Grays Harbor Energy Center

October 30, 2009

Mr. James Luce, Chair
Energy Facility Site Evaluation Council
925 Plum Street SE, Building 4
Olympia, Washington 98504-3172

RE: Satsop Combustion Turbine Project
Submittal of Request for Amendment to Site Certification Agreement

Dear Chair Luce:

With this letter, Grays Harbor Energy LLC, the holder of the Site Certification Agreement (SCA) for the Satsop Combustion Turbine (CT) Project, is requesting an amendment to the SCA. The amendment request includes the following:

1. Changing the name of the project from the Satsop CT Project to the Grays Harbor Energy Center
2. Allowing for the addition of two combustion turbine generators and one steam generator (referred to as Units 3 and 4) to increase the facility capacity by approximately 650 MW to a total of approximately 1,300 MW
3. Enlarging the project site by 10 acres to allow space for construction laydown and access
4. Approval of a PSD permit for Units 3 and 4 (existing PSD permit would remain in place for Units 1 and 2)
5. Increasing the total maximum water usage from existing 9.2 cfs to 16 cfs – no new water authorizations are requested; the additional water would be either purchased or leased from the holder of an existing water right or authorization, such as the Grays Harbor Public Development Authority or the City of Aberdeen.

As proposed, the additional facilities will be located entirely within the boundaries of the existing 22-acre site. The additional 10-acres would be used for construction laydown and access, and would become a permanent part of the project site boundary.

With this amendment request, we have also included a red-line of the existing SCA showing the proposed text revisions.

Submittal

As requested by Allen Fiksdal, we are submitting 30 copies of the amendment request in hard copy and 20 copies in electronic format on CDs.

We would appreciate the opportunity to meet with you and Council staff to provide additional information and to discuss the amendment consideration schedule. We would also like to make a brief presentation to the Council on the project at your November 10 meeting.

Designation of Agent

All official communications concerning this application during the application review process should be directed to Mr. Brett Oakleaf, for Grays Harbor Energy LLC. He is the designated agent for the project and may be contacted as cited below:

Mr. Brett Oakleaf
Director, Business Development
Invenergy LLC
2580 W. Main Street, #200
Littleton, CO 80120
Tel: 303-730-3285
Cel: 303-888-3605
Fax: 303-797-5491
Email: boakleaf@invenergyllc.com

Mr. Steven Bonsma, Invenergy, will serve as a secondary contact. Mr. Bonsma's contact information is as follows:

Mr. Steven Bonsma, Asset Manager
Invenergy LLC
One South Wacker Drive, Suite 1900
Chicago, IL 60606
Tel: 312-582-1538
Fax: 312-224-1444
Email: sbonsma@invenergyllc.com

Local contact is Mr. Todd Gatewood, Plant Manager for Grays Harbor Energy. Mr. Gatewood's contact information is as follows:

Mr. Todd Gatewood, Plant Manager, Grays Harbor Energy
401 Keys Road
Elma, Washington 98541
Tel: 360-482-4353
Mailing Address:
P. O. Box 26
Elma, Washington 98583

Thank you for your consideration of our request.

Sincerely,

Grays Harbor Energy LLC

Mr. Brett Oakleaf
Director, Business Development
Invenergy LLC

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

TABLES

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

FIGURES

CONTENTS (Continued)

LIST OF APPENDICES (INCLUDED ON DISK)

ABBREVIATIONS AND ACRONYMS

ACC	air-cooled direct condenser
ADTV	average daily traffic volumes
AQIA	air quality impact assessment
AQRV	air-quality-related value
ASCE	American Society of Civil Engineers
ASIL	acceptable source impact level
BACT	best available control technology
BMP	best management practices
BPA	Bonneville Power Administration
CARB	California Air Resources Board
CEC	California Energy Commission
CEM	continuous emission monitoring
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFR	Code of Federal Regulations
cfs	cubic feet per second
CO	carbon monoxide
CRGNSA	Columbia River Gorge National Scenic Area
CSZ	Cascadia Subduction Zone
CT	combustion turbine
CTG	combustion turbine generator
D/FD	Duke/Fluor-Daniel
DLN	dry low-NO_x
dB(A)	A-weighted decibel
DNR	Washington State Department of Natural Resources
DWI	driving while impaired
Ecology	Washington State Department of Ecology
EDNA	environmental designation for noise abatement
EFSEC	Energy Facility Site Evaluation Council
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency
EPC	engineering, procurement, and construction
ESA	Endangered Species Act
F	Fahrenheit
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FGR	flue gas recirculation
FIRE	Factor Information Retrieval
FITR	fuel injection timing retard
FLM	federal land manager
FPD	Fire Prevention District
FSAR	Final Safety Analysis Report
g	gravity
GE	General Electric

