the Significant Impact Levels (SILs) established in WAC 173-400-113(3). The SILs represent incremental, project-specific impact levels that the State of Washington accepts as insignificant with respect to maintaining compliance with the NAAQS, WAAQS (OAAQS are no more stringent than the corresponding WAAQS), and PSD increments.

TABLE 5.1-27
MAXIMUM PREDICTED PMEC-ONLY
CRITERIA POLLUTANT CONCENTRATIONS

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Pollutant	Averaging Period	Maximum Concentration[1]	SIL[2]	Over the SIL?
CO	1-Hour	433	2,000	No
	8-Hour	103	500	No
NO_2	Annual	0.97	1	No
PM_{10}	24-Hour	7.34	5	Yes
	Annual	0.40	1	No
SO_2	1-Hour	162	30	Yes
	3-Hour	69.5	25	Yes
	24-Hour	6.56	5	Yes
	Annual	0.26	1	No

1 Maximum from all normal operating scenarios, including those with and without ship-associated emissions.

2 SIL = Significant Impact Level, from WAC 173-400-113(3).

As shown in Table 5.1-27, the predicted 24-hour average PM_{10} as well as the 1-hour, 3-hour, and 24-hour average SO2 concentrations exceeded the applicable SILs. None of the monitoring de minimis concentrations were exceeded. Short-term average PM_{10} and SO_2 emissions attributable to the PMEC required further analysis to determine compliance with applicable ambient air quality standards and PSD increments, which is described in the following section. Based on preliminary results, additional receptors with 500-meter spacing were placed outside the initial domain in order to resolve the extent of the receptors exceeding the 1-hour and 3-hour average SO_2 SILs. Additional receptor grids with 25-meter spacing were also placed wherever a predicted maximum concentration was located in a receptor grid with less than 25-meter spacing. The final receptors used for the 1- and 3-hour SO_2 analyses, as well as those added to resolve maxima in receptor grids with less than 25-meter spacing, are shown in Figure 5.1-5. The added fine mesh grids were processed in separate modeling simulations solely for purposes of more fully resolving the maximum predicted concentrations.

Table 5.1-28 presents the results of the TAP modeling analysis. As shown in this table, the simulations demonstrated that the PMEC TAP emissions are expected to comply with all applicable ASILs.

5.1.3.8 Ambient Standard and PSD Increment Analysis

As indicated in the previous section, model simulations of emissions attributable to PMEC predicted that ambient 24-hour average PM_{10} and 1-hour, 3-hour, and 24-hour SO_2 concentrations will exceed the applicable SILs. As a result, a cumulative impact analysis is required to determine compliance with ambient air quality standards and PSD Class II increments.

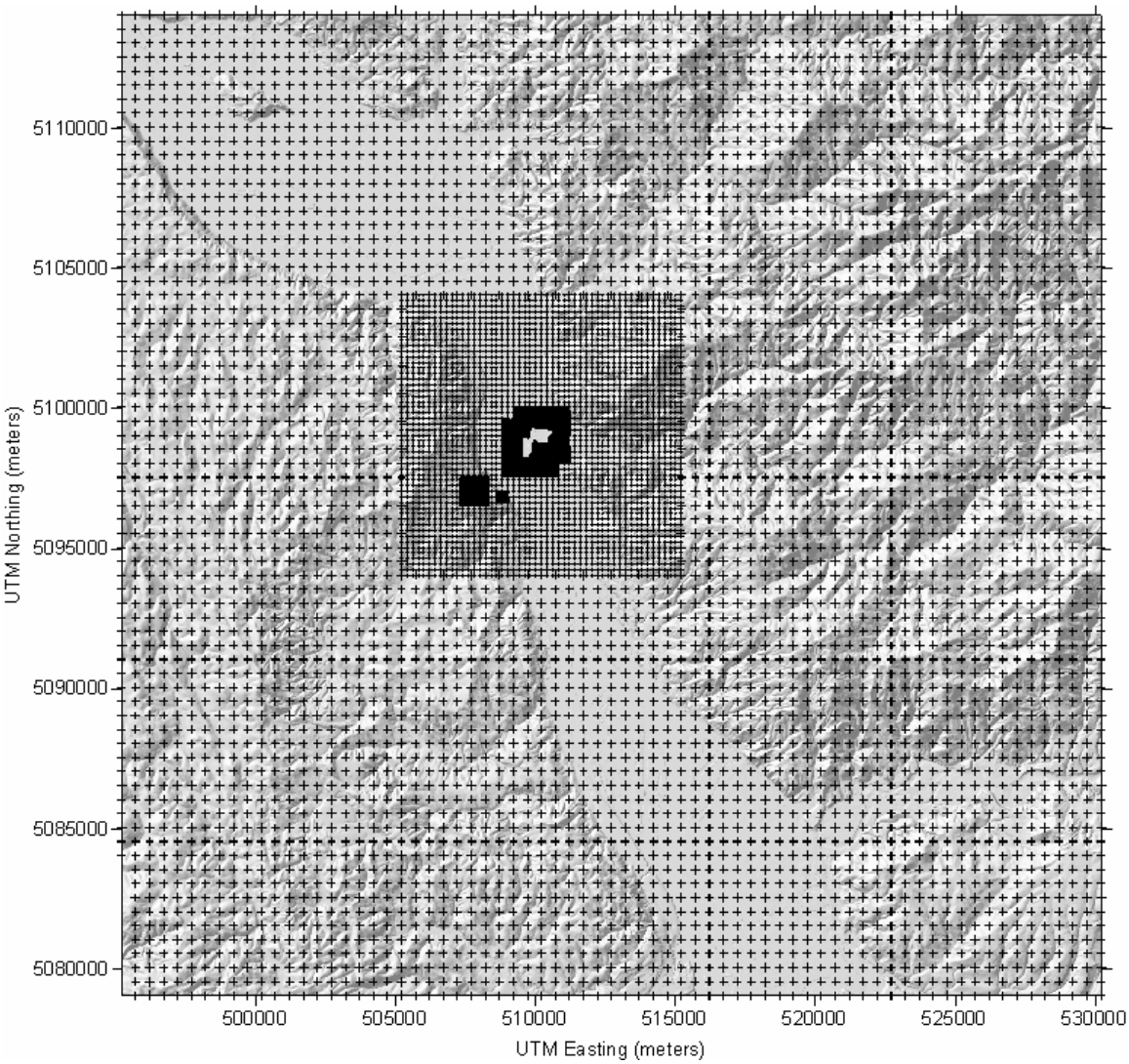


Figure 5.1-5. Final Receptor Locations With Ship Emissions (Fine and Coarse Receptors Added)

TABLE 5.1-28
MAXIMUM PREDICTED PMEC-ONLY
TOXIC AIR POLLUTANT CONCENTRATIONS

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Pollutant	CAS #	TAP Class	Averaging Period	Maximum Concentration[1]	ASIL[2]	Over the SIL?
Acetaldehyde	75-07-0	A	Annual	0.0000724	0.45	No
Ammonia	7664-41-7	B	24-Hour	4.44	100	No
Arsenic	7440-38-2	A	Annual	0.000139	0.00023	No
Benzene	71-43-2	A	Annual	0.00255	0.12	No
Beryllium	7440-41-7	A	Annual	0.00000712	0.00042	No
1,3-Butadiene	106-99-0	A	Annual	0.00000249	0.0036	No
Cadmium	7440-43-9	A	Annual	0.000256	0.00056	No
Chromium, hexavalent	18540-29-9	A	Annual	0.0000294	0.000083	No
Formaldehyde	50-00-0	A	Annual	0.00156	0.077	No
Hydrogen chloride	7647-01-0	B	24-Hour	0.0235	7	No
Hydrogen fluoride	7664-39-3	B	24-Hour	0.0332	8.7	No
Hydrogen sulfide	7783-06-4	B	24-Hour	0.884	0.9	No
Lead	7439-92-1	A	24-Hour	0.000380	0.5	No
Methyl bromide	74-83-9	B	24-Hour	0.0364	5	No
Methylene chloride	75-09-2	B	Annual	0.0000835	0.56	No
Nickel	7440-02-0	B	Annual	0.000362	0.0021	No
Polyaromatic Hydrocarbons	PAH	B	Annual	0.000000421	0.00048	No
Sulfuric acid and sulfates	7664-93-9 & 14808-79-8	B	24-Hour	0.527	3.3	No
Acetaldehyde	75-07-0	A	Annual	0.0000724	0.45	No

1 Maximum from all normal operating scenarios.

2 ASIL = Acceptable Source Impact Level, from WAC 173-460-150 & 160.

To assess cumulative local air quality impacts, emissions from regional industrial sources were combined in modeling simulations with those attributable to PMEC. The scope of regional industrial source emissions included in the cumulative analysis was determined using a "significant impact area" defined in EPA guidance as the farthest distance from the facility where the predicted concentrations attributable to the PMEC alone exceed a SIL. The significant impact area radius predicted by the dispersion model simulations for 24-hour average PM_{10} was approximately 5.0 km from the site. For SO_2, the significant impact area radii for the 1-, 3-, and 24-hour averages, were 20.4, 18.1, and 4.1 km, respectively.

A PSD emission inventory was developed for use in the cumulative analysis to determine compliance with the short-term PM_{10} and SO_2 ambient air quality standards and PSD increments. The PSD emission inventory included all industrial sources located within a circle centered on the site of the proposed facility and having a radius equal to the significant impact area radius plus 50 km. Sources within that circle were then screened using air quality modeling to determine which contribute significantly (i.e., exceed the SILs) at receptors where emissions attributable to the proposed facility also contribute significantly.

EPA guidance stipulates that the impact area for a pollutant requiring cumulative analyses for multiple averaging periods be defined by the largest impact area for that pollutant, and in the case of SO_2, the 1-hour average radius was the largest of the three averaging periods (20.4 km). Although an impact area radius is generally defined for each pollutant, for simplicity, this most distant receptor was used to define the area used to identify regional industrial sources for possible inclusion in the PSD emission inventory for both PM_{10} and SO_2.

5.1.3.8.1 PSD Emission Inventory

Source data for regional industrial sources were obtained from Ecology and the Oregon Department of Ecology (ODEQ), and source elevations were determined using USGS DEM data similar to that used to determine receptor and PMEC source elevations as described in Section 5.1.3.3. Based on the impact area defined by modeling the PMEC, all industrial sources in the databases provided by Ecology and ODEQ within 70.4 km (the 20.4 km maximum significant impact area plus 50 km) were included in the screening analysis. The regional source screening analysis utilized the same methodology applied to evaluate PMEC sources to predict ambient concentrations attributable to nearly 1,000 regional emission units.

The subset of facilities identified by the screening process to significantly affect PM_{10} and SO_2 concentrations in the PMEC significant impact area is summarized in Table 5.1-29. The databases from which the PSD emission inventory was developed, including locations, emissions, and source parameters, are provided on the compact disc with model input files.

TABLE 5.1-29
REGIONAL INDUSTRIAL SOURCES INCLUDED IN PSD EMISSION INVENTORY

Facility	Location	SO2			PM10
		1-hour	3-hour	24-hour	24-hour
Boise Paper	St. Helens, OR	✓	✓	✓	
Georgia-Pacific	Clatskanie, OR	✓			
Longview Fibre	Longview, WA	✓	✓	✓	✓
Weyerhaeuser	Longview, WA	✓	✓	✓	

The PSD program requires demonstration, though a cumulative modeling analysis, that the PMEC, in combination with regional industrial sources, will not cause or contribute to exceedance of ambient standards or PSD increments. While it is appropriate to include all emissions from sources in the PSD emission inventory for determining compliance with ambient air quality standards, only new emission sources, or the incremental increase in emissions for a modified source, established following the major or minor source baseline date for that region (i.e., sources or emissions said to "consume increment") are included in an analysis to determine compliance with PSD increments. According to Ecology, the minor source baseline for both PM_{10} and SO_2 were set in the Portland-Southwest Washington Intrastate Air Quality Control Region (which includes Cowlitz County) on April 28, 1992. The major source baseline date for both pollutants is January 6, 1975.

Because the research required to identify which sources or emissions at a given facility are increment-consuming is extremely resource-intensive, all emissions from all sources at facilities

included in the PSD emission inventory, regardless of the date they were permitted, were included in both the ambient air quality standard and the PSD increment cumulative analyses. This approach is conservative for the PSD increment analysis in that it most likely includes emissions from sources that do not actually consume increment.

5.1.3.8.2 Results

Modeling simulations were developed that evaluated PMEC sources (all normal operating scenarios) and the four facilities in Table 5.1-29. The modeling methodology was the same as that used to determine ambient impacts attributable to the PMEC alone, with the exception of the receptors included in the analyses. Although the significant impact areas are defined as circular for purposes of determining the inclusion or exclusion of regional sources in the initial PSD emission inventory, ambient air quality standard and PSD increment compliance need only be evaluated at receptors where the PMEC is predicted to have a significant impact (i.e., exceeds the SIL). As a result, two sets of receptors were defined for the cumulative analyses, one each for SO_2 and PM_{10}, each comprised of all receptors predicted by the PMEC-only analysis to exceed the SILs for that pollutant. The maximum predicted concentrations from these cumulative analyses are shown in Table 5.1-30.

TABLE 5.1-30
MAXIMUM PREDICTED CUMULATIVE ANALYSIS
CRITERIA POLLUTANT CONCENTRATIONS

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Pollutant	Averaging Period	PMEC and Regional Industrial Sources[1]	PSD Increment	Over PSD Increment	Background	Total[2]	AAQS[3]	Over AAQS?
PM_{10}	24-Hour	8.14	30	No	58.0	66.1	150	No
SO_2	1-Hour	691	None	NA	136	828	1,050	No
	3-Hour	171	512	No	96.8	268	1,300	No
	24-Hour	11.3	91	No	44.5	55.8	262	No

1 Maximum from all normal operating scenarios.

2 Sum of the maximum predicted concentration attributable to the PMEC and regional industrial sources contributing significantly in the PMEC impact areas, and the background concentration.

3 AAQS = Ambient Air Quality Standard. The most stringent standard from among NAAQS/WAAQS/OAAQS.

To demonstrate compliance with ambient air quality standards, it is typical to include a background value. Addition of the background concentrations to a cumulative analysis undoubtedly double-counts emissions from some sources, since some of the modeled sources may have contributed to the monitored concentrations from which the background concentrations are derived. As shown in that table, the maximum concentrations predicted by the cumulative analyses indicate that the PMEC will not contribute to or cause exceedance of either the ambient air quality standards or the PSD increments established for 24-hour average PM_{10} and 1-, 3-, and 24-hour average SO_2.

5.1.3.9 Startup Analysis

To demonstrate that ambient air quality standards will not be exceeded during startup, the short-term startup scenario emission rates described in Section 5.1.2.3 were included in the modeling simulations. AERMOD was applied using the methodology developed for the normal operating scenario simulations. Table 5.1-31 presents a summary of the results of the startup simulations, and indicates that none of the short-term ambient standards would be exceeded during startup. Startup emission rates (where they are expected to exceed normal short-term operating emissions rates) are accounted for in the normal annual operating scenarios.

TABLE 5.1-31
MAXIMUM PREDICTED STARTUP ANALYSIS
CRITERIA POLLUTANT CONCENTRATIONS

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Pollutant	Averaging Period	PMEC Startup[1]	Background	Total[2]	AAQS[3]	Over AAQS?
CO	1-Hour	10,000	7,780	17,780	40,000	No
	8-Hour	1,850	5,720	7,570	10,000	No
PM_{10}	24-Hour	16.6	58.0	74.6	150	No
SO_2	1-Hour	379	136	515	1,050	No
	3-Hour	169	96.8	265	1,300	No
	24-Hour	15.7	44.5	60.2	262	No

1 Maximum from all startup scenarios.

2 Sum of the maximum predicted concentration attributable to the PMEC during startup and the background concentration.

3 AAQS = Ambient Air Quality Standard. The most stringent standard from among NAAQS/WAAQS/OAAQS.

5.1.3.10 Upset Scenarios

There is no regulatory requirement to demonstrate that emissions associated with upset or malfunction situations at a proposed facility do not exceed ambient standards. Indeed it is difficult, if not impossible, to predict all possible upset conditions and calculate emission rates for those scenarios. Nevertheless, two plausible upset scenarios were developed (transmission failure and gasification failure) and are described in Section 5.1.2.4. The proposed facility would operate under upset conditions only as long as needed to safely stabilize and transition to a normal operating or standby status. Although these scenarios do not represent desirable operating conditions, upsets are inevitable, and an investigation of the ambient air quality impacts of emissions from upset conditions is of interest.

Modeling simulations using the methodology developed for normal PMEC operation scenarios were developed to predict ambient concentrations. The results of these analyses are summarized in Table 5.1-32. As shown in that table, all maximum predicted concentrations plus background are less than the applicable ambient air quality standards, indicating that the PMEC would not be expected to cause or contribute to exceedance of any ambient standards when transitioning from an upset condition to a normal operating condition.

TABLE 5.1-32
MAXIMUM PREDICTED UPSET ANALYSIS
CRITERIA POLLUTANT CONCENTRATIONS

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Pollutant	Averaging Period	Upset Scenario[1]		Background	Scenario Total[2]		AAQS[3]	Over AAQS?	
		1	2		1	2		1	2
CO	1-Hour	552	1,097	7,780	8,336	8,881	40,000	No	No
	8-Hour	123	246	5,724	5,847	5,969	10,000	No	No
PM_{10}	24-Hour	6.42	3.17	58.0	64	61	150	No	No
SO_2	1-Hour	116	57	136	252	193	1,050	No	No
	3-Hour	53	24	97.	150	121	1,300	No	No
	24-Hour	5.89	4.61	44.5	50	49	262	No	No

1 Maximum predicted concentration from all normal operating scenarios. Scenario 1 = gasifier upset; Scenario 2 = transmission upset.

2 Sum of the maximum predicted concentrations attributable to the PMEC and regional industrial sources contributing significantly in the PMEC impact areas, and the background concentration.

3 AAQS = Ambient Air Quality Standard. The most stringent standard from among NAAQS/WAAQS/OAAQS.

5.1.3.11 Portland Vancouver Ozone Maintenance Area

Oregon Department of Environmental Quality (ODEQ) retained Washington State University (WSU) to conduct an air quality modeling study evaluating the effects of lower Columbia River industrial emissions on ozone formation in the Portland/Vancouver region.[8] The modeling simulated a July ozone episode in 2015 and considered two future pollutant emission scenarios. One scenario included emissions from potential future industrial growth in the lower Columbia River (similar to the anticipated PMEC emissions). The second scenario did not include any projected future emissions from industries in the lower Columbia River.

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

5.1.4 REGIONAL AIR QUALITY IMPACT ASSESSMENT

PSD regulations require additional impact analyses to assess the influence of the PMEC on Air Quality Related Values (AQRV) in National Parks and Wilderness Areas (Class I areas). The AQRVs of concern in Class I areas include visibility, soil, flora, fauna and aquatic resources. The additional impact section also provides a qualitative discussion of growth associated with the facility and construction impacts.

[8] Summary provided in an email from Svetlana Lazarev of ODEQ to Eric Hansen of Geomatrix Consultants. August 9, 2006.

5.1.4.1 Assessment of Air Quality Related Values for Class I Areas

The locations of the Class I areas in relation to the PMEC site are shown in Figure 5.1-6 and Figure 5.1-7. For projects subject to PSD review, an AQRV analysis is required for Federal Class I areas within 100 km of the site. In the Pacific Northwest, the Federal Land Managers (FLMs) and state agencies typically request the model domain be extended to include additional Class I areas within 200 km.

As shown in Table 5.1-33, the Mt. Adams Wilderness Area is located 95 km east of the PMEC site and is the closest Class I area. An AQRV analysis is required for Mt. Adams Wilderness Area, and seven other Class I areas which are within the 200 km expanded range recommended by the FLMs. The Glacier Peak and Three Sisters Wilderness Areas, which are just outside 200 km from the site, have also been included. Although it is not a Class I area, Ecology and the FLMs requested that the Columbia River Gorge National Scenic Area (CRGNSA) be included in AQRV analyses for informational purposes.

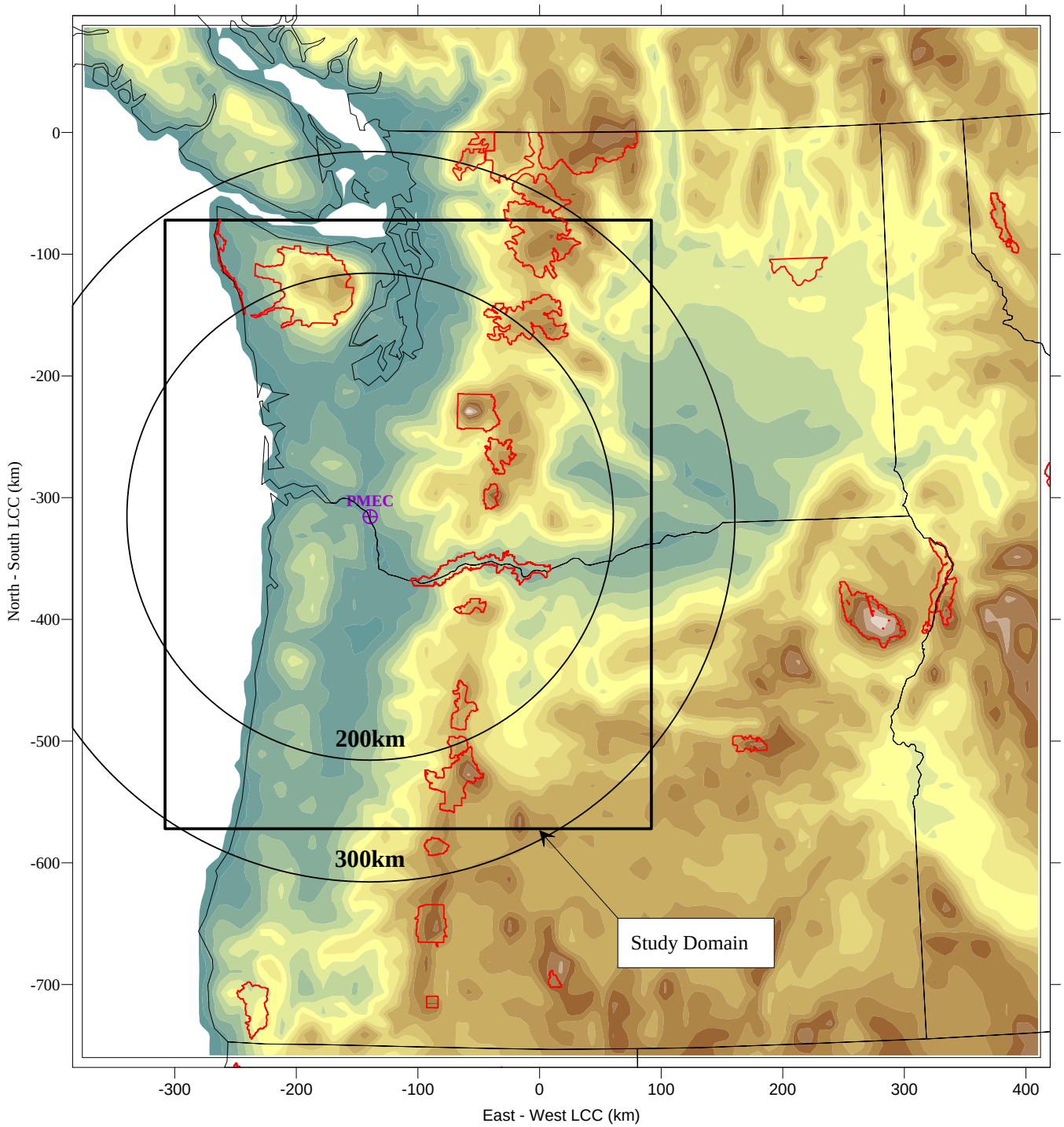
The AQRVs of concern include visibility, soil, flora, fauna, and aquatic resources. Potential impacts to these AQRVs are characterized based on predictions of total nitrogen and/or sulfur deposition flux, change in light extinction, and pollutant concentrations. Pollutant concentration predictions are also used to assess Class I area increment consumption for pollutants subject to PSD review.

5.1.4.1.1 Model Selection

The USEPA's *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) 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.

The CALPUFF modeling system is in a continual process of being upgraded by the model authors. For the simulations in the current AQRV modeling effort, the most recent "beta" release (Version: 6.112, Level: 060412) of CALPUFF was used. This version of the modeling system is being used by Pacific Northwest states and USEPA Region 10 for regional haze simulations associated with determinations for Best Available Retrofit Technology (BART) eligible sources.[9]

[9] Idaho DEQ, 2006. Modeling Protocol for Washington, Oregon, and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulations. Obtained from http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_BART_modeling_protocol.pdf.

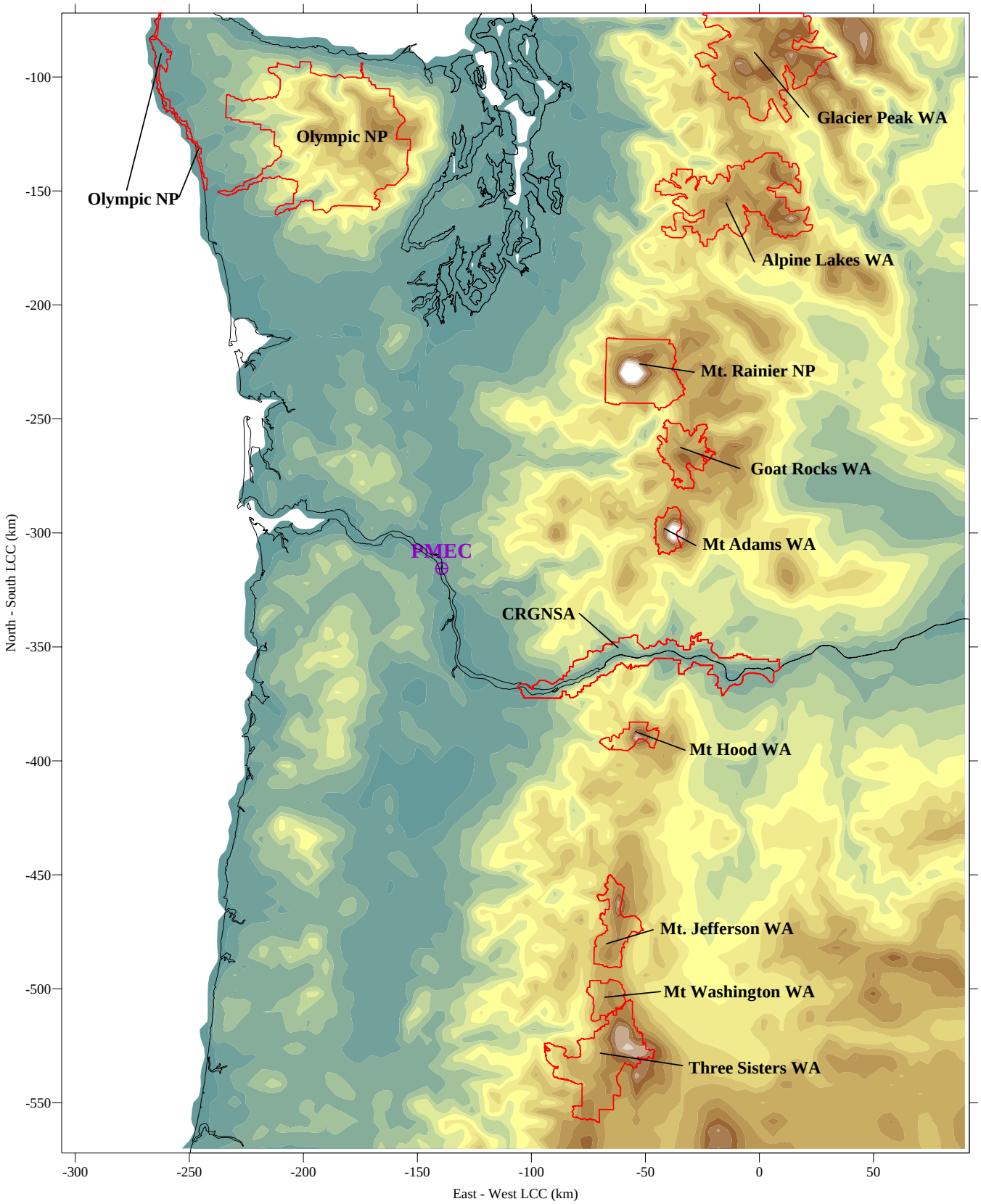


GEOMATRIX

CALPUFF DOMAIN WITH RESPECT TO UW MM5 4KM DOMAIN
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-6



GEOMATRIX

CALPUFF DOMAIN, 4KM TERRAIN, CLASS I AREAS AND CRGNSA
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-7

TABLE 5.1-33
CLASS I AREA DISTANCES FROM PROPOSED PMEC SITE

Distances in kilometers (km)

Class I and Other Areas of Interest	Distance
Alpine Lakes Wilderness	176
Glacier Peak Wilderness	240
Goat Rocks Wilderness	108
Mt. Adams Wilderness	95
Mt. Hood Wilderness	102
Mt. Jefferson Wilderness	153
Mt. Rainier National Park	103
Mt. Washington Wilderness	192
Olympic National Park	160
Three Sisters Wilderness	206
Columbia River Gorge Area [1]	62

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

5.1.4.1.2 CALPUFF Modeling Domain

The modeling domain for the CALPUFF simulations is shown in Figure 5.1-6 and Figure 5.1-7. The 400 km-by-500 km domain is large enough to include the Class I areas of interest with some allowance for complex flows that might cause recirculation of the PMEC plumes within western Washington and Oregon. 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.

5.1.4.1.3 CALPUFF Modeling Procedures

The CALPUFF modeling procedures follow the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM)[10] and the Federal Land Managers Air Quality Related Values Workgroup (FLAG), outlined in the FLAG Phase I Report (December, 2000).[11] USEPA endorsed these procedures in advance in the IWAQM Phase II report (December, 1998). The procedures and defaults recommended by the FLAG Phase I Report were used except where noted in the following discussion. CALPUFF options followed the program defaults for

[10] IWAQM, 1998. Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport and Impacts. USEPA, Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, EPA-454/R-98-019.

[11] FLAG, 2000. Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). Obtained from http://www.fs.fed.us/r6/aq/natarm/NRISFLAG.html.

long-range transport (MREG=1). The puff-splitting option (MPLIT=1) with associated default splitting variables was employed for all predictions at the receptors within the Class I areas and the CRGNSA.[12] The techniques used in the CALPUFF simulations and in the preparation of the meteorological data sets are the same as have been employed in many different PSD applications and previous studies submitted to Ecology.

5.1.4.1.3.1 Emission Rates and PM_{10} Speciation

CALPUFF simulations were performed for three cases using annual emissions, maximum 24-hour emission rates when the turbines are duct-fired, and startup emissions. Emissions from the turbines and duct-burners are based on the higher estimates from the two possible fuels, syngas or natural gas. The emission rates used in the simulations are summarized in Table 5.1-34, Table 5.1-35, and Table 5.1-36 for the 24-hour, annual averaging periods, and startup, respectively. The derivation and assumptions for the criteria pollutant emission rates are in Section 5.1.2.

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 5.1-34 to Table 5.1-36 using USEPA's emission factor document AP-42, guidance from the FLMs for gas-turbines,[13] and the vendor estimates. This information was used to estimate the fractions of sulfate (SO_4), elemental carbon (EC), organic carbon (OC), fine crustal mass (PMF) and coarse crustal mass (PMC) that make up the PM_{10} emitted. This analysis conservatively did not account for any reduction in SO_2 emissions necessary to account for the sulfate assumed in the PM_{10} fraction emitted from any of the PMEC sources. Thus the potential influence of the PMEC sources on AQRVs related to sulfur is "double-counted" to some degree by the simulations.

---

[12] In order to reduce the large runtimes associated with the puff-splitting option, model predictions at the gridded receptors were obtained without puff-splitting. Such predictions were used for the contour plots presented in this report. The more accurate results with puff-splitting were used in the tables and for comparison with AQRV criteria.

[13] 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. In-Stack Condensable Matter Measurements and Issues. J. Air & Waste Manage. Assoc., Vol 50, Feb. 2000, pp 207-218.

TABLE 5.1-34
SPECIATED 24-HOUR EMISSION RATES FOR AQRV ANALYSIS

Emission rates in pounds per hour (lb/hr)

Source	SO2	NOX	PM10	(NH4)2 -SO4	SO4	EC	OC	PMF	PMC
CTG No. 1 [1]	25.80	33.92	27.61	3.00	2.18	6.90	17.71	0.00	0.00
CTG No. 2 [1]	25.80	33.92	27.61	3.00	2.18	6.90	17.71	0.00	0.00
Tank Vent Oxidizer [1]	3.91	19.50	0.65	0.65	0.47	0.00	0.00	0.00	0.00
Auxiliary Boiler [1]	0.32	4.68	0.65	0.20	0.15	0.16	0.29	0.00	0.00
Flare [1]	0.01	0.14	0.02	0.00	0.00	0.00	0.01	0.00	0.00
Emerg. Diesel Generator [4]	0.05	1.17	0.04	0.00	0.00	0.03	0.00	0.00	0.00
Emerg. Diesel Fire Pump [4]	0.01	0.21	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Power Block Cool Towers[2]	0.00	0.00	1.76	0.00	0.00	0.00	0.00	1.76	0.00
Dome Ventilation [3]	0.00	0.00	0.15	0.00	0.00	0.00	0.00	0.05	0.10
Gasif/ASU Cool Towers [2]	0.00	0.00	0.97	0.00	0.00	0.00	0.00	0.97	0.00
Fugitive Train Unloading [3]	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Fugitive Ship Unloading [3]	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.11	0.24
Fugitive Dome Transfer [3]	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Ship Exhaust [4]	5.31	11.97	0.61	0.07	0.05	0.54	0.00	0.00	0.00

1) Preliminary engineering estimates for ammonium sulfate is 3 lb/hr for each turbine. For the Tank Vent Oxidizer and Auxiliary Boiler, a 30 percent conversion of SO_2 to ammonium sulfate was assumed. Five percent conversion was assumed for the Flare. Based on NPS recommendations for gas-fired turbines, 30% of the PM_{10} is assumed to be filterable and consist of EC. The condensable fraction is assumed to consist of ammonium sulfate from conversion of SO_2 and the remainder is OC.

2) All PM_{10} was assumed to consist of fine crustal mass.

3) Size fractions for materials handling are based on Chapter 13 of USEPA's emission factor document AP-42 (Table 13.2.4.3).

4) PM_{10} condensable fraction in USEPA's emission factor document AP-42 Chapter 3.4.2 is assumed to be ammonium sulfate and the remainder EC.

TABLE 5.1-35
SPECIATED ANNUAL EMISSION RATES FOR AQRV ANALYSIS

Emission rates in tons per year (TPY)

Source	SO2	NOX	PM10	(NH4)2 -SO4	SO4	EC	OC	PMF	PMC
CTG No. 1 [1]	75.34	157.26	120.93	13.14	9.56	30.23	77.56	0.00	0.00
CTG No. 2 [1]	75.34	157.26	120.93	13.14	9.56	30.23	77.56	0.00	0.00
Tank Vent Oxidizer [1]	16.53	19.71	0.66	0.66	0.48	0.00	0.00	0.00	0.00
Auxiliary Boiler [1]	0.50	5.12	0.71	0.31	0.22	0.18	0.23	0.00	0.00
Flare [1]	4.08	14.06	1.61	0.42	0.31	0.40	0.78	0.00	0.00
Emerg. Diesel Generator [4]	0.05	1.41	0.04	0.01	0.00	0.04	0.00	0.00	0.00
Emerg. Diesel Fire Pump [4]	0.01	0.26	0.01	0.00	0.00	0.01	0.00	0.00	0.00
Power Block Cool Towers[2]	0.00	0.00	7.72	0.00	0.00	0.00	0.00	7.72	0.00
Dome Ventilation [3]	0.00	0.00	0.64	0.00	0.00	0.00	0.00	0.20	0.44
Gasif/ASU Cool Towers [2]	0.00	0.00	3.89	0.00	0.00	0.00	0.00	3.89	0.00
Fugitive Train Unloading [3]	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.01	0.02
Fugitive Ship Unloading [3]	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.07	0.15
Fugitive Dome Transfer [3]	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.01	0.02
Ship Exhaust [4]	3.32	7.50	0.38	0.05	0.03	0.34	0.00	0.00	0.00

1) Preliminary engineering estimates for ammonium sulfate is 3 lb/hr for each turbine. For the Tank Vent Oxidizer and Auxiliary Boiler, a 30 percent conversion of SO_2 to ammonium sulfate was assumed. Five percent conversion was assumed for the Flare. Based on NPS recommendations for gas-fired turbines, 30% of the PM_{10} is assumed to be filterable and consist of EC. The condensable fraction is assumed to consist of ammonium sulfate from conversion of SO_2 and the remainder is OC.