ABBREVIATIONS AND ACRONYMS (Continued)

GEP	good engineering practice
gpm	gallons per minute
HAL	high-accident location
HCM	Highway Capacity Manual
HCS	highway capacity software
HRSG	heat recovery steam generator
IES	Illuminating Engineering Society
IWQAM	Interagency Workgroup on Air Quality Modeling
K	erodibility factor
kJ	kilojoule
kW-hr	kilowatt-hour
km	kilometer
kV	kilovolt
LAER	lowest achievable emission rate
LCCD	Lewis County Conservation District
L_{eq}	equivalent sound measure
LOS	level of service
M	magnitude
MCE	maximum credible earthquake
MHHW	mean higher high water
MM5	Mesoscale Model
MMBtu	million British thermal units
MSDS	Material Safety Data Sheet
MSL	mean sea level
MV	megavolt
MVA	megavolt (average)
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NDE	non-destructive examination
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NMFS	National Marine Fisheries Service
NOC	Notice of Construction
NOx	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NPSH	net positive suction head
NSPS	New Source Performance Standard
NSR	New Source Review
NWPC	Northwest Pipeline Company
NWS	Northwest Weather Service
OAPCA	Olympic Air Pollution Control Agency
OSHA	Occupational Safety and Health Administration

ABBREVIATIONS AND ACRONYMS (Continued)

PAC	parallel condensing (wet/dry) cooling
PDA	Public Development Authority
PGA	peak ground acceleration
PGU	power generation unit
PHS	Priority Habitat and Species
PM	particulate matter
PMF	probable maximum flood
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million by volume, dry
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gauge
PUD	Public Utility District
PWHT	post-weld heat treatment
QA/QC	quality assurance/quality control
RACT	reasonably achievable control technology
RBLC	RACT/BACT/LAER Clearinghouse
RCP	resource contingency program
RCRA	Resource Conservation and Recovery Act
RCW	Revised Code of Washington
RH	relative humidity
ROW	right-of-way
SCA	Site Certification Agreement
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIL	significant impact level
SNCR	selective non-catalytic reduction
SOC	Species of Concern
SPCC	Spill Prevention Control and Countermeasures
SQER	small quantity emission rate
SR 12	State Route 12
SSC	steam surface condenser
STG	steam turbine generator
SWPPP	Stormwater Pollution Prevention Plan
TAP	toxic air pollutant
T-BACT	best available control technology for toxics
TDML	total maximum daily load
TEFC	totally enclosed fan-cooled
UBC	Uniform Building Code
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UW	University of Washington

ABBREVIATIONS AND ACRONYMS (Continued)

V	volt
VFITR	variable fuel injection timing retard
WAAQS	Washington Ambient Air Quality Standards
WAC	Washington Administrative Code
WARIS	Washington Rivers Information System
WNP-3	Washington Nuclear Project Unit 3
WNP-5	Washington Nuclear Project Unit 5
WPPSS	Washington Public Power Supply System
WRIA	Water Resources Inventory Area
WSDOT	Washington State Department of Transportation

INTRODUCTION

Grays Harbor Energy LLC (the Certificate Holder) is proposing to rename the existing Satsop Combustion Turbine (CT) Project as the Grays Harbor Energy Center, and to increase the facility capacity by approximately 650 megawatts (MW) to a total of approximately 1,300 MW. As with the existing facility, the addition would consist of two gas turbines and one steam turbine in a 2-on-1 configuration that would generate electricity to supply growing regional electrical demand. The new facilities are referred to throughout at Units 3 and 4.

The additional facilities would be constructed on the Grays Harbor Energy Center site. A Site Certification Agreement (SCA) (Application 94-1) was previously approved by the State of Washington. The new facilities would be located entirely within the boundaries of the previously permitted site; however, the site boundary would be enlarged to include 10 acres for construction laydown and access. As a result, the Certificate Holder is applying to the Energy Facility Site Evaluation Council (EFSEC) for an amendment to the existing SCA to allow construction and operation of Units 3 and 4, and to increase the site boundary. This amendment is the fourth amendment to the SCA that was originally issued for the Satsop nuclear power plants.