2) All PM10 was assumed to consist of fine crustal mass.

3) Size fractions for materials handling are based on Chapter 13 of USEPA's emission factor document AP-42 (Table 13.2.4.3).

4) PM10 condensable fraction in USEPA's emission factor document AP-42 Chapter 3.4.2 is assumed to be ammonium sulfate and the remainder EC.

TABLE 5.1-36
SPECIATED 24-HOUR STARTUP EMISSION RATES FOR AQRV ANALYSIS

Emission rates in pounds per hour (lb/hr)

Source	SO2	NOX	PM10	(NH4)2 -SO4	SO4	EC	OC	PMF	PMC
CTG No. 1 [1]	25.80	55.69	27.61	3.00	2.18	6.90	17.71	0.00	0.00
CTG No. 2 [1]	25.80	55.69	27.61	3.00	2.18	6.90	17.71	0.00	0.00
Tank Vent Oxidizer [1]	3.91	19.50	0.65	0.65	0.47	0.00	0.00	0.00	0.00
Auxiliary Boiler [1]	0.32	4.68	0.65	0.20	0.15	0.16	0.29	0.00	0.00
Flare [1]	18.46	58.47	6.68	1.90	1.38	1.67	3.11	0.00	0.00
Emerg. Diesel Generator [4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emerg. Diesel Fire Pump [4]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Power Block Cool Towers[2]	0.00	0.00	1.76	0.00	0.00	0.00	0.00	1.76	0.00
Dome Ventilation [3]	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Gasif/ASU Cool Towers [2]	0.00	0.00	1.03	0.00	0.00	0.00	0.00	1.03	0.00
Fugitive Train Unloading [3]	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Fugitive Ship Unloading [3]	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.11	0.24
Fugitive Dome Transfer [3]	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.03	0.06
Ship Exhaust [4]	5.31	11.97	0.61	0.07	0.05	0.54	0.00	0.00	0.00

1) Preliminary engineering estimates for ammonium sulfate is 3 lb/hr for each turbine. For the Tank Vent Oxidizer and Auxiliary Boiler, a 30 percent conversion of SO_2 to ammonium sulfate was assumed. Five percent conversion was assumed for the Flare. Based on NPS recommendations for gas-fired turbines, 30% of the PM_{10} is assumed to be filterable and consist of EC. The condensable fraction is assumed to consist of ammonium sulfate from conversion of SO_2 and the remainder is OC.

2) All PM_{10} was assumed to consist of fine crustal mass.

3) Size fractions for materials handling are based on Chapter 13 of USEPA's emission factor document AP-42 (Table 13.2.4.3).

4) PM_{10} condensable fraction in USEPA's emission factor document AP-42 Chapter 3.4.2 is assumed to be ammonium sulfate and the remainder EC.

The release parameters used in the CALPUFF simulations are shown in Table 5.1-37. The stack parameters for the turbines are based on combustion and duct-burning with syngas. Emissions from the two combustion turbine stacks were combined and simulated using the stack parameters of a single turbine stack. The Tank Vent Oxidizer, Auxiliary Boiler, and Flare were each simulated as individual point sources. Stack parameters for the Flare are based on the startup conditions for the annual and startup cases. For the 24-hour emissions case it was assumed the Flare was operating in stand-by mode (pilot only). In order for the simulations to finish in a reasonable time, several of the smaller emission sources were combined together. Emissions from these smaller remaining sources were combined and simulated as a non-buoyant volume source. The location of the volume source was calculated from the average of the individual source coordinates. The volume source release height was calculated in a similar fashion. The initial horizontal and vertical volume source dimensions were calculated from the associated standard deviations of the individual coordinates.

5.1.4.1.3.2 Chemical Transformations

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.

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 based on one of the few monitoring studies available where ammonia data were collected. Our experience suggests the use of this conservative concentration ensures the conversion of NO_X to ammonium nitrate is not limited by a lack of ammonia.

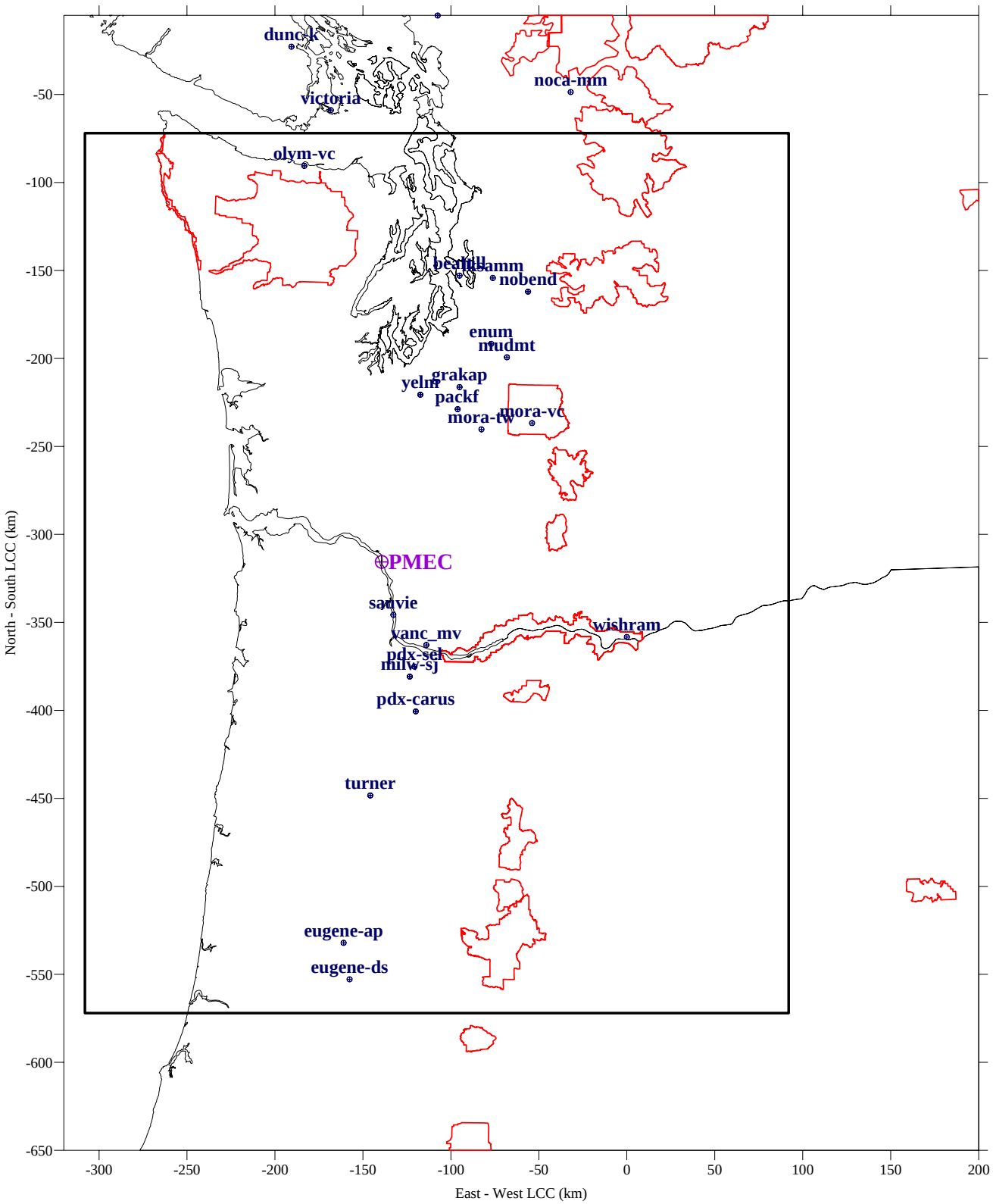
Reaction rates in the CALPUFF chemistry algorithms are also influenced by background ozone concentrations. Ozone data were obtained, collected concurrent with the modeled period at National Park Service (NPS) stations within the CALPUFF study area (Marblemount near North Cascades National Park, Tahoma Woods near Rainier National Park, and the Visitor Center near Olympic National Park). Additional data were also collected from stations both inside and outside the study area from Ecology, the British Columbia Ministry of Water, Land, and Air Protection (MWLAP), and the ODEQ. The ozone station locations are shown in Figure 5.1-8. The NPS and MWLAP stations operate all year unlike most of Ecology's and ODEQ's ozone stations, which only operate during the "ozone" season. For periods of missing data outside the ozone season, a conservative background ozone concentration of 40 ppb was used to prevent a limited number of observations from having undue influence throughout the modeling domain.

TABLE 5.1-37
CALPUFF RELEASE PARAMETERS FOR AQRV ANALYSIS

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

Notes:

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



GEOMATRIX

OZONE MONITORING STATIONS WITHIN AND NEAR CALPUFF DOMAIN
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-8

5.1.4.1.3.3 Meteorological Data

Meteorological data sets were obtained from the University of Washington (UW) based on numerical simulations of Pacific Northwest weather with the Penn State and National Center of Atmospheric Research Mesoscale Model (MM5). The AQRV analysis used three calendar years of hourly MM5 output data from 2003 through 2005. The 2003 and 2004 UW MM5 simulations are based on a 4-km mesh size and over 30 vertical levels. The UW's 12-km mesh size MM5 simulations for 2005 were processed and these data were used to construct the third year of meteorological data. A third year of processed 4-km mesh size MM5 solutions was not available for this analysis. The study domain is a subset of both the UW 4-km mesh and 12-km mesh size MM5 domains as shown in Figure 5.1-6.

CALMET, 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. CALMET default options were used except where noted in Table 5.1-38. Major features of the CALMET application and input data preparation are as follows:

- The 4-km mesh size MM5 winds for January 2003 through December 2004, and 12-km mesh size MM5 winds for 2005 were used to initialize the three-dimensional wind field predictions. The data recovery for the MM5 archive was greater than 99 percent. Periods of missing data were filled by interpolation and by repeating the previous day for longer periods.
- CALMET objective procedures were used with local terrain and land use data to adjust the MM5 12-km wind fields down to a 4-km mesh size grid. Since the CALMET terrain is less smooth than needed by MM5 for the same mesh size, these procedures also adjust the 4-km mesh size MM5 winds to some extent. The pressure-based vertical level MM5 fields were reduced and layer-averaged resulting in 10 vertical levels from the surface to 4,000 m.
- The "no observations" option (NoObs = 1) in CALMET was used to extract hourly precipitation and upper air temperature lapse rates from the MM5 data set. Other switches were set to use the MM5 surface temperature and relative humidity rather than using observations whose locations are usually in the lowland areas of the modeling domain.
- Local observed wind speed and wind direction were not used in the preparation of the wind fields. The wind fields used in the AQRV analysis depend solely on the MM5 winds and the objective procedure applied by CALMET. This was accomplished by selecting the non-default interpolation options shown in Table 5.1-38.

TABLE 5.1-38
NON DEFAULT CALMET OPTIONS

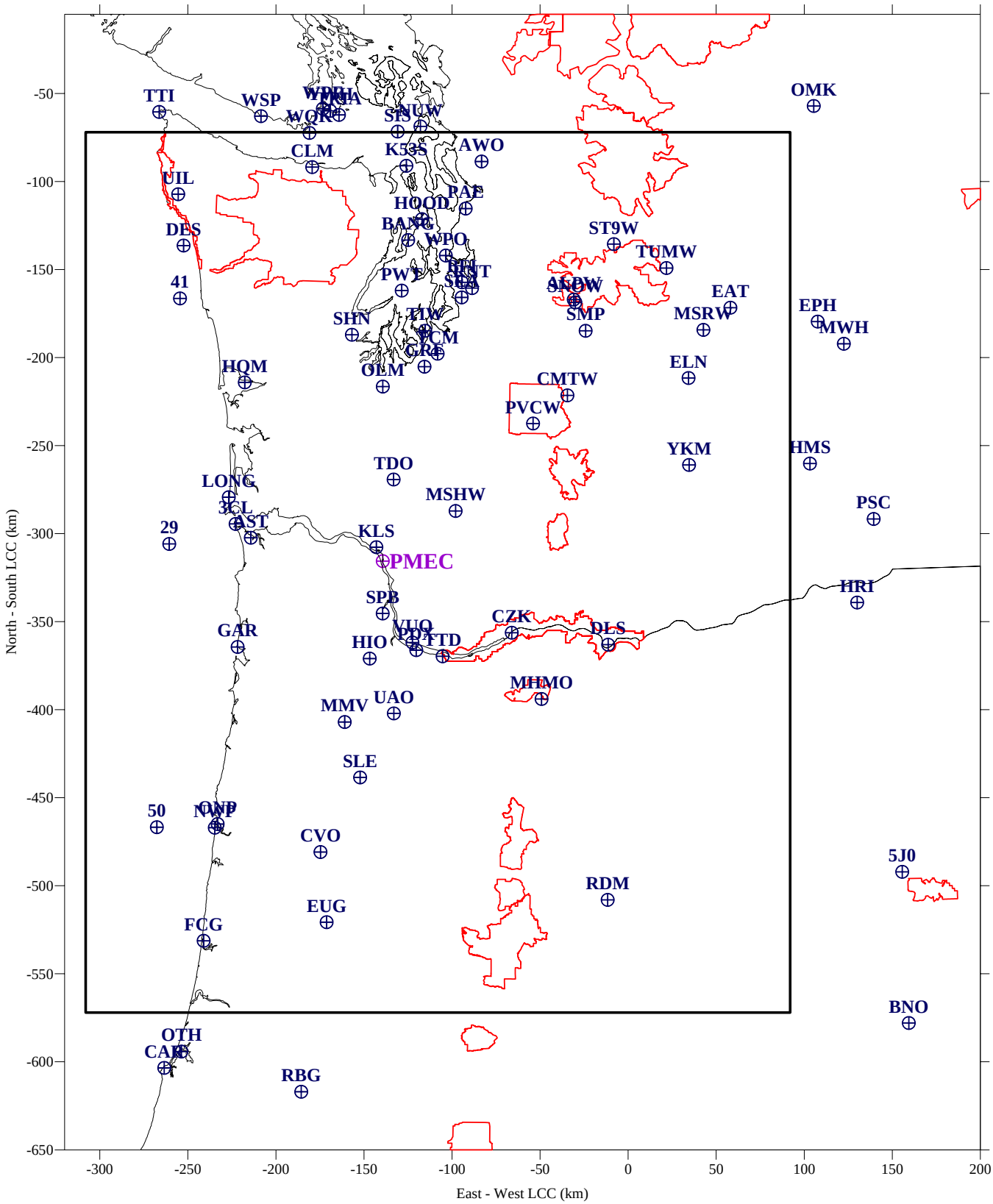
CALMET Variable	Selected Value	Rationale
noobs	1	Use MM5 upper air data.
npsta	-1	Use MM5 precipitation data.
iextrp	-1	Since we would use MM5 for upper levels, do not extrapolate observed surface winds aloft. (Note, the similarity profile method (iextrp = -4) also is not applicable in complex terrain.)
rmin2	-1	Not used, since iextrp=-1 and noobs=1
iprog	14	Use MM5 as a first guess but allow CALMET to adjust for terrain. Note CALMET terrain for the same mesh size is more resolved than the MM5 terrain, because the later is smoothed to reduce the noise in the numerical solutions.
terrad	12 for 12km MM5 mesh; 4 for 4km MM5 mesh	Allow CALMET to adjust winds to local terrain for about 1 MM5 grid point.
r1 & r2	1.e-6	Do not allow CALMET to use the observed winds. We would use the MM5 solutions and CALMET terrain adjustment procedures. We could also do this with noobs=2, but we do not want the CALMET algorithm for cloud cover.
nsmth	1-4 for 12km MM5 mesh; 1-2 for 4km MM5 mesh	Do not smooth the winds too much and smooth the 4km MM5 based winds less than the 12km MM5 winds.
niter	50 for 12km MM5 mesh; 2 for 4km MM5 mesh	There is divergence in complex terrain that should be reflected in the 4km MM5 solutions. Do not get rid of all this divergence, but also do not let CALMET introduce divergence in the 12km MM5 solutions.
irhprog	1	Use MM5 relative humidity
itprog	2	Use MM5 surface temperatures
icoare	0	Original OCD delta T method for over water. Not used as indicated below.
jwat1 & jwat2	100	Forces CALMET's to treat the boundary layer over water the same as over land.
sigmap	12 for 12km MM5 mesh; 4 for 4km MM5 mesh	A larger default radius of interpolation results in "bull-eyes" of precipitation due to the CALMET weighting scheme applied to the MM5 precipitation predictions. Set the radius to the MM5 mesh size.

- Surface observations with and near the study domain were used to provide hourly cloud cover and ceiling height data. The source of surface meteorological data was the UW's Pacific Northwest observation archive.[14] The stations selected from the archive are shown in Figure 5.1-9. These surface stations include all the METAR stations near the domain, plus some other Coast Guard and SNOTEL stations in areas where METAR data are sparse. Note, only the stations with cloud cover and ceiling height actually influence the CALMET runs using the options in Table 5.1-38. The other stations were included in case it was necessary to change the CALMET options or compare MM5/CALMET winds to observed winds at these locations.
- CALMET options were selected to use less smoothing and less divergence reduction for the simulations based on the 4-km mesh size MM5 data. Although the 4-km terrain in MM5 is smoothed and less representative than the 4-km terrain used by CALMET, the CALMET terrain adjustment algorithms should have less influence when using the 4-km MM5 data than when using the 12-km MM5 data. Also divergence is expected in complex terrain and should not necessarily be removed by CALMET when predicted by MM5.
- The new over water dispersion and boundary layer options included in CALPUFF version 6 were not selected for the simulations. Such options require the MM5 data be reprocessed from the raw UW archives so additional MM5 variables can be passed through to CALMET. Such data are not yet available for this analysis. Options were selected such that the treatment of over water conditions used the same routines as over land, except the variables characterizing the surface are appropriate for the ocean. The assumptions result in a near neutral boundary layer over the ocean.

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. Wind vector plots were also prepared for four days (one in each year and at least one in each season), three times on each day (4am, 10am, and 4pm), and three vertical levels for each day and time. These vector plots were provided to Ecology[15] and are included in the computer files supporting this application.

[14] The UW archive can be examined at http://www.atmos.washington.edu/data. The archive contains Pacific Northwest observations from 1996 to present.

[15] "Analysis of calmet winds for ENW-IGCC at Port of Kalama". Email from Ken Richmond, Geomatrix to Clint Bowman, Ecology on July 7, 2006. The files were supplied via the Geomatrix ftp site.



GEOMATRIX

SURFACE METEOROLOGICAL SITES WITHIN OR NEAR CALPUFF DOMAIN
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-9

Wind roses of surface winds were prepared for meteorological stations of interest and predictions at nearby CALMET grid points to assess the agreement between the simulated and observed winds. CALMET and observed winds at Astoria, Salem, Troutdale, The Dalles, Kelso, and Portland were used for these comparisons. Although for different periods, a wind rose was constructed for the CALMET winds predicted at the PMEC site during 2003-2005 to compare with observed annual winds during 1995. The 1995 Port of Kalama meteorological data were used as the basis for the local impact assessment discussed in Section 5.1.3. These wind roses were also provided to Ecology for review of the CALMET data sets.

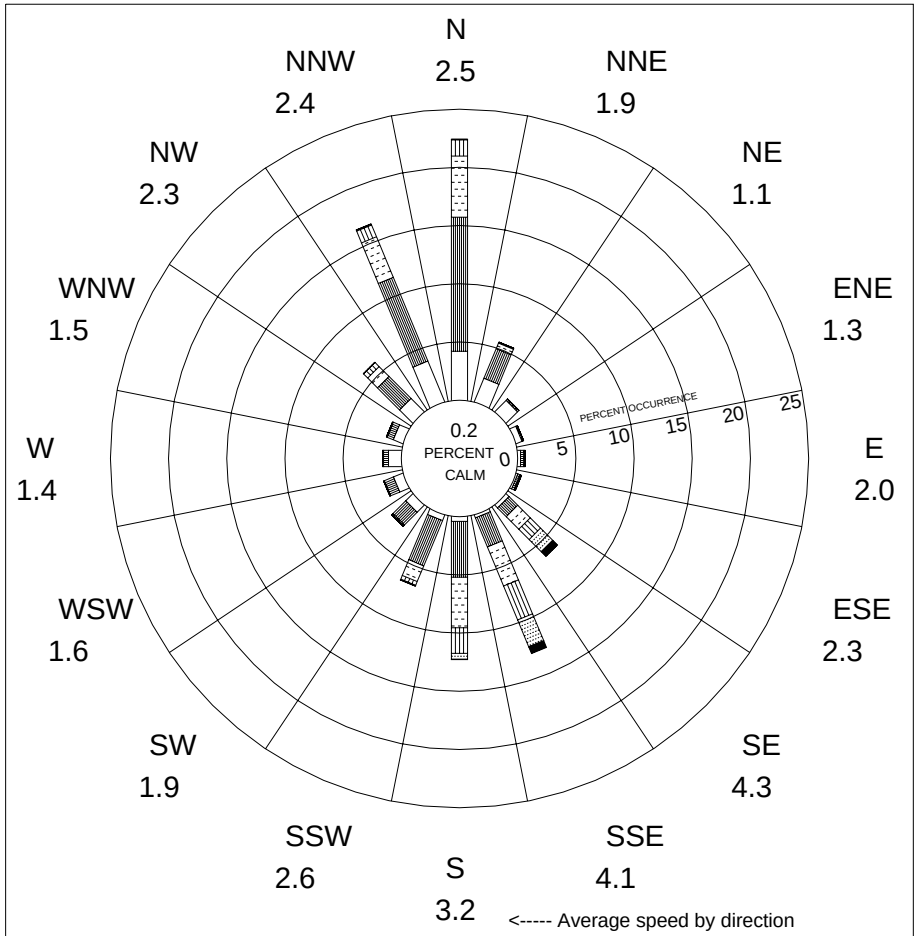
Figure 5.1-10 compares surface winds predicted by CALMET during 2003-2005 to observed winds collected at the Port of Kalama during 1995. The annual average predicted and observed wind speeds were 3.3 m/s and 2.7 m/s, respectively. Although these are different periods, the annual wind roses should be similar and show the same general terrain channeling. The CALMET/MM5 predicted winds capture the main features of the observed annual surface winds near the site, although the predicted prevailing winds are not quite as oriented along a north-to-south axis. The smoothed 4-km mesh size CALMET terrain is less severe and the winds are not channeled to the extent observed at the Port of Kalama. Local winds are expected to be more severely channeled near the surface. Plumes for the important sources at PMEC are usually several hundred meters aloft where the CALMET/MM5 winds are thought to be representative of region flow.

5.1.4.1.3.4 Elevation Data and Receptor Network

The CALPUFF dispersion model simulations assessed AQRVs at discrete receptors within each Class I area using the receptor locations provided by the NPS.[16] Receptor elevations at these locations were calculated from the 4-km mesh size terrain using the same methods used by CALMET to develop the wind fields and by CALPUFF to estimate the height of puffs above terrain. Although the receptor elevations provided with the NPS receptors are likely more representative of the actual terrain at the receptor locations, consistency with the meteorology used in the simulations was deemed to be more important than accurately reflecting the terrain heights. The CALPUFF modeling system bases many puff properties on the height above ground, which is calculated using the same terrain grid used by CALMET to alter the winds and produce a mass consistent wind field that reflects the terrain. Because the use of terrain elevations other than those in the model terrain grid introduces potential inconsistencies, elevations in the model terrain grid were used in the predictions.

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.

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

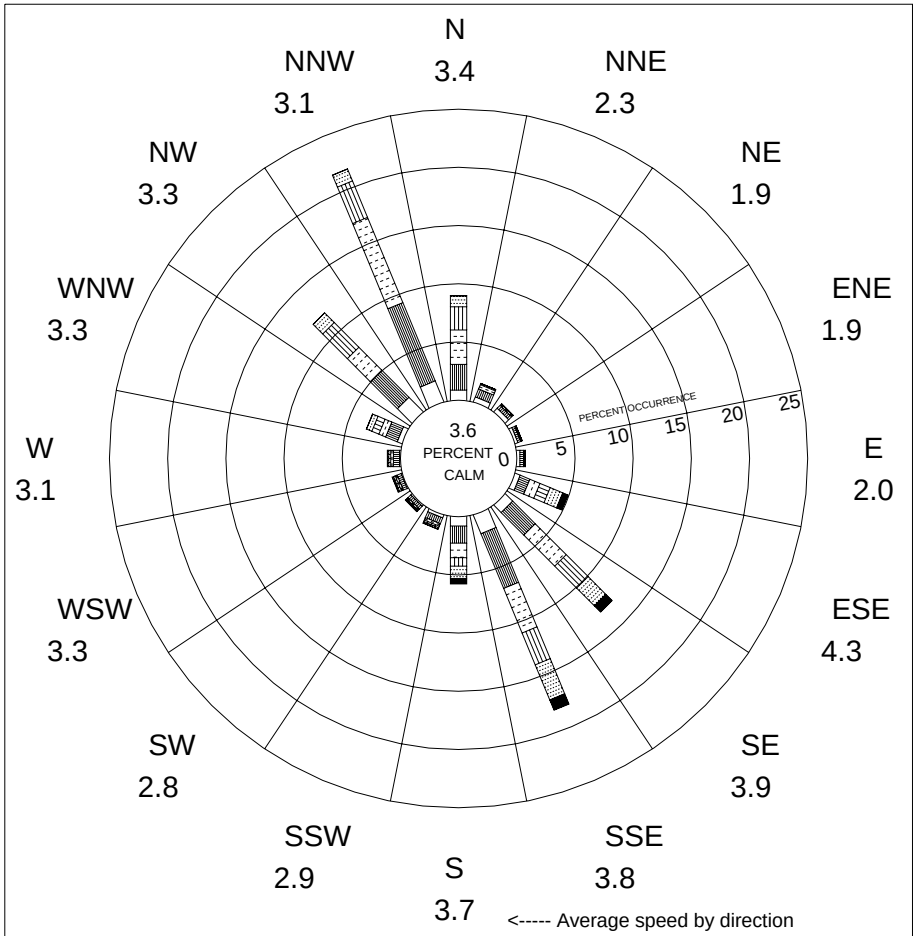


WIND SPEED RANGE

- 0.1 - 1.5 M/S
- 1.5 - 3.0
- 3.0 - 4.0
- 4.0 - 5.0
- 5.0 - 7.0
- > 7.0

Port of Kalama Observed Winds
January 1, 1995 to Decmeber 31, 1995

WIND FREQUENCY DISTRIBUTION



WIND SPEED RANGE

- 0.1 - 1.5 M/S
- 1.5 - 3.0
- 3.0 - 4.0
- 4.0 - 5.0
- 5.0 - 7.0
- > 7.0

Port of Kalama CALMET Grid Point Winds
Jan 1, 2003 - Dec 31, 2005

WIND FREQUENCY DISTRIBUTION

GEOMATRIX

CALMET PREDICTED VS OBSERVED SURFACE WINDS NEAR KALAMA
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-10

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 also based on the CALMET 4-km mesh size terrain.

Land use and terrain data were prepared from the North American 30 second data sets that accompany the CALPUFF modeling system using the tools included in the system. The resulting 4-km mesh size terrain grid was contoured and is shown in Figure 5.1-7. As described above, the same terrain grid used to develop the CALMET wind fields and used internally by CALPUFF was also used to obtain receptor and source base elevations.

5.1.4.1.3.5 AQRV Calculation Procedures

The CALPUFF modeling system was used to predict criteria pollutant concentrations, total deposition fluxes, and light extinction coefficients attributable to PMEC 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} 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 for PMEC emissions to contribute to regional haze was predicted using 24-hour average extinction coefficients as a measure of visibility degradation. The analysis assessed the potential for direct particle emissions and secondary aerosols formed from the gases emitted by the PMEC to reduce visual ranges in Class I areas. The procedure assumes regional visibility degradation is primarily due to light extinction caused by scattering by fine particles including sulfates and nitrates, and by light absorption from soot particles.

In the FLAG Phase I Report, the FLMs recommend that a five percent change in extinction be used to indicate a “just perceptible” change to a landscape. Extinction coefficients were calculated from the CALPUFF output files using the post-processing program CALPOST. CALPOST calculates extinction coefficients from concentrations of aerosols directly emitted, sulfate concentrations, nitrate concentrations, and relative humidity. CALPOST can also summarize expected changes to background extinction as a function of hourly relative humidity at each receptor and assumed background aerosol concentrations.

The general equation applied in CALPOST divides the extinction coefficient into two components as follows:

$$b_{ext} = b_{SN}\, f(RH) + b_{dry} \quad (1)$$

where b_{ext} is the extinction coefficient (inverse megameters or Mm^{-1}), $f(RH)$ is the relative humidity adjustment factor, b_{SN} is the sulfate and nitrate or hygroscopic portion of the extinction coefficient (Mm^{-1}), and b_{dry} is the non-hygroscopic portion of the extinction coefficient (Mm^{-1}). The hygroscopic portions of the extinction budget are calculated from the sulfate and nitrate concentrations predicted by CALPUFF according to:

$$b_{SN} = 3[(NH_4)2SO_4 + NH_4NO_3] \qquad (2)$$

where the sulfate and nitrate concentrations have units of $\mu g/m^3$ and are converted for the change in molecular weight due to the assumed chemical form of the aerosol. In the simulations, relative humidity was limited to 95 percent as recommended in guidance from the Ecology and the USEPA for estimates of background visibility.[17] The portion of the extinction coefficient that does not vary with humidity is calculated from:

$$b_{dry} = 4[OC] + 1[Crustal\ Mass] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray} \qquad (3)$$

where [OC] is the organic carbon portion of the $PM_{2.5}$, [Crustal Mass] is the crustal portion ($PM_{2.5}$ that cannot be classified as organic or elemental carbon) of the $PM_{2.5}$, [Coarse Mass] is the portion of the mass between $PM_{2.5}$ and PM_{10}, [EC] is the elemental carbon (soot) portion of $PM_{2.5}$, and b_{Ray} is extinction due to Rayleigh scattering assumed to be 10 Mm^{-1}. Concentrations in Equation 3 also have units of $\mu g/m^3$.

5.1.4.1.3.6 Baseline AQRV Data

Soils, vegetation and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition. Nitrogen and sulfur deposition occur through both wet and dry processes and both direct emissions and secondary aerosols formed during transport from a source to a Class I area can contribute to total deposition. The FLMs believe that the effects caused by pollutant loading on these AQRVs are nonlinear and they request that model predictions be added to conservative background estimates. The FLMs assess potential effects on a case-by-case basis using cumulative total deposition flux estimates. Nitrogen and sulfur deposition background estimates are summarized in Table 5.1-39.

[17] USEPA, 2003. Guidance of Estimating Natural Visibility Conditions under the Regional Haze Rule. USEPA Office of Air Quality Planning and Standards, Research Triangle Park, NC 27711, EPA-454/B-03-005, September 2003.

TABLE 5.1-39
EXISTING BACKGROUND DEPOSITION IN CLASS I AREAS AND CRGNSA

Deposition fluxes in kilograms per hectare per year (kg/ha/yr)

Class I Area[1]	Total Nitrogen Deposition	Total Sulfur Deposition
Alpine Lakes Wilderness	5.2	7.2
Glacier Peak Wilderness	5.8	8.0
Goat Rocks Wilderness	9.0	11.8
Mt. Adams Wilderness	9.0	10.8
Mt. Hood Wilderness	5.4	8.6
Mt. Jefferson Wilderness	1.8	4.0
Mt. Rainier National Park	2.4	3.1
Mt. Washington Wilderness	2.6	5.0
Olympic National Park	2.0	5.6
Three Sisters Wilderness	3.6	5.6
CRGNSA [2]	10.0	12.0

1 Background deposition fluxes for USDA Forest Service areas were developed using a scientific consensus process from a 1990 workshop. These data are considered to represent a conservative upper limit for these areas – they are not spatially or temporally averaged values. The deposition fluxes are reported in Table 11 of *Guidelines for Evaluating Air Pollution Impacts on Class I Areas in the Pacific Northwest.* USDA Forest Service, General Technical Report PNW-GTR-299, May 1992 (Peterson, J., et al., 1992).

National Park Service data are based on 1995-2000 National Acid Deposition Program annual average deposition values collected at the Hoh Ranger Station (Olympic) and Pack Forest (Mt. Rainier) monitoring sites.

For all areas, total background deposition is conservatively assumed to be double the reported wet deposition flux to account for additional dry and occult (cloud water) deposition processes.

2 The CRGNSA is not a Class I area. Background data for the CRGNSA are from Bob Bachman (USDA Forest Service) in email of July 12, 2001 based on Lichen monitoring data

For background visibility at all Class I areas of interest, the FLAG western U.S. defaults were used for the hygroscopic (0.6 Mm^{-1}), dry (4.5 Mm^{-1}), and Rayleigh (10 Mm^{-1}) scattering portions of the extinction coefficient. These defaults were applied within CALPOST using the following options: MVISBK = 2, BKSO4=0.2, BKSOIL=4.5 and BEXTRAY=10.

The background aerosol concentrations used to characterize background extinction in the CRGNSA are shown in Table 5.1-40. The CRGNSA is not a Class I area and has both regional and industrial sources located within its boundaries. Based on guidance from the USDA Forest Service, background estimates for aerosol concentrations in the CRGNSA were based on the average of observations for the 20 percent days with the lowest reconstructed extinction coefficients. Such aerosol concentrations result in a conservative, but more realistic

characterization of background extinction in the CRGNSA than the FLAG defaults for "natural" background.

TABLE 5.1-40
BACKGROUND AEROSOL CONCENTRATIONS FOR THE CRGNSA

Concentrations are in micrograms per cubic meter ($\mu g/m^3$)

Aerosol Species	Spring	Summer	Autumn	Winter
Ammonium Sulfate	0.553	0.928	0.556	0.319
Ammonium Nitrate	0.231	0.172	0.258	0.244
Fine Crustal Mass (PMF)	0.241	0.295	0.294	0.191
Organics (OC)	0.849	0.856	0.985	0.897
Elemental Carbon (EC)	0.169	0.172	0.220	0.240
Coarse Mass (PMC)	4.835	5.810	3.632	5.114

Note:

[1] Based on the 20 percent days with the best visibility at the Wishram monitoring station from 1993 through 2000. The data were provided by Bob Bachman of the USDA Forest Service in an email to Ken Richmond of Geomatrix on February 26, 2001.

5.1.4.1.4 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. The CALPUFF simulations used the three emission casses presented in Table 5.1-34 to Table 5.1-36, and the source release parameters shown in Table 5.1-37. The resulting CALPUFF output files were post-processed to extract the necessary variables for comparison with the FLM Class I AQRV criteria.

5.1.4.1.4.1 Criteria Pollutant Concentrations

Table 5.1-41 summarizes the predicted maximum criteria pollutant concentrations and compares them to the Class I SILs[18] and the Class I PSD increments. This table was constructed from the results of the maximum 24-hour (excluding startup) and annual emission cases. 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.[19] CALPUFF simulations indicate criteria pollutant concentrations attributable to PMEC are less than the Class I SILs and the increments in all Class I areas and the CRGNSA (Table 5.1-41).

[18] At this point, 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.

[19] Guidelines for Evaluating Air Pollution Impacts on Class I Areas in the Pacific Northwest. USDA Forest Service, General Technical Report PNW-GTR-299, May 1992 (Peterson, J., et al., 1992).