PROJECT SUMMARY

The addition will consist of two gas turbines and one steam turbine in a 2-on-1 configuration, and have an estimated output of approximately 650 megawatts. The new Units 3 and 4, and will be added to the existing Units 1 and 2.

Units 3 and 4 will be located within the previously permitted site, on land that has already been disturbed and developed for industrial use. The facility will continue to be fueled by natural gas, and no backup fuel source is proposed. The Grays Harbor Energy Center will continue to utilize the natural gas pipeline installed for the existing facility.

Power produced by the Grays Harbor Energy Center will continue to be routed through transmission lines that were installed as part of the original project construction and continue to connect to the Bonneville Power Administration (BPA) system at BPA's Satsop substation. The power will be exported on lines to be installed for Units 3 and 4 on the existing tower structures constructed for Units 1 and 2, from the facility site to the BPA Satsop substation, which is located approximately 4,000 feet east of the site.

EFSEC has already issued an SCA that permitted development of the entire site, and the Council has already considered the impacts associated with site development in connection with permitting the existing facility. As a result, the additional impacts associated with construction and operation of Units 3 and 4 are principally limited to: (1) air emissions, (2) water use and discharge, and (3) sound emissions.

SUMMARY OF ENVIRONMENTAL CONSIDERATIONS

The location and design of Units 3 and 4 incorporate many environmental design features that will eliminate or minimize environmental impacts. The remainder of this section presents a summary of key environmental considerations in the design, construction and operation of Units 3 and 4.

Air

- Units 3 and 4 will utilize the same air emission control technology installed for Units 1 and 2. This technology represents the "state of the art" and consists of General Electric (GE) Frame 7FA combustion turbines in a 2-x-1 combined cycle configuration with a GE D11 steam turbine with dry low-NO_x combustor and selective catalytic reduction (SCR).

- Atmospheric emissions will be in compliance with all applicable federal and state air quality regulations.

- Each combustion turbine unit will incorporate best available control technologies (BACT).

- Air emissions and the resulting effect on ambient air quality are addressed in Sections 2.11, 3.2 and 5.1 of the application.

Water Use and Discharge

- Water for cooling will be obtained through the existing Ranney wells, and delivered through water lines originally constructed for the Satsop nuclear plants.

- Like the existing Units 1 and 2, Units 3 and 4 will utilize a mechanical draft (wet) cooling system. Maximum water needs will not exceed 16 cfs for the operation of the existing two units and the proposed additional two units.

- Additional water will be obtained from the holder of an existing water right or authorization, such as the Grays Harbor Public Development Authority or the City of Aberdeen. No new water rights or authorizations will be required.

- Water discharge from expanded facility will be governed by the facility's National Pollutant Discharge Elimination System (NPDES) permit and will meet the state's applicable acute and chronic water quality criteria for Class A waters for discharge to the Chehalis River.

- The requirements of the Erosion and Sediment Control Plan (approved by EFESEC on November 1, 2005) will apply to the construction and operation of the additional units as well. This plan was implemented to protect water quality with the start of the original construction, and will minimize erosion, sedimentation, and contaminated runoff. During construction and operation, the Certificate Holder and its contractors will adhere to the procedures, methods and other requirements presented in this plan.

- Water use and water quality issues are addressed in Sections 2.5, 2.8 and 3.3 of the application.

Noise

- Units 3 and 4 are being designed to ensure that its operation will comply with EFSEC noise regulations and will not result in significant changes in noise levels at nearby industrial areas or residences.

- Sound attenuation has been included in the design of Units 3 and 4 through the proper selection of materials and equipment, as well as in the overall layout of the plant.

- The sound emissions from the expanded project and the proposed noise mitigation measures are addressed in Section 4.1 of the application.

Plants and Animals

- Units 3 and 4 will fit entirely within the previously permitted and developed Grays Harbor Energy Center site. Construction of Units 3 and 4 on a disturbed and developed site will minimize impacts to vegetation and wildlife. The existing site does not contain vegetation, wetlands or open water.