TABLE 5.1-41
PREDICTED CLASS I AREA AND CRGNSA CRITERIA POLLUTANT CONCENTRATIONS FOR NORMAL OPERATION

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[1]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes WA	0.0006	0.0530	0.0015	0.0722	0.0129	0.0005
CRGNSA [4]	0.0129	0.2025	0.0177	0.6061	0.1199	0.0083
Glacier Peak WA	0.0002	0.0274	0.0006	0.0340	0.0062	0.0002
Goat Rocks WA	0.0011	0.0319	0.0020	0.1247	0.0215	0.0007
Mt. Adams WA	0.0021	0.0584	0.0052	0.2109	0.0320	0.0018
Mt. Hood WA	0.0027	0.0683	0.0060	0.2336	0.0389	0.0022
Mt. Jefferson WA	0.0006	0.0539	0.0027	0.0864	0.0189	0.0007
Mt. Rainier NP	0.0016	0.0703	0.0023	0.2570	0.0351	0.0010
Mt. Washington WA	0.0002	0.0409	0.0020	0.0442	0.0109	0.0004
Olympic NP	0.0006	0.0439	0.0014	0.1241	0.0208	0.0005
Three Sisters WA	0.0002	0.0456	0.0020	0.0375	0.0105	0.0004
Class I Area Max. Conc. [4]	*0.0027*	*0.0703*	*0.0060*	*0.2570*	*0.0389*	*0.0022*
USEPA Proposed SIL[2]	*0.1*	*0.3*	*0.2*	*1*	*0.2*	*0.1*
FLM Recommended SIL[2]	*0.03*	*0.27*	*0.08*	*0.48*	*0.07*	*0.03*
Class I Area PSD Increment[3]	*2.5*	*8*	*4*	*25*	*5*	*2*

Notes:

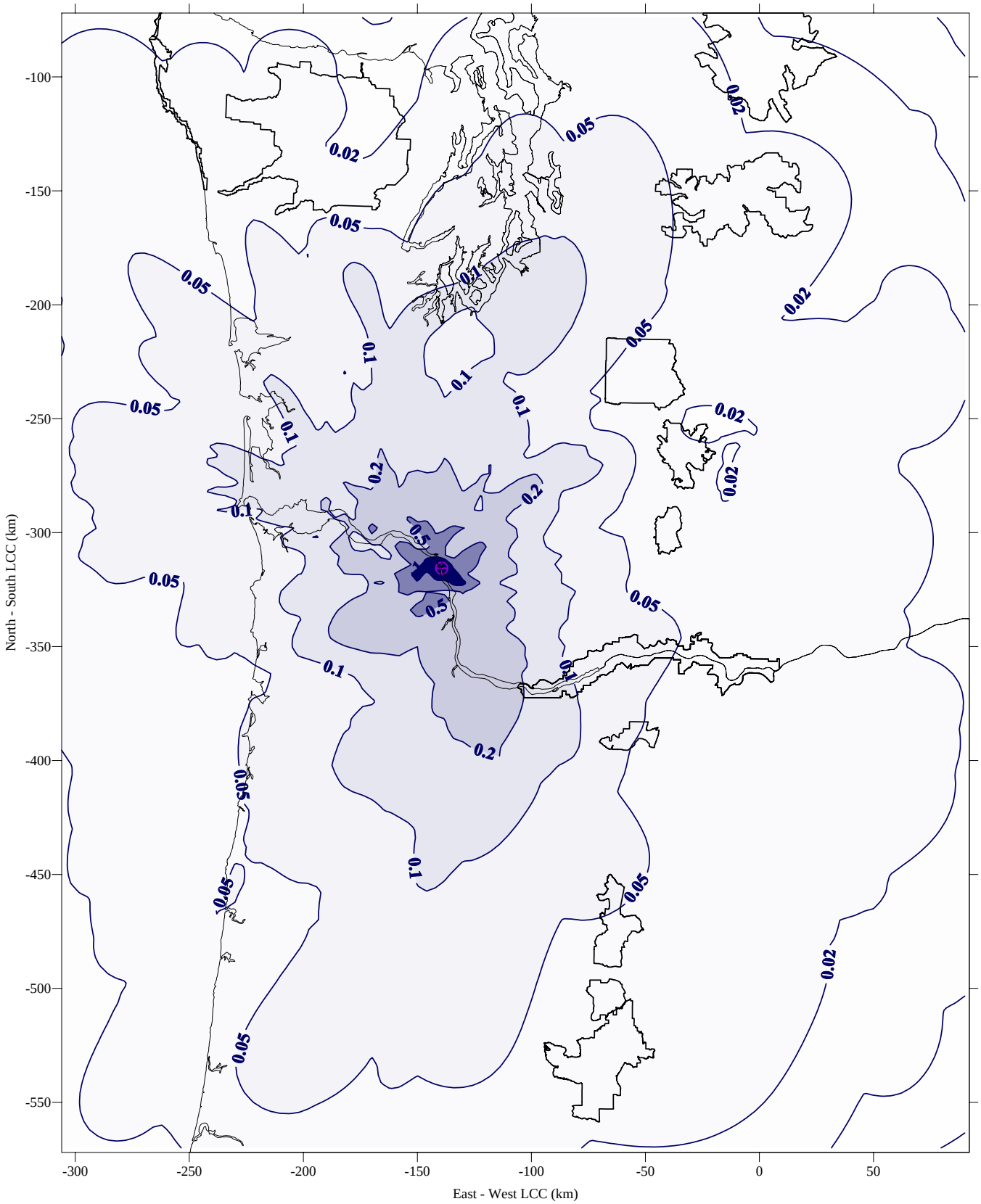
1 NO_x was conservatively assumed to be 100 percent converted to NO_2.

2 SIL = Significant Impact Level; USEPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

3 PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v)

4 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

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 5.1-11 through Figure 5.1-13 present the predicted maximum concentrations for 24-hour PM_{10}, 3-hour SO_2, and annual NO_X. The annual predictions tend to follow the Columbia River near the site, extending north into the western Washington lowlands, and south into the Willamette Valley. The contours also show the influence of regional flow up the Columbia River Gorge and out the mouth of the Columbia River near Astoria. The maximum predictions for the shorter 3- and 24-hour averaging periods occur close to the PMEC site and are less influenced by the prevailing regional wind patterns.

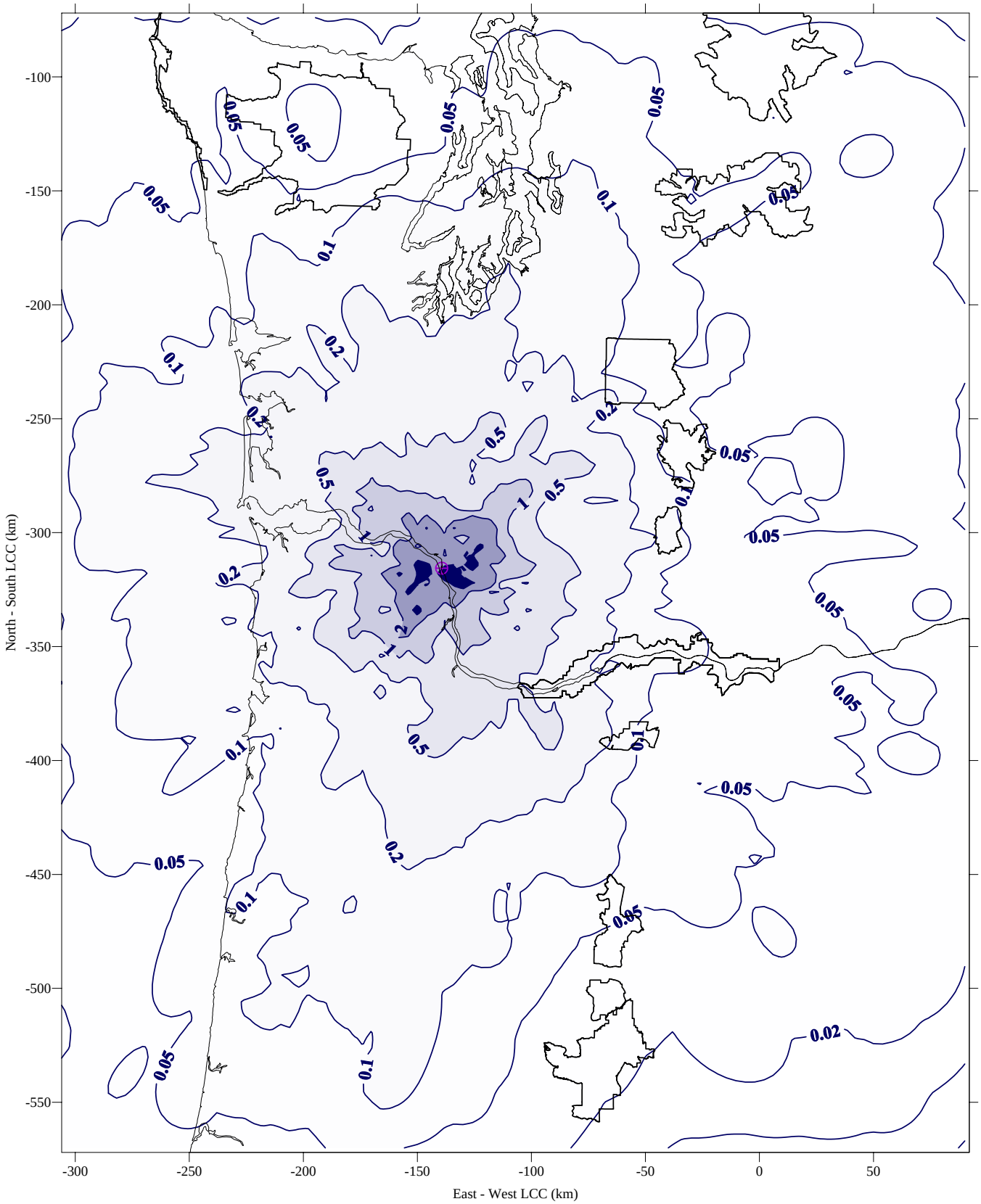


GEOMATRIX

MAXIMUM 24-HOUR PM_{10} CONCENTRATIONS (ug/m^3)
INCLUDES SECONDARY AEROSOLS
Pacific Mountain Energy Center, Kalama, Washington

Project No.
12096.002.0

Figure
5.1-11

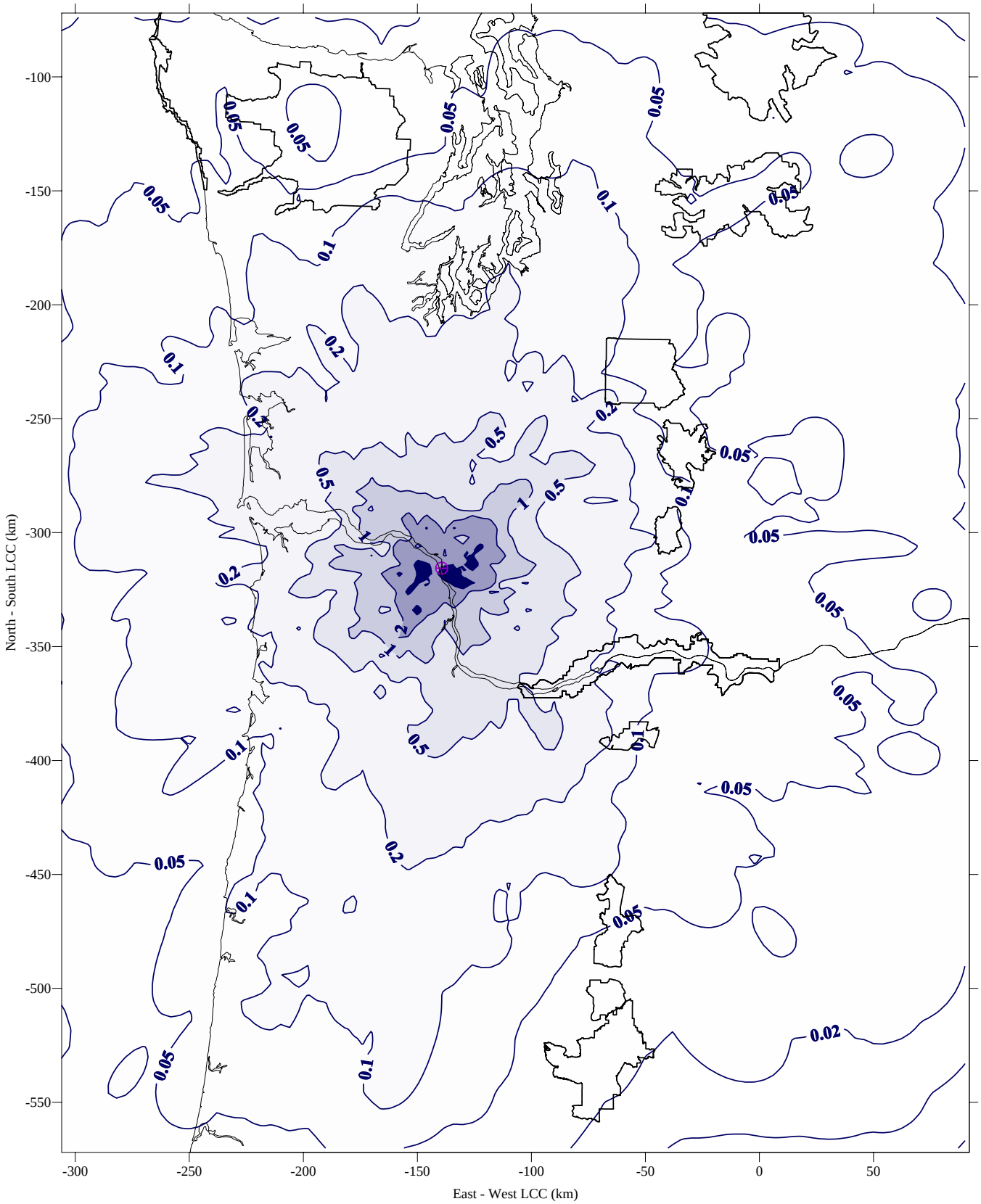


GEOMATRIX

MAXIMUM 3-HOUR SO_2 CONCENTRATIONS (ug/m^3)
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-12



GEOMATRIX

MAXIMUM 3-HOUR SO_2 CONCENTRATIONS (ug/m^3)
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-12

Table 5.1-42 shows the maximum concentrations within each Class I Area and the CRGNSA predicted for the startup emissions case. In order to ensure that the evaluation considered worst-case meteorological conditions, this scenario assumes 24-hour maximum startup emissions occur for every day of the three year simulation. The CALPUFF simulations of startup conditions indicate criteria pollutant concentrations attributable to PMEC are less than the proposed Class I SILs and the increments in all Class I areas.

TABLE 5.1-42
PREDICTED CLASS I AREA AND CRGNSA CRITERIA POLLUTANT CONCENTRATIONS FOR STARTUP

Concentrations in micrograms per cubic meter ($\mu g/m^3$)

Class I and Other Areas of Interest	Maximum Predicted Concentration		
	PM_{10}	SO_2	
	24-Hour Average	3-Hour Average	24-Hour Average
Alpine Lakes WA	0.0674	0.0890	0.0145
CRGNSA [4]	0.2692	0.7125	0.1392
Glacier Peak WA	0.0351	0.0372	0.0083
Goat Rocks WA	0.0424	0.1191	0.0222
Mt. Adams WA	0.0767	0.2225	0.0350
Mt. Hood WA	0.0936	0.2826	0.0437
Mt. Jefferson WA	0.0643	0.0940	0.0207
Mt. Rainier NP	0.0976	0.2916	0.0350
Mt. Washington WA	0.0520	0.0460	0.0111
Olympic NP	0.0546	0.1507	0.0236
Three Sisters WA	0.0592	0.0439	0.0125
Class I Area Max. Conc. [4]	0.0976	0.2916	0.0437
USEPA Proposed SIL[2]	*0.3*	*1*	*0.2*
FLM Recommended SIL[2]	*0.27*	*0.48*	*0.07*
Class I Area PSD Increment[3]	*8*	*25*	*5*

1 NO_x was conservatively assumed to be 100 percent converted to NO_2.

2 SIL = Significant Impact Level; USEPA proposed and FLM recommended from the Federal Register, Vol. 61, No. 142, p. 38292, July 23, 1996.

3 PSD = Prevention of Significant Deterioration; from 40 CFR 52.21(c), adopted by reference in WAC 173-400-720(4)(a)(v)

4 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

The simulations suggest PMEC startup emissions have the potential to results in concentrations over the Federal Land Manager's proposed short-term SO_2 Class I SILs within the CRGNSA. However, the CRGNSA is designated as a Class II area and prediction concentrations from startup emissions are much less than the Class II SILs or PSD increments.

5.1.4.1.4.2 Nitrogen and Sulfur Deposition Fluxes

CALPUFF was applied to predict the impacts of acid-forming compounds emitted by the PMEC 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).[20] 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 CALPUFF simulations for nitrogen and sulfur deposition are summarized in Table 5.1-43 where the maximum annual predictions for each Class I area and the CRGNSA are compared to the NPS nitrogen and sulfur DATs. Figure 5.1-14 and Figure 5.1-15 show the respective spatial variation of the maximum annual predicted sulfur and nitrogen deposition fluxes attributable to the PMEC over the entire simulation domain, respectively. General regional flow tends to direct plumes from the facility away from the Class I areas. Predicted annual deposition fluxes are highest within the Columbia River valley near the PMEC site with local maxima east of the PMEC site in complex terrain. The sulfur deposition patterns show a tendency towards slightly higher predictions east of the facility than indicated by the maximum annual nitrogen deposition fluxes.

The CRGNSA is the area of interest with the highest predicted nitrogen and sulfur deposition fluxes from the PMEC. Westerly flow aloft and large-scale terrain channeling are predicted to sometimes transport PMEC source plumes to the CRGNSA. However, predicted nitrogen and sulfur deposition fluxes within the CRGNSA are less than the NPS screening criteria (0.005 kg/ha/yr), suggesting the PMEC would not significantly affect ARQVs related to nitrogen or sulfur deposition.

5.1.4.1.4.3 Regional Haze

Compliance with the FLMs recommendations for regional visibility impacts was assessed by calculating the percent change in extinction for each Class I receptor. Using the conservative FLAG defaults recommended by the FLMs, the CALPUFF modeling system was applied to predict both the extinction coefficient attributable to emissions from the PMEC and the background extinction coefficients. Regional haze within the CRGNSA was assessed using the same methods, except that the background aerosol concentrations were based on measurements within the CRGNSA not the FLAG defaults representative of "natural" conditions.

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

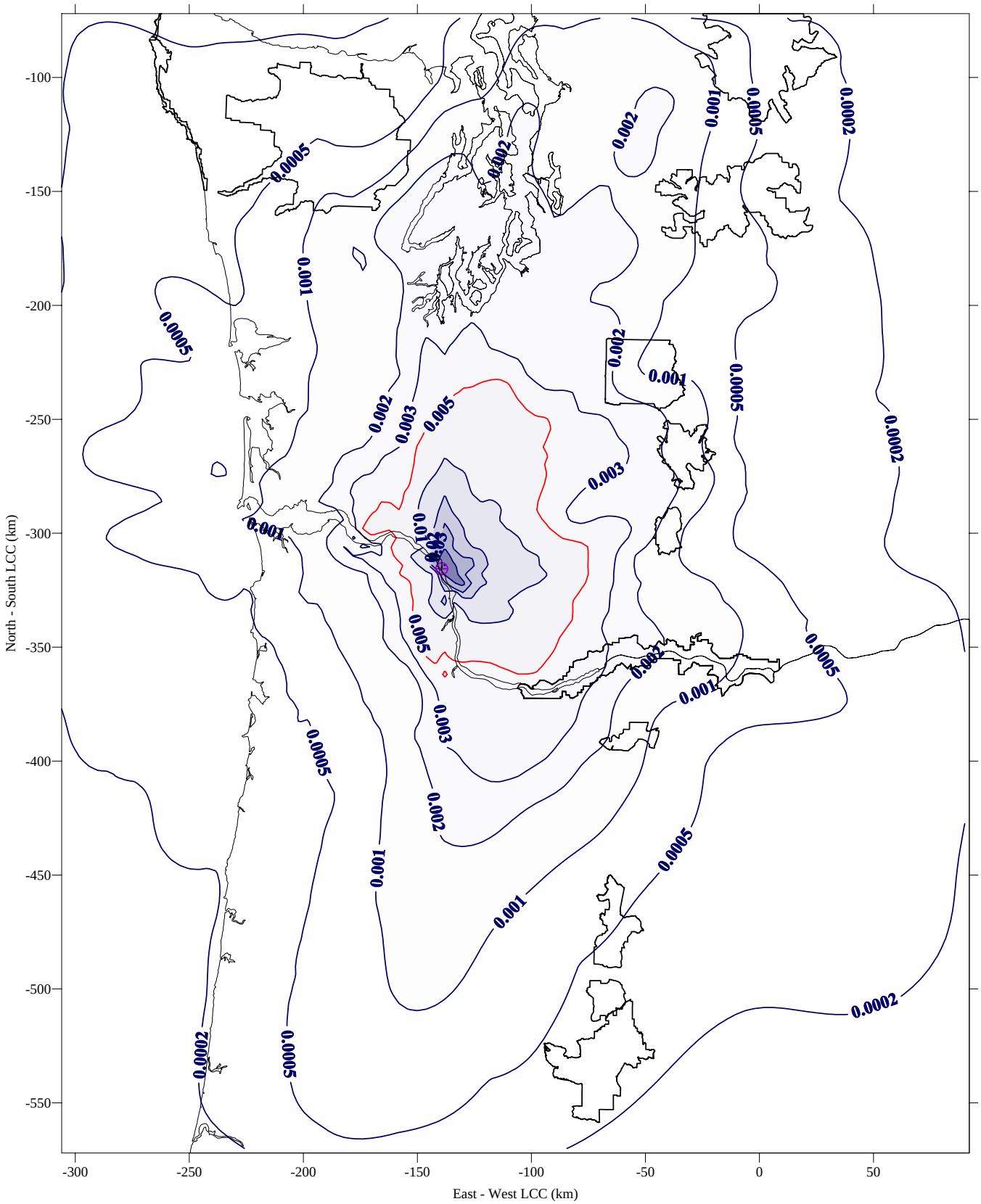
TABLE 5.1-43
PREDICTED CLASS I AREA AND CRGNSA DEPOSITION FLUXES

Deposition fluxes in kilograms per hectare per year (kg/ha/yr)

Class I Area of Interest	Nitrogen Deposition			Change in Nitrogen Deposition (%)	Sulfur Deposition			Change in Sulfur Deposition (%)
	PMEC	Background	Total		PMEC	Background	Total	
Alpine Lakes Wilderness	0.0014	5.2	5.2014	0.03%	0.0017	7.2	7.2017	0.02%
CRGNSA [1]	0.0034	10.0	10.0034	0.03%	0.0045	12.0	12.0045	0.04%
Glacier Peak Wilderness	0.0009	5.8	5.8009	0.02%	0.0011	8.0	8.0011	0.01%
Goat Rocks Wilderness	0.0017	9.0	9.0017	0.02%	0.0022	11.8	11.8022	0.02%
Mt. Adams Wilderness	0.0019	9.0	9.0019	0.02%	0.0022	10.8	10.8022	0.02%
Mt. Hood Wilderness	0.0015	5.4	5.4015	0.03%	0.0021	8.6	8.6021	0.02%
Mt. Jefferson Wilderness	0.0005	1.8	1.8005	0.03%	0.0007	4.0	4.0007	0.02%
Mt. Rainier NP	0.0019	2.4	2.4019	0.08%	0.0025	3.1	3.1025	0.08%
Mt. Washington Wilderness	0.0003	2.6	2.6003	0.01%	0.0005	5.0	5.0005	0.01%
Olympic NP	0.0011	2.0	2.0011	0.05%	0.0017	5.6	5.6017	0.03%
Three Sisters Wilderness	0.0003	3.6	3.6003	0.01%	0.0005	5.6	5.6005	0.01%
NPS DAT	*0.005*				*0.005*			

Note:

1 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

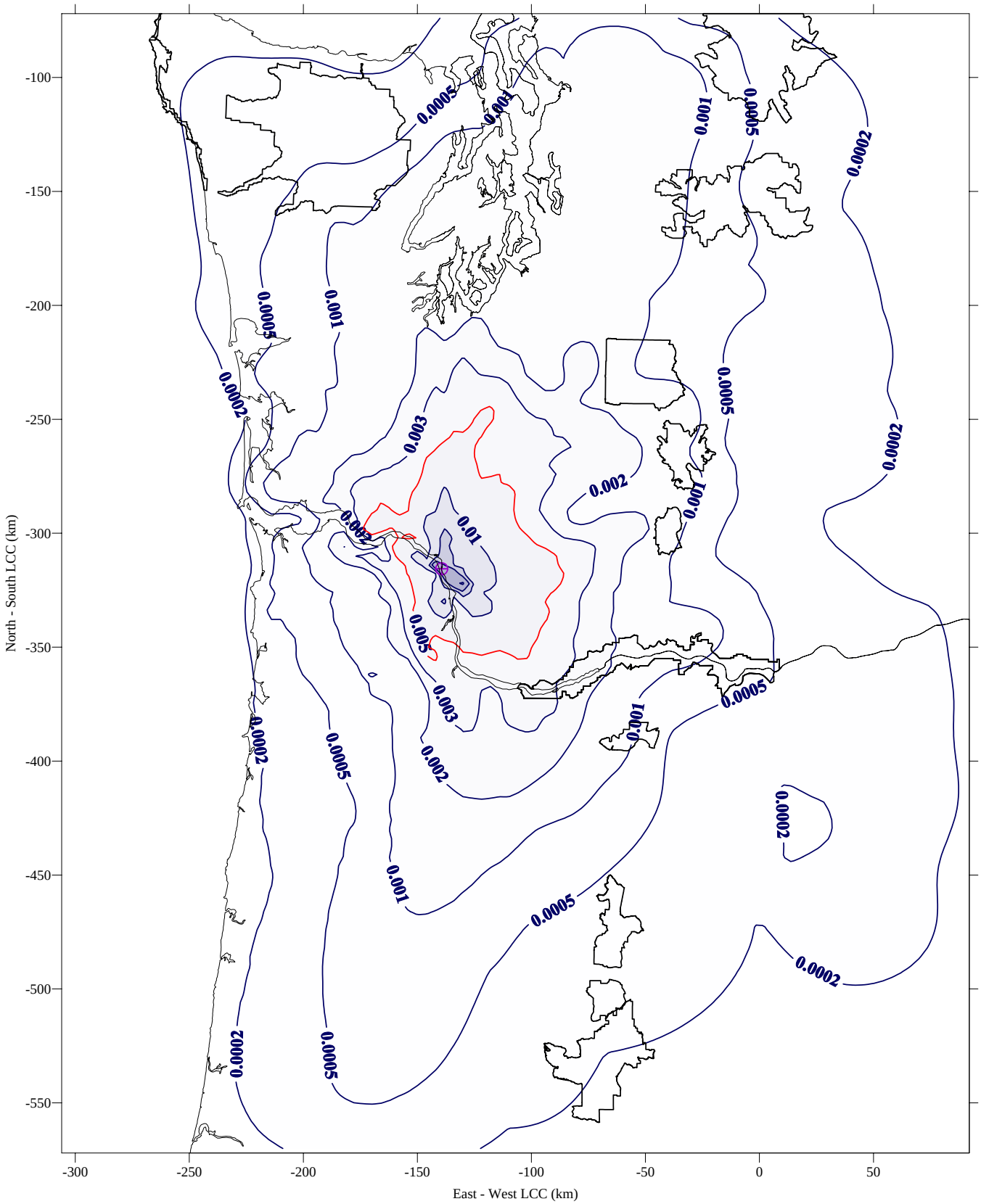


GEOMATRIX

MAXIMUM ANNUAL SULFUR DEPOSITION (KG/HA/YR)
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-14



GEOMATRIX

MAXIMUM ANNUAL NITROGEN DEPOSITION (KG/HA/YR)
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

Figure
5.1-15

The FLMs recommend in the FLAG Phase I Report that a five percent change in extinction be used to indicate a "just perceptible" change to a landscape. Sources that equal or exceed this threshold must perform a cumulative visibility analysis for PSD increment consuming sources. The threshold for the cumulative analysis is a ten percent change, and the threshold for the new source is a contribution of 0.4 percent of the change on those days.

The CALPUFF simulations of the maximum PMEC 24-hour emissions (excluding startup) were compared to the FLM visibility criteria. The ten days with the highest maximum predicted changes in 24-hour extinction in three years are identified in Table 5.1-44. Table 5.1-45 lists the highest prediction in each Class I area and in the CRGNSA. The CRGNSA and Mt. Hood Wilderness Area are the areas predicted to have the highest potential changes to background extinction due to their close proximity to the source and because PMEC plumes are sometimes transported through the Gorge with westerly flow. The other areas of interest are less affected, with occasional higher predictions for the Class I areas in western Washington. The extinction budgets in Table 5.1-44 and Table 5.1-45 indicate nitrate and high relative humidity contribute to most to the extinction coefficients on the worst days. However, the sulfate and organic components also contribute to the extinction budget and sometimes have a combined effect greater than the nitrate aerosols.

Figure 5.1-16 shows contours of the maximum predicted 24-hour extinction in three years due to emissions from the PMEC sources. The highest 24-hour extinction coefficients occur close to the PMEC and are similar to predicted concentration patterns, aligned in a north-south direction with some indications of flow up the CRGNSA.

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 5.1-44 and Table 5.1-45, the maximum predicted change in extinction to a Class I area based on three years of simulation on any day of the simulation was 4.50 percent in the Mt. Hood Wilderness Area, which is less than the five percent threshold established by the FLMs. The predicted maximum changes to extinction for the other Class I areas are typically much lower than the criterion. Based on the FLAG screening criterion, the CALPUFF simulations suggest PMEC emissions would not significantly degrade visibility in regional Class I areas.

TABLE 5.1-44
TEN DAYS WITH MAXIMUM PREDICTED CLASS I AREA AND CRGNSA EXTINCTION CHANGE

Extinction coefficient in inverse megameters (1/Mm)

Class I Area and CRGNSA	Date	b_{ext}[1]			Change (%)	f(RH)	b_{ext} by Component[3]					
		PMEC	Bckgrnd[2]	Total			SO4	NO3	OC	EC	PMC	PMF
CRGNSA [4]	02/27/03	2.68	30.83	33.51	8.68	6.86	0.661	1.540	0.230	0.237	0.000	0.005
CRGNSA [4]	02/08/04	1.72	33.40	35.12	5.16	8.38	0.490	0.905	0.160	0.164	0.000	0.004
CRGNSA [4]	05/18/03	1.36	27.17	28.52	4.99	3.80	0.324	0.518	0.254	0.257	0.000	0.003
CRGNSA [4]	04/06/04	1.34	27.08	28.42	4.95	3.77	0.297	0.528	0.258	0.255	0.000	0.002
CRGNSA [4]	03/16/04	1.30	26.62	27.92	4.88	3.57	0.235	0.610	0.224	0.227	0.000	0.004
CRGNSA [4]	07/31/04	1.48	32.77	34.25	4.51	4.20	0.392	0.473	0.298	0.308	0.000	0.007
Mt. Hood WA	04/04/04	0.79	17.60	18.39	4.50	5.16	0.176	0.409	0.103	0.103	0.000	0.001
Mt. Hood WA	10/01/03	0.74	16.54	17.29	4.49	3.40	0.198	0.371	0.085	0.088	0.000	0.002
CRGNSA [4]	08/16/05	1.35	31.74	33.09	4.24	3.88	0.328	0.387	0.309	0.315	0.000	0.006
Mt. Rainier NP	04/30/05	0.78	18.59	19.37	4.19	6.82	0.215	0.490	0.035	0.037	0.000	0.001

1 PMEC and background extinction values for daily period that resulted in the maximum percent change in extinction.

2 Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity. CRGNSA background aerosol concentrations derived from observations on the 20 percent days with the lowest extinction.

3 Extinction coefficient components are: SO4 = fine sulfate, NO3 = fine nitrate, OC = fine organic carbon, EC = fine elemental carbon, PMC = coarse mass, PMF = fine crustal mass.

4 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.

TABLE 5.1-45
MAXIMUM PREDICTED EXTINCTION CHANGE BY CLASS I AREA AND CRGNSA

Extinction coefficient in inverse megameters (1/Mm)

Class I Area and CRGNSA	Date	b_{ext} [1]			Change (%)	f(RH)	b_{ext} by Component [3]					
		PMEC	Bckgrnd [2]	Total			SO4	NO3	OC	EC	PMC	PMF
Alpine Lakes WA	11/09/04	0.59	17.38	17.97	3.40	4.80	0.140	0.331	0.058	0.060	0.000	0.002
CRGNSA [4]	02/27/03	2.68	30.83	33.51	8.68	6.86	0.661	1.540	0.230	0.237	0.000	0.005
Glacier Peak WA	11/09/04	0.30	17.16	17.46	1.75	4.44	0.077	0.160	0.031	0.032	0.000	0.001
Goat Rocks WA	04/12/04	0.46	18.36	18.82	2.51	6.44	0.152	0.247	0.030	0.032	0.000	0.001
Mt. Adams WA	10/01/03	0.67	16.57	17.24	4.02	3.46	0.183	0.334	0.073	0.075	0.000	0.002
Mt. Hood WA	04/04/04	0.79	17.60	18.39	4.50	5.16	0.176	0.409	0.103	0.103	0.000	0.001
Mt. Jefferson WA	06/23/04	0.35	15.95	16.29	2.16	2.41	0.064	0.104	0.088	0.088	0.000	0.001
Mt. Rainier NP	04/30/05	0.78	18.59	19.37	4.19	6.82	0.215	0.490	0.035	0.037	0.000	0.001
Mt. Washington WA	03/09/04	0.37	18.82	19.19	1.97	7.21	0.107	0.217	0.022	0.023	0.000	0.001
Olympic NP	01/20/04	0.39	17.99	18.38	2.17	5.81	0.086	0.216	0.043	0.044	0.000	0.001
Three Sisters WA	10/02/03	0.45	17.14	17.59	2.62	4.40	0.125	0.209	0.056	0.057	0.000	0.001

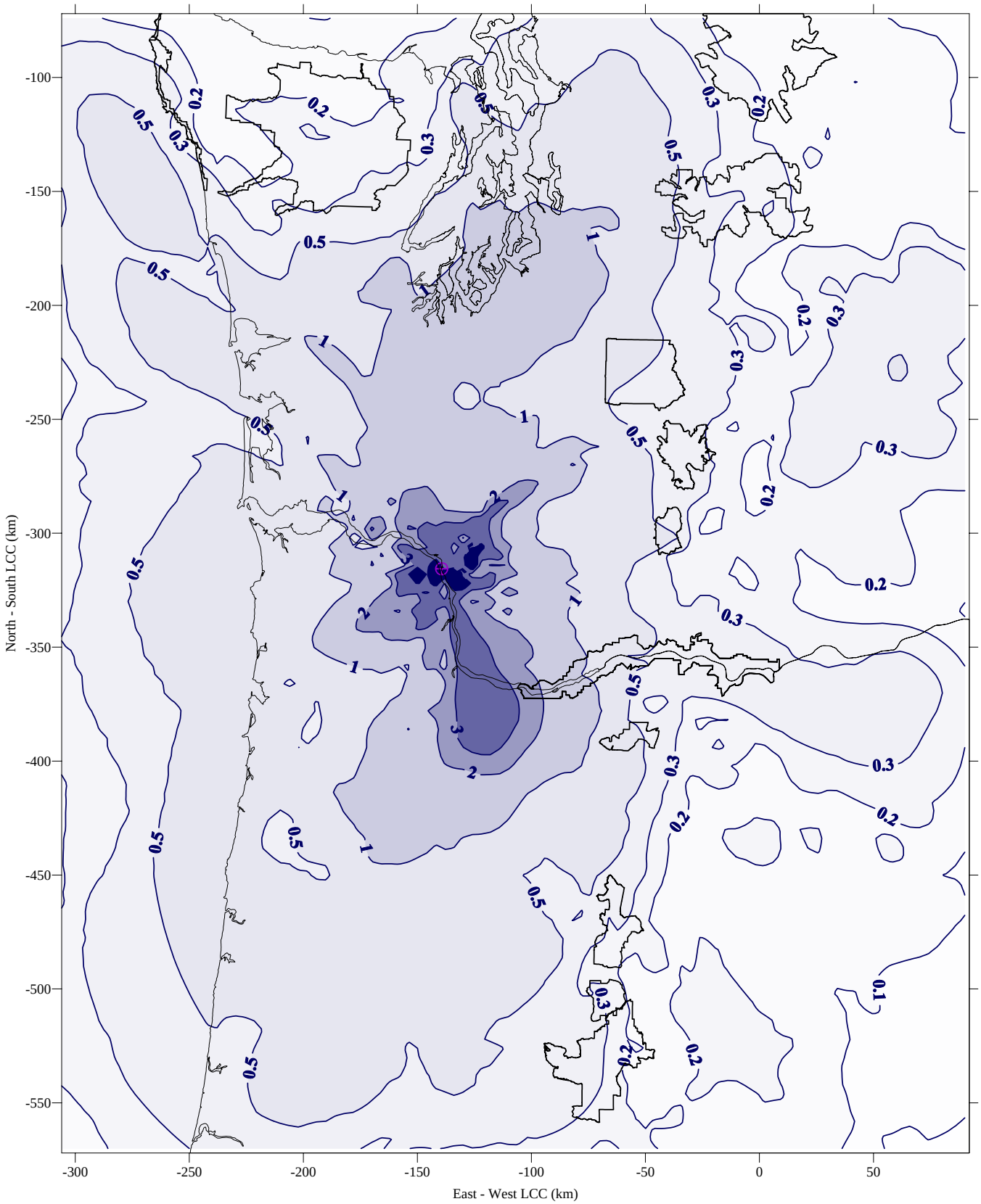
Notes:

1 PMEC and background extinction values for daily period that resulted in the maximum percent change in extinction.

2 Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity. CRGNSA background aerosol concentrations derived from observations on the 20 percent days with the lowest extinction.