- The 10-acre site proposed for construction laydown and access is designated in the Satsop Development Park Master Plan for industrial development. It contains approximately 5 acres of forest and 5 acres of grassland that is mowed every year. The forested area is separated from other forested land within the Satsop Development Park by roadways, the BPA right-of-way or existing development. There are no wetlands or open water within the 10 acres, and the impacts to wildlife from the loss of this habitat have been considered to be minor, and less than significant. (See Section 3.4 Plants and Animals)

- Units 3 and 4 will utilize the natural gas pipeline that was installed for Units 1 and 2, and the existing water supply line and discharge that were originally built for the Satsop nuclear power plants and utilized by Units 1 and 2. Power generated by the Units 3 and 4 will be delivered to BPA's existing high-voltage transmission system at the Satsop 230 kilovolts (kV) substation. The power will be exported on lines to be installed for Units 3 and 4 on the existing tower structures constructed for Units 1 and 2, from the facility site to the BPA Satsop substation, which is located approximately 4,000 feet east of the site. The use of existing utilities avoids impacts to plants and animals that would otherwise result from the creation of new utility corridors.

Land Use, Cultural Resources and Recreation

- The expanded project complies with Grays Harbor County's current land use plan and zoning ordinance. The site is zoned for industrial use and is designated Industrial 2 (I-2).

- The use of the site for industrial use is consistent with Grays Harbor Public Development Authority's planned use of the surrounding Satsop Development Park.

- Cultural resource surveys were conducted prior to the original development of the site. The construction and operation of the expanded project will not impact cultural resources.

Visual Resources

- The Grays Harbor Energy Center will continue to be consistent with the visual character of the surrounding area. Units 3 and 4 will be constructed immediately adjacent to the permitted Units 1 and 2 and will be surrounded by industrial and commercial development in the Satsop Development Park.

- There are few residents near the plant site, with the nearest residents located more than 2,000 feet west of the site. A 25-foot-high noise wall with a 12-foot-high landscaped berm on the street side was constructed as part of the initial development along Keys Road. Units 3 and 4 will be located further to the east, behind Units 1 and 2. The berm and noise wall will screen both phases of the project from travelers along Keys Road and will screen portions of the facilities from the views of nearby residents.

- Topography and vegetation obstruct views of the site from more distant locations. The 180-foot emission stacks for Units 3 and 4 will be approximately one-third the height of the existing cooling towers constructed for the Satsop nuclear project. The nuclear project stacks, at 496 feet, will remain the dominant landmark in the area. A computer simulation of the expanded project silhouette provided in Section 4.2 indicates that Units 3 and 4 will not be visible from prominent viewpoints, such as along State Route 12 or from residences in the Chehalis River Valley.

Socioeconomics and Public Services

- The construction of Units 3 and 4 will extend the positive economic benefits of both jobs and income to the local economy. Construction jobs will peak at approximately 540 jobs for a period of 4 months.

- Like the existing facility, operation of the expanded facility will have positive impacts in terms of jobs, taxes, and purchase of goods and services.

- The proposed addition of Units 3 and 4 to the Grays Harbor Energy Center will have minor impacts on existing public services.

Transportation

- During construction, delays at the intersection of Keys Road and State Route 12 during the evening commuting period are possible. A traffic and transportation plan for construction, in accordance with a Grays Harbor County Public Works Division letter dated July 2, 2001, was approved by EFSEC on September 19, 2001. This plan will be applicable to the construction period for Units 3 and 4.

- During operation of the Grays Harbor Energy Center, an additional 8 people will be employed and a maximum of 31 employees will be on site at any time. Negative impacts on transportation during normal operation are unlikely.

1.0 GENERAL

SECTION 1.1 DESCRIPTION OF APPLICANT (WAC 463-60-015)

1.1.1 PURPOSE OF AMENDMENT

This is an application for an amendment to the existing Satsop Combustion Turbine Project Site Certification Agreement (SCA). The amendment, if approved, would change the name of the project from the Satsop Combustion Turbine Project to Grays Harbor Energy Center, and would allow the addition of two combustion turbine units to the Grays Harbor Energy Center to increase capacity by approximately 650 megawatts (MW), doubling its maximum annual capacity to approximately 1,300 MW.

1.1.2 APPLICANT

The applicant for this SCA amendment is the current Certificate Holder, Grays Harbor Energy LLC, a subsidiary of Invenergy LLC (Invenergy).

This application was professionally prepared by URS Corporation and ENVIRON under the direction of Grays Harbor Energy LLC. These parties believe that the application is substantially complete and meets the requirements established in Chapter 80.50 of the Revised Code of Washington (RCW) and Title 463 of the Washington Administrative Code (WAC).