3 Extinction coefficient components are: SO4 = fine sulfate, NO3 = fine nitrate, OC = fine organic carbon, EC = fine elemental carbon, PMC = coarse mass, PMF = fine crustal mass.

4 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.



GEOMATRIX

MAXIMUM 24-HOUR EXTINCTION (1/Mm) EXCLUDING BACKGROUND
Pacific Mountain Energy Center
Kalama, Washington

Project No.
12096.002.0

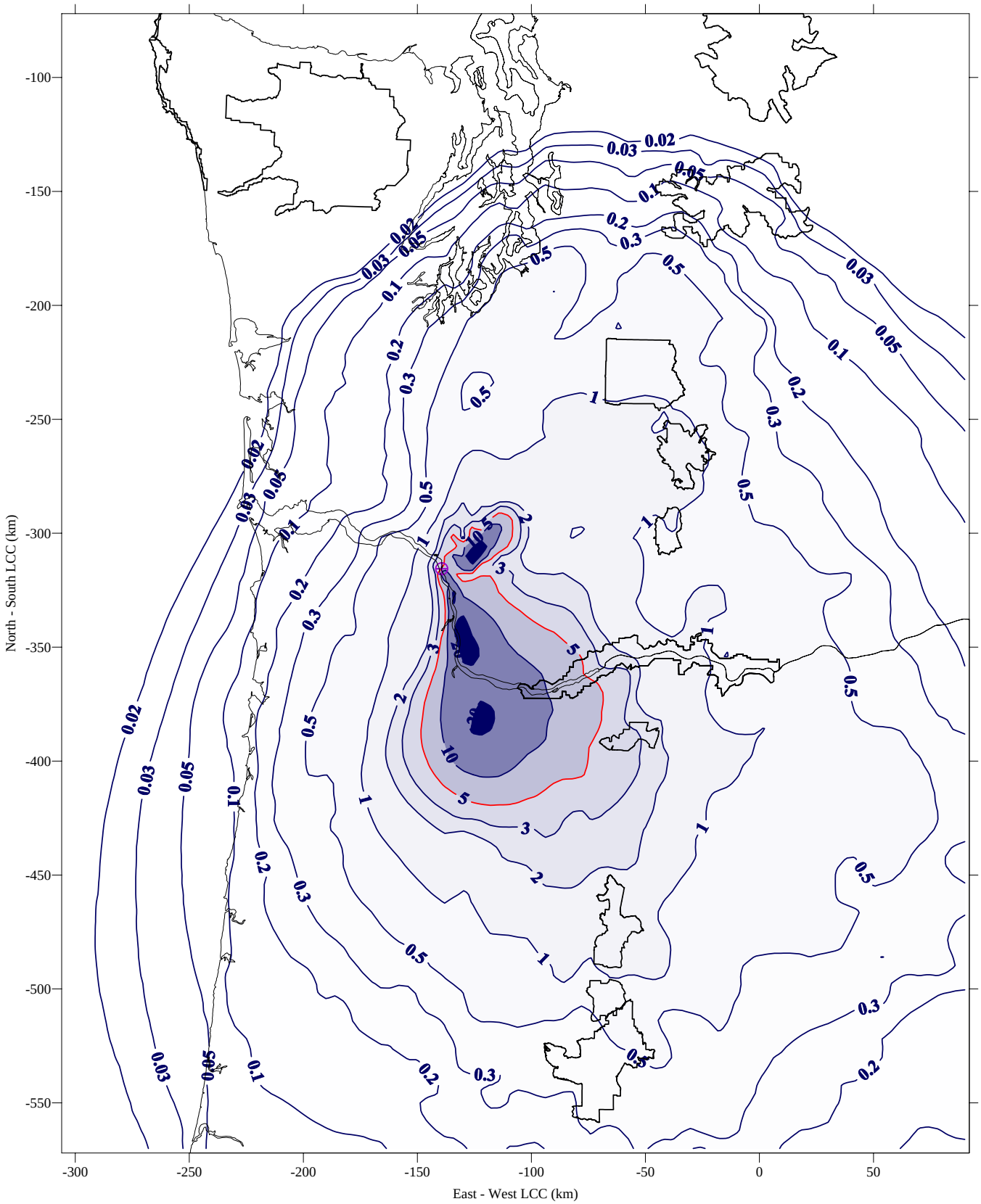
Figure
5.1-16

The five percent FLM criterion for Class I areas was exceeded for two days in three years for receptors within the western portions of the CRGNSA. Figure 5.1-17 and Figure 5.1-18 present contour plots of the predicted change to extinction caused by emissions attributable to the PMEC on the these two days (February 27, 2003 and February 8, 2004).[21] On both of these days, light winds were prevalent, with seasonably cool temperatures and high humidity. The evening/early morning hours were 100 percent overcast followed by partial clearing in the late morning. The cool temperatures and high humidity contributes to nitrate formation and stagnation persisted throughout most of the day.

Although the predicted change to extinction in a small portion of the CRGNSA exceeds the FLM criteria of five percent on two days in three years, increased emissions from the PMEC are not expected to significantly degrade visibility due to a number of conservative assumptions in the modeling approach:

- The modeling procedures for background extinction assume low aerosol concentrations and excellent visibility. They do not consider weather obscuration often associated with high relative humidity and cold temperature in the Pacific Northwest. On February 27, 2003 and February 8, 2004 stations in the Portland area reported 100 percent cloud cover and low ceiling heights for many hours within the 24-hour period. Such conditions would not be conducive to good visibility in the Gorge.
- The extinction budgets shown in Table 5.1-44 and Table 5.1-45 indicate that sulfate aerosols are responsible for the significant portions of extinction on the worst days. A portion of the sulfate aerosol is the result of the sulfate in the $PM_{2.5}$ directly emitted by the turbines. The analysis "double counts" the sulfur emitted by the turbines because SO_2 emissions have not been reduced to account for the sulfate in the $PM_{2.5}$ emitted.
- Figure 5.1-17 and Figure 5.1-18 show the change to extinction predicted for February 27, 2003 and February 8, 2004, respectively. Note, the PMEC's plume only affects a small corner of the CRGNSA and the change to extinction is not uniform or representative of a long optical path length. The FLM criteria are based on the assumption that the change to extinction is representative of "regional haze" across lines of sight that are close to the visual range. The standard visual ranges predicted for these day were between 110 km to 120 km, much longer than any reasonable line of site within the CRGNSA affected by the PMEC plumes on these days.

[21] The contour plot in Figure 5.1-18 and Figure 5.1-19 were 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



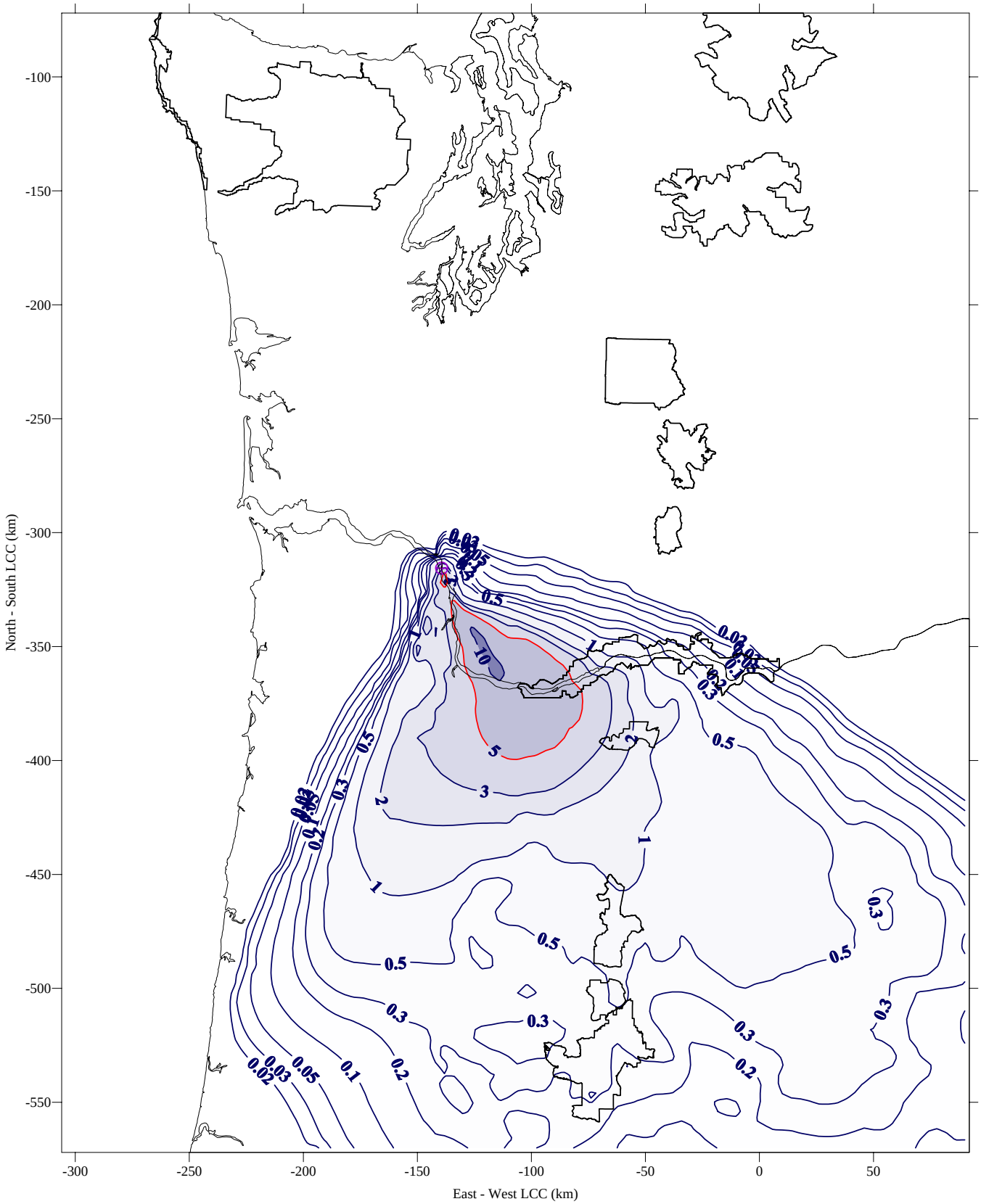
GEOMATRIX

CHANGE TO 24-HOUR EXTINCTION (%) FROM "NATURAL" BACKGROUND ON FEBRUARY 27, 2003

Pacific Mountain Energy Center, Kalama, Washington

Project No. 12096.002.0

Figure **5.1-17**



GEOMATRIX

CHANGE TO 24-HOUR EXTINCTION (%) FROM "NATURAL" BACKGROUND ON FEBRUARY 8, 2004

Pacific Mountain Energy Center, Kalama, Washington

Project No. 12096.002.0

Figure **5.1-18**

- High relative humidity on February 27, 2003 and February 8, 2004 increased the scattering efficiencies of the hygroscopic aerosols. The humidity adjustment factor was 6.86 and 8.38 for these two days as shown in Table 5.1-44. It has been common practice for Class I assessments in Washington state to use predicted hourly relative humidity to calculate the extinction coefficient. However, the FLMs allow the use of seasonal relative humidity adjustment factors to estimate background natural visibility.[11,17] These seasonal factors remove some of the effects of high humidity caused by weather obscuring events. For example, the winter season humidity adjustment factor associated with the background extinction used in the CRGNSA (Table 5.1-40) is 3.97, much lower than 6.86 used in the calculation on February 27, 2003. When the FLM recommended seasonal factors are applied to the days shown in Table 5.1-44, all the predicted changes to extinction in the CRGNSA are less than the five percent criterion.

Consequently, PMEC emissions are not expected to significantly degrade visibility in CRGNSA or any Class I area.

The discussion above concerned the CALPUFF simulations of maximum 24-hour emissions under the duct-firing scenario. At Ecology's request, CALPUFF simulations were also performed assuming startup conditions for every day in the three year simulation period. The results of these simulations are shown in Table 5.1-46. Using the startup emissions in Table 5.1-36, the potential change to extinction exceeds the FLM five percent criterion in three Class I areas and the CRGNSA. These potential meteorological events were predicted for seven days in three years at receptors within the CRGNSA. The joint probability that a worst case meteorological event would be combined with such a startup is less than one day per year.

5.1.5 ADDITIONAL IMPACT ANALYSIS

5.1.5.1 Class II Area Growth

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

PMEC would consume natural gas delivered by pipeline and solid feedstocks delivered by train, ship, or barge. 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. However, operation of the facility will require a work force of approximately 80-100 people. By comparison, the neighboring Steelscape and Noveon Kalama facilities employ approximately 305 and 158, respectively. Energy Northwest does not expect PMEC to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

TABLE 5.1-46
PREDICTED MAXIMUM CHANGES TO EXTINCTION ON CLASS I AREA AND CRGNSA FOR UNDER STARTUP CONDITIONS

Class I Area and CRGNSA	Maximum Predicted Change to Extinction from Natural Background (%) [1]			Potential Days > 5% Change (days in 3 years) [2]	Probable Days > 5% Change (days per year) [3]
	2003	2004	2005		
Alpine Lakes WA	2.53	4.65	2.61	0	0.00
CRGNSA [4]	12.27	6.88	5.13	7	0.12
Glacier Peak WA	1.1	2.5	1.76	0	0.00
Goat Rocks WA	3.09	3.6	2.29	0	0.00
Mt. Adams WA	5.4	5.04	3.71	3	0.05
Mt. Hood WA	6.06	6.9	4.48	3	0.05
Mt. Jefferson WA	2.97	2.78	1.54	0	0.00
Mt. Rainier NP	4.26	4.11	5.91	1	0.02
Mt. Washington WA	2.19	2.7	0.89	0	0.00
Olympic NP	2.45	3.42	2.55	0	0.00
Three Sisters WA	3.7	3.1	0.84	0	0.00

Notes:

1 Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity. CRGNSA background aerosol concentrations derived from observations on the 20 percent days with the lowest extinction.

2 Number of days in three years where the predicted change to extinction exceeded 5 percent assuming startup emissions occur every day.

3 Number of probable days per year where the predicted change to extinction exceeded 5 percent assuming startup emissions occur 18 days per year

4 The CRGNSA is not a Class I area, but is included in the analysis at the request of Ecology and the FLMs.

5.1.5.2 Class II Visibility

On a large spatial scale, visibility is typically evaluated as "regional haze." The application addresses regional haze in the discussion of 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 ASC addresses local (Class II) visibility impacts in Section 3.2.3. Additional detail is provided in Appendix B-2.

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

However, the PMEC design includes two 6-cell cooling towers and one 7-cell cooling tower to exhaust waste heat. The PMEC 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.

Geomatrix conducted an analysis of potential cooling tower impacts using the Seasonal/Annual Cooling Tower Impact (SACTI, Version 11-01-90) model and meteorological data from Noveon Chemical. These meteorological data were also used in the air quality dispersion modeling assessment for the facility. As noted in Section 3.2.3, the conclusions of that modeling analysis are as follows:

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

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. The ASC for PMEC includes a discussion of 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 National Ambient Air Quality Standards were established to protect the public health and welfare, and secondary standards were identified specifically to protect ecological properties such as soils and vegetation. The PMEC air quality assessment indicates that NAAQS would be protected, and that 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 AND STORMWATER DISCHARGE PERMIT APPLICATION (WAC 463-60-537)

5.2.1 WASTEWATER DISCHARGE

The Pacific Mountain Energy Center (PMEC) will need a federal National Pollutant Discharge Elimination System (NPDES) permit for wastewater discharges to the Columbia River. It is planned to discharge PMEC's industrial wastewater to the mixing vault for the combined domestic and industrial wastewater system of the Port of Kalama (Figure 2-7.3), and thence to the Port's outfall to the Columbia River. PMEC is required to comply with any pre-treatment requirements to ensure that the terms of the Port of Kalama's NPDES permit are not violated.

A water balance diagram is shown on the following page as Figure 5.2-1.

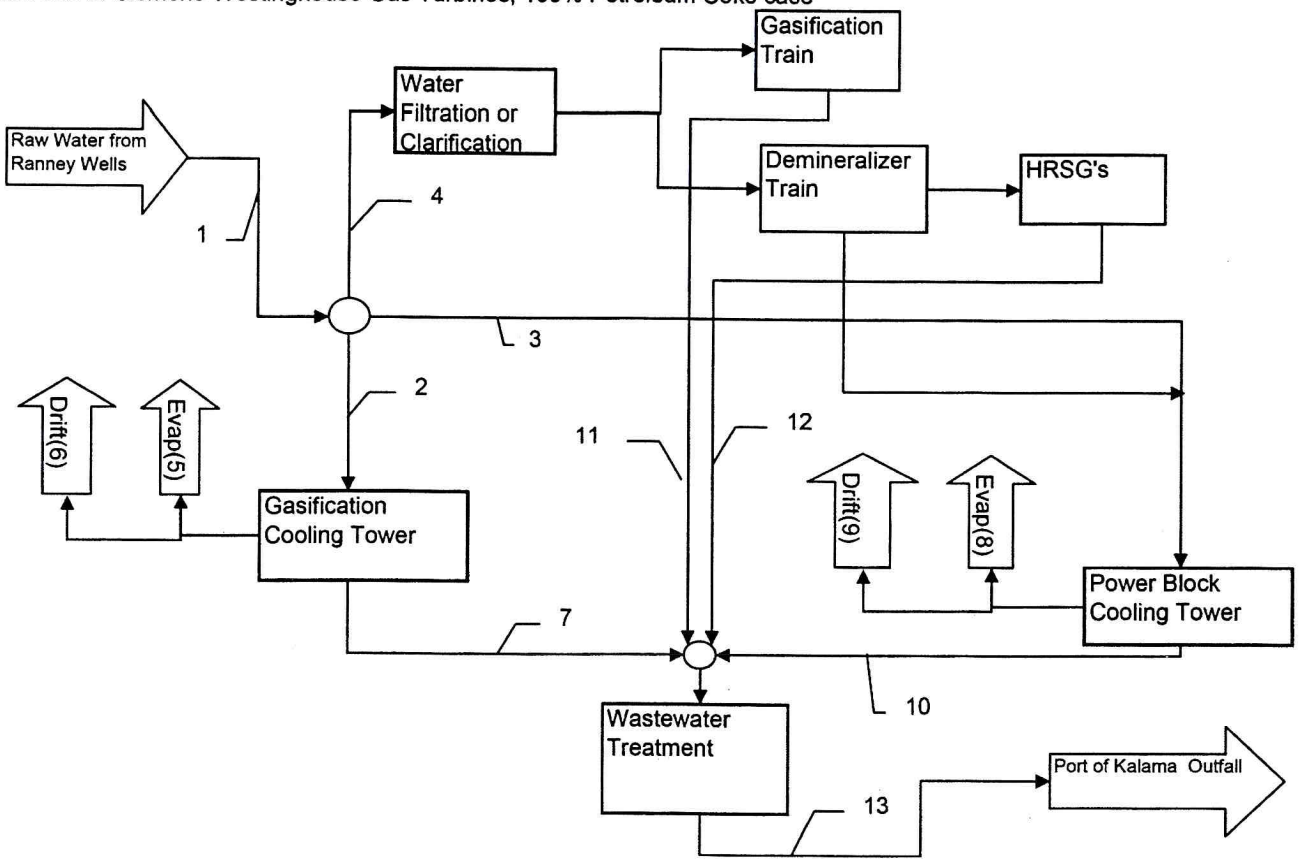
In order to comply with the EPA Consolidated Permits Program, the following forms are expected to be needed: Form 1 (General Information), Form 2D (Discharge to Surface Waters), and Form 5 (Stationary Air Pollution Source). Forms 1 and 2D have been initially completed and are included in this application. Form 5, which are currently under revision by the EPA and not available on their website, will be added when available.