1.1.3 GRAYS HARBOR ENERGY LLC

Grays Harbor Energy LLC will continue to own the Grays Harbor Energy Center.

1.1.4 INVENERGY LLC

Invenergy is a developer, owner and operator of power generation facilities with the organizational, financial, managerial, and technical capability to comply with the terms of the SCA. Invenergy currently owns, operates or has under development energy facilities (i.e., natural gas, wind and solar) with a combined capacity of more than 5,000 MW, and is actively evaluating other projects for acquisition and development.

Invenergy has an experienced management team with a track record of success in developing, owning and operating more than 12,000 MW of power generation projects. The members of the management team have an average experience of approximately 20 years in diverse areas of the energy market including development, engineering, construction, finance, operations, asset management, and energy trading and contracting.

SECTION 1.2 DESIGNATION OF AGENT (WAC 463-60-025)

All official communications concerning this application during the application review process should be directed to Mr. Brett Oakleaf, for Grays Harbor Energy LLC. He is the designated agent for the project and may be contacted as cited below:

Mr. Brett Oakleaf
Director, Business Development
Invenergy LLC
2580 W. Main Street, #200
Littleton, CO 80120
Tel: 303-730-3285
Cel: 303-888-3605
Fax: 303-797-5491
Email: boakleaf@invenergyllc.com

Mr. Steven Bonsma, Invenergy, will serve as a secondary contact. Mr. Bonsma's contact information is as follows:

Mr. Steven Bonsma, Asset Manager
Invenergy LLC
One South Wacker Drive, Suite 1900
Chicago, IL 60606
Tel: 312-582-1538
Fax: 312-224-1444
Email: sbonsma@invenergyllc.com

Local contact is Mr. Todd Gatewood, Plant Manager for Grays Harbor Energy. Mr. Gatewood's contact information is as follows:

Mr. Todd Gatewood, Plant Manager, Grays Harbor Energy
401 Keys Road
Elma, Washington 98541
Tel: 360-482-4353

Mailing Address:
P. O. Box 26
Elma, Washington 98583

SECTION 1.3 ASSURANCES (WAC 463-60-075)

Grays Harbor Energy LLC, the Certificate Holder, is proposing to expand the Grays Harbor Energy Center at the site already approved through an SCA. As with the existing Grays Harbor Energy Center, the Certificate Holder will establish and maintain several forms of insurance during construction and operation of the expanded facility as are required by law, customary business practice, or third-party participants such as lenders. The following coverages will be included:

- ***Comprehensive General Public Liability* –** The Certificate Holder will carry Comprehensive General Public Liability insurance including coverage for bodily injury (including death), property damage, independent contractors, products, and completed operations with a limit of liability of $1 million per occurrence and a $2 million aggregate limit
- ***Employer's Liability* –** The Certificate Holder will carry Employer's Liability insurance with a limit of liability of $1 million per occurrence
- ***Comprehensive Automobile Liability* –** The Certificate Holder will carry Comprehensive Automobile Liability insurance including coverage for all owned, hired, or non-owned automobiles with a limit of liability of $1 million per occurrence
- ***Workers Compensation* –** The Certificate Holder will carry Worker's Compensation and other insurance as required by law for all employees of the Grays Harbor Energy Center
- ***Pollution Liability* –** The Certificate Holder will carry pollution liability insurance with a limit of $5 million
- ***Umbrella and Excess Liability* –** The Certificate Holder will carry umbrella and excess liability over and above comprehensive general public, employer’s, and comprehensive automobile liabilities with occurrence and aggregate limits of $50 million

SECTION 1.4 MITIGATION MEASURES (WAC 463-60-085)

Units 3 and 4 will be located within the previously permitted site, on land that has already been disturbed and developed for industrial use. The project will continue to be fueled by natural gas, and no backup fuel source is proposed. The Grays Harbor Energy Center will continue to utilize the natural gas pipeline installed for the existing facility.

Power produced by the Grays Harbor Energy Center will continue to be routed through transmission lines that were installed as part of the original project construction and continue to connect to the Bonneville Power Administration (BPA) system at BPA's Satsop substation. The power will be exported on lines to be installed for Units 3 and 4 on the existing tower structures constructed for Units 1 and 2, from the project site to the BPA Satsop substation, which is located approximately 4,000 feet east of the project site.