5.2.2 STORMWATER DISCHARGE

Coverage for stormwater discharges will be sought under the State of Washington Stormwater Industrial Stormwater General Permit. The application will include submitting a Notice-of-Intent (NOI) form to be covered under this permit, and preparing the required public notices of such intent. The application will be filed approximately 90 days prior to the start of operation.

Energy Northwest Pacific Mountain Energy Center IGCC Plant

Assumes use of Siemens-Westinghouse Gas Turbines, 100% Petroleum Coke case



Number	1	2	3	4	5	6	7	8	9	10	11	12	13
Description	Raw water from Ranney Wells	Gasification Cooling Tower Makeup	Power Block Cooling Tower Makeup	Process Water Inlet	Evaporation from Gasification Cooling Tower	Drift from Gasification Cooling Tower	Blowdown from Gasification Cooling Tower	Evaporation from Power Block Cooling Tower	Drift from Power Block Cooling Tower	Blowdown from Power Block Cooling Tower	Gasifier Blowdown	HRSG Blowdown	Wastewater to Outfall
Flow (gpm)	5260	1204	3524	532	963	32	209	2819	94	611	70	XX	890
TDS (mg/L)					0	(high)	(high)	0	(high)	(high)		(low)	(high)
Temp (°F)													

Job No. 33758342

Figure 5.2-1
Water Balance

URS

Pacific Mountain Energy Center
Kalama Washington

Please print or type in the unshaded areas only
(fill-in areas are spaced for elite type, i.e., 12 characters/inch).

For Approved. OMB No. 2040-0086. Approval expires 5-31-92

FORM 1 GENERAL

U.S. ENVIRONMENTAL PROTECTION AGENCY

GENERAL INFORMATION

Consolidated Permits Program

(Read the "General Instructions" before starting.)

I. EPA I.D. NUMBER

S F		T/A	C D
1	2 13	14	15

LABEL ITEMS

- I. EPA I.D. NUMBER
- III. FACILITY NAME
- V. FACILITY MAILING LIST
- VI. FACILITY LOCATION

PLEASE PLACE LABEL IN THIS SPACE

GENERAL INSTRUCTIONS

If a preprinted label has been provided, affix it in the designated space. Review the information carefully; if any of it is incorrect, cross through it and enter the correct data in the appropriate fill-in area below. Also, if any of the preprinted data is absent *(the area to the left of the label space lists the information that should appear)*, please provide it in the proper fill-in area*(s)* below. If the label is complete and correct, you need not complete Items I, III, V, and VI*(except VI-B which must be completed regardless)*. Complete all items if no label has been proved. Refer to the instructions for detailed item descriptions and for the legal authorization under which this data is collected.

II. POLLUTANT CHARACTERISTICS

INSTRUCTIONS: Complete A through J to determine whether you need to submit any permit application forms to the EPA. If you answer "yes" to any questions, you must submit this form and the supplemental from listed in the parenthesis following the question. Mark "X" in the box in the third column if the supplemental form is attached. If you answer "no" to each question, you need not submit any of these forms. You may answer "no" if your activity is excluded from permit requirements; see Section C of the instructions. See also, Section D of the instructions for definitions of **bold-faced terms**.

SPECIFIC QUESTIONS	MARK "X" YES	NO	FORM ATTACHED	SPECIFIC QUESTIONS	MARK "X" YES	NO	FORM ATTACHED
A. Is this facility a **publicly owned treatment works** which results in a **discharge** to **waters of the U.S.?** (FORM 2A)	☐ 16	☒ 17	☐ 18	B. Does or will this facility *(either existing or proposed)* include a **concentrated animal feeding operation** or **aquatic animal production facility** which results in a **discharge** to **waters of the U.S.?** (FORM 2B)	☐ 19	☒ 20	☐ 21
C. Is this facility which currently results in **discharges to waters of the U.S.** other than those described in A or B above? (FORM 2C)	☐ 22	☒ 23	☐ 24	D. Is this proposal facility *(other than those described in A or B above)* which will result in a **discharge** to **waters of the U.S.?** (FORM 2D)	☒ 25	☐ 26	☐ 27
E. Does or will this facility treat, store, or dispose of **hazardous wastes?** (FORM 3)	☒ 28	☐ 29	☐ 30	F. Do you or will you inject at this facility industrial or municipal effluent below the lowermost stratum containing, within one quarter mile of the well bore, underground sources of drinking water? (FORM 4)	☐ 31	☒ 32	☐ 33
G. Do you or will you inject at this facility any produced water other fluids which are brought to the surface in connection with conventional oil or natural gas production, inject fluids used for enhanced recovery of oil or natural gas, or inject fluids for storage of liquid hydrocarbons? (FORM 4)	☐ 34	☒ 35	☐ 36	H. Do you or will you inject at this facility fluids for special processes such as mining of sulfer by the Frasch process, solution mining of minerals, in situ combustion of fossil fuel, or recovery of geothermal energy? (FORM 4)	☐ 37	☒ 38	☐ 39
I. Is this facility a proposed **stationary source** which is one of the 28 industrial categories listed in the instructions and which will potentially emit 100 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an **attainment area**? (FORM 5)	☒ 40	☐ 41	☐ 42	J. Is this facility a proposed **stationary source** which is NOT one of the 28 industrial categories listed in the instructions and which will potentially emit 250 tons per year of any air pollutant regulated under the Clean Air Act and may affect or be located in an **attainment are?** (FORM 5)	☐ 43	☒ 44	☐ 45

III. NAME OF FACILITY

C 1 | SKIP | ***Pacific Mountain Energy Center (PMEC)***

15 | 16-29 | 30 ... 69

IV. FACILITY CONTACT

	A. NAME & TITLE *(last, first, & title)*	B. PHONE *(area code & no.)*		
C 2	***Thomas Krueger, Project Manager, Generation Project Development***	***509***	***377***	***4761***
15	16 ... 45	46 48	49 51	52 55

V. FACILITY MAILING ADDRESS

A. STREET OR P.O. BOX

C 3 | ***PO Box 968***

15 | 16 ... 45

B. CITY OR TOWN	C. STATE	D. ZIP CODE
C 4 ***Richland***	***WA***	***99352***
15 16 ... 40	41 42	47 51

VI. FACILITY LOCATION

A. STREET, ROUTE NO. OR OTHER SPECIFIC IDENTIFIER

C 5 | ***TBD (near 46°2'30"N, 122°52'0"W)***

15 | 16 ... 45

B. COUNTY NAME

owlitz

... 70

C. CITY OR TOWN	D. STATE	E. ZIP CODE	F. COUNTY CODE
C 6 ***Kalama***	***WA***		
15 16 ... 40	41 42	47 51	52 54

CONTINUED ON REVERSE

CONTINUED FROM THE FRONT

VII. SIC CODES (4-digit, in order of priority)

A. FIRST		B. SECOND	
C 7	4911	(specify) Electric Services	
C. THIRD		D. FOURTH	
		(specify)	

VIII. OPERATOR INFORMATION

A. NAME: Energy Northwest

B. Is the name listed in Item VIII-A also the owner? ☒ YES ☒ NO

C. STATUS OF OPERATOR (Enter the appropriate letter into the answer box; if "Other," specify.)
F = FEDERAL
S = STATE
P = PRIVATE
M = PUBLIC (other than federal or state)
O = OTHER (specify)

M (specify)

D. PHONE (area code & no.): 360 673 3350

E. STREET OR PO BOX: P.O. Box 1960

F. CITY OR TOWN: Kalama

G. STATE: WA

H. ZIP CODE: 98625

IX. INDIAN LAND

Is the facility located on Indian lands? ☐ YES ☒ NO

X. EXISTING ENVIRONMENTAL PERMITS

A. NPDES (Discharges to Surface Water)	C 9 T N I	WA0040843 (Port of Kalama, adjacent to proposed facility)	
B. UIC (Underground Injection of Fluids	C 9 T U I		
C. RCRA (Hazardous Wastes)	C 9 T R I		
D. PSD (Air Emissions from Proposed Sources)	C 9 T P I		
E. OTHER (specify)	C 9 T I		(Specify)
E. OTHER (specify)	C 9 T I		(Specify)

XI. MAP

Attach to this application a topographic map of the area extending to at least one mile beyond property boundaries. The map must show the outline of the facility, the location of each of its existing and proposed intake and discharge structures, each of its hazardous waste treatment, storage, or disposal facilities, and each well where it injects fluids underground. Include all springs, rivers and other surface water bodies in the map area. See instructions for precise requirements.

XII. NATURE OF BUSINESS (provide a brief description)

Energy Northwest is proposing to construct and operate the Pacific Mountain Energy Center (PMEC), an Integrated Gasification Combined Cycle (IGCC) development, which will gasify petroleum coke or coal to power two 300 MW combined cycle combustion turbine electric power generating plants.

In the gasification process, petroleum coke, coal, or blends of coal and petroleum coke are pulverized and transported into a pressurized vessel (the gasifier) along with sub-stoichiometric amounts of purified oxygen. In the gasifier, controlled reactions take place, thermally converting feed stock materials into a low British Thermal Unit (BTU) gaseous fuel known as synthesis gas or syngas. The syngas is cooled, cleaned of contaminants, and then combusted in a combustion turbine, which is directly connected to an electric generator.

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

The gasification process is integrated with the combined cycle electric power generating plant to improve efficiencies and optimize performance. The combined complex is known as IGCC, an inherently lower polluting technology application to produce electricity from solid feed stocks. Additionally, the PMEC will have the capability of using natural gas as a back up fuel for the electric power generating plants.

XIII. CERTIFICATION (see instructions)

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this application and all attachments and that, based on my inquiry of those persons immediately responsible for obtaining the information contained in the application, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

A. NAME & OFFICIAL TITLE (type or print)	B. SIGNATURE	C. DATE SIGNED
Thomas Krueger, Project Manager, Generation Project Development	Thomas W Krueger	8/31/06

COMMENTS FOR OFFICIAL USE ONLY

Please type or print in the unshaded areas only	EPA ID Number *(Copy from Item 1 of Form 1)*	*Form Approved OMB No. 2040-0086 Approval expires 7-31-88*

Form **2D** NPDES

New Sources and New Dischargers Application for Permit to Discharge Process Wastewater

I. Outfall Location

For this outfall, list the latitude and longitude, and name of the receiving water(s)

Outfall Number *(list)*	Latitude			Longitude			Receiving Water *(name)*
	Deg	Min	Sec	Deg	Min	Sec	
1 (existing Port of Kalama outfall)	***46***	***2***	***30***	***122***	***52***	***28***	***Columbia River***

II. Discharge Date *(When do you expect to begin discharging?))*

TBD

III. Flows, Sources of Pollution, and Treatment Technologies

A. For each outfall, provide a description of (1) all operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and stormwater runoff; (2) the average flow contributed by each operation; and (3) the treatment received by the wastewater. Continue on additional sheets if necessary.

Outfall Number	1. Operations Contributing Flow *(list)*	2. Average Flow *(include units)*	3. Treatment *(Description of list Codes from Table 2D-1)*
1	***Cooling Tower Blowdown***	***820 gpm***	***TBD***
1	***HRSG Blowdown***	***11 gpm***	***TBD***
1	***Demineralizer Rinse***	***31 gpm***	***TBD***
1	***Gasification Island Wastewater***	***28 gpm***	***TBD***
1	***Condensate from Air Separation Unit Intercoolers***	***TBD***	***TBD***

B. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item III-A. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfalls. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

C. Except for storm runoff, leaks, or spills, will any of the discharges described in Item III-A be intermittent or seasonal?

☐ Yes *(complete the following table)* ☒ No *(go to Item IV)*

Outfall Number	1. Frequency		2. Flow		
	a. Days Per Week *(specify average)*	b. Months Per Year *(specify) average)*	a. Maximum Daily Flow Rate *(in mgd)*	b. Maximum Total Volume *(specify with units)*	c. Duration *(in days)*
N/A					

IV. Production

If there is an applicable production-based effluent guideline or NSPS, for each outfall list the estimated level of production (projection of actual production level, not designed), expressed in the terms and units used in the applicable effluent guideline or NSPS, for each of the first 3 years of operation. If production is likely to vary, you may also submit alternative estimates (attach a separate sheet).

Year	a. Quantity Per Day	b. Units of Measure	c. Operation, Product, Material, etc *(specify)*
N/A			*N/A*
N/A			*N/A*
N/A			*N/A*

 CONTINUE ON NEXT PAGE

CONTINUED FROM THE FRONT	EPA ID Number *(cop from Item 1 of Form 1)*	Outfall Number *1*

V. Effluent Characteristics

A and B: These items require you to report estimated amounts *(both concentration and mass)* of the pollutants to be discharged from each of your outfalls. Each part of this item addresses a different set of pollutants and should be completed in accordance with the specific instruction for that part. Data for each outfall should be on a separate page. Attach additional sheets of paper if necessary.

General Instructions *(See Table 2D-2 for Pollutants)*

Each part of this item requests you to provide an estimated daily maximum and average for certain pollutants and the source of information. Data for all pollutants in Group A, for all outfalls, must be submitted unless waived by the permitting authority. For all outfalls, data for pollutants in Group B should be reported only for pollutants which you believe will be present or are limited directly by an effluent limitations guideline or NSPS or indirectly through limitations on an indicator pollutant.

1. Pollutant	2. Maximum Daily Value *(include units)*	3. Average Daily Value *(include units)*	4. Source *(see instructions)*
BOD			***All values based solely on raw water concentrated 12 times (i.e. cooling tower blowdown).***
COD			
TOC			
TSS			
NH3 (as N)			
Temp (Winter / Summer)	***Winter: TBD***	***Summer: TBD***	
pH		***6.3***	
Silica (as SiO2)		***132 ppmw***	
Iron		***156 ppmw***	
Manganese		***24 ppmw***	
Calcium		***492 ppmw***	
Magnesium		***168 ppmw***	
Sodium		***108 ppmw***	
Potassium		***12 ppmw***	
Carbonate		***2.4 ppmw***	
Bicarbonate		***720 ppmw***	
Sulfate		***30 ppmw***	
Chloride		***30 ppmw***	
Fluoride		***3.6 ppmw***	
Nitrate		***3.6 ppmw***	
Mercury		***0.006 ppmw***	
Selenium		***0.12 ppmw***	
Arsenic		***0.06 ppmw***	
Lead		***0.012 ppmw***	
Zinc		***0.072 ppmw***	
Silver		***0.012 ppmw***	
Hardness (as CaCO3)		***1920 ppmw***	

CONTINUED FROM THE FRONT	EPA ID Number *(cop from Item 1 of Form 1)*	

C. Use the space below to list any of the pollutants listed in Table 2D-3 of the instructions which you know or have reason to believe will be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it will be present.

1. Pollutant	2. Reason for Discharge
	Note that most or all of these pollutants will be removed in the as-yet undefined industrial wastewater treatment process.
Amine (exact type of amine TBD)	***Amines are required for boiler feedwater treatment and coal gasification. Some amount of amine will remain in the HRSG blowdown water and gasification train wastewater.***
Vanadium	***A minimal (10 ug/L) quantity of vanadium may be present due to degradation and corrosion of onsite catalysts and alloys.***
Ammonia	***Ammonia will be used onsite in the SCR used to reduce NOx emissions. Some minimal amount of ammonia may be present in the wastewater, due to leaks.***
Sulfuric Acid, Sodium Hydroxide, Sodium Bisulfite, Sodium Hypochlorite	***All of these substances are likely to be used in the water treatment process. Though unlikely, they may persist in the wastewater in measureable (but minimal) quantities.***

VI. Engineering Report on Wastewater Treatment

A. If there is any technical evaluation concerning your wastewater treatment, including engineering reports or pilot plant studies, check the appropriate box below.

☐ Report Available ☒ No Report

B. Provide the name and location of any existing plant(s) which, to the best of your knowledge, resembles this production facility with respect to production processes, wastewater constituents, or wastewater treatments.

Name	Location
Wabash River Coal Gasification Repowering Project	***West Terre Haute, Indiana***

CONTINUE ON NEXT PAGE

EPA ID Number *(cop from Item 1 of Form 1)*

VII. Other Information *(Optional)*

Use the space below to expand upon any of the above questions or to bring to the attention of the reviewer any other information you feel should be considered in establishing permit limitations for the proposed facility. Attach additional sheets if necessary.

VIII. Certification

I Certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

A. Name and Official Title *(type or print)*	B. Phone No.
Thomas Krueger, Project Manager, Generation Project Development	***(509) 377-4761***
Signature: Thomas W Krueger	D. Date Signed: 8/31/06