EFSEC has already issued an SCA that permitted development of the entire site, and the Council has already considered the impacts associated with site development in connection with permitting the existing facility. As a result, the additional impacts associated with construction and operation of the two additional units are principally limited to: (1) air emissions, (2) water use and discharge, and (3) sound emissions.

By locating Units 3 and 4 within the area already developed for Units 1 and 2, most impacts have been eliminated. The following is a summary of the additional mitigation measures that are proposed to either eliminate or minimize environmental impacts.

1.4.1 SECTION 3.2, AIR

To control dust during construction, water would be applied as necessary, access roads would be graveled or paved.

BACT would be incorporated into the Units 3 and 4 design to reduce air pollution emissions.

Greenhouse gas emissions would be mitigated pursuant to RCW chapter 80.70. Grays Harbor Energy LLC has chosen the "monetary path" outlined in RCW 80.70.020(5) for mitigation. At the current rate of $1.60 per metric ton of carbon dioxide, the required payment is approximately $11.75 million. Grays Harbor Energy LLC currently plans to provide EFSEC with proof of payment to a qualifying organization of the total sum, no later than one hundred twenty days after the start of commercial operation.

1.4.2 SECTION 3.3, WATER

Surface Water

To minimize impacts on surface water, contractors will use Best Management Practices (BMPs) for erosion and sediment control during construction of Units 3 and 4 and will implement a plan that complies with the requirements of the existing Erosion and Sedimentation Control Plan. BMPs will include limiting certain construction activities and installing temporary control structures such as sediment traps, silt fences, and diversion ditches.

To meet the temperature requirements of the discharge, heat exchangers will be used to control the temperature of the cooling water discharge.

Groundwater

Process water is discharged via a diffuser to the Chehalis River, and stormwater is directed to the C-1 pond for treatment and discharged via surface drainage to the Chehalis River. Sanitary waste is discharged to a septic system. The placement and design of the system allows infiltration of effluent but inhibits its direct release to surface and/or groundwater bodies.

Additionally, the project is situated on terrace deposits with smaller, discontinuous perched aquifers and the site is built on gravel fill, which is underlain by a liner that restricts water infiltration. As a result, plant construction will not have an impact on groundwater quality. Therefore, no significant impacts to groundwater quantity or quality are likely to occur.

1.4.3 SECTION 4.1, ENVIRONMENTAL HEALTH

Noise

The proposed acoustical design of Units 3 and 4 will include silencers placed within the air intake ductwork of the combustion turbines to reduce high-frequency compressor and turbine blade noise levels. In addition, acoustical enclosures will reduce casing radiated noise from the combustion turbines, steam turbines and other auxiliary support equipment. Turbine exhaust noise will be attenuated via the heat recovery steam generators (HRSGs) as well as by absorptive silencers placed either in the HRSG ductwork leading to the stacks or hung within the stacks themselves.

Moreover, the proposed expansion will take advantage of the existing acoustical barriers along the northern and western property boundaries. If necessary, additional acoustical barriers may be erected along the northern and southern property boundary to control property line noise levels (see conceptual barrier layout in Figure 4.1-4). Specifically, noise level measurements would be collected during performance testing (prior to commercial operation) and used to determine whether acoustical barriers are necessary, and if so, the optimal height, length and placement of any barriers.

Acoustical modeling indicates that based on this design, noise levels from the Grays Harbor Energy Center are expected to fully comply with applicable limits at residential receivers and adjacent industrial properties. The precise details and extent of any noise control measures needed for the plant will be refined, if necessary, during the detailed engineering phase of Units 3 and 4, at a time when additional noise level data can be obtained from vendors, and when additional design details have been completed.

Risk of Fire or Explosion

The risk of an explosion in the Grays Harbor Energy Center will be mitigated by designing, constructing, and operating the facility as required in the latest versions of the applicable codes, regulations, and consensus standards.

As with the existing Grays Harbor Energy Center, the facility will continue to be operated by qualified personnel using written procedures. Procedures provide clear instructions for safely conducting activities involved in the initial startup, normal operations, temporary operations, normal shutdowns, emergency shutdowns, and subsequent startups. The procedures for emergency shutdowns include the conditions under which emergency shutdowns are required, and the assignment of shutdown responsibilities to qualified operators to ensure that shutdowns are done in a safe and timely manner. Also covered in the procedures are the consequences of operational deviations and the steps required to correct or avoid the deviations.

Before being involved in operating the facility, employees will be presented with a facility plan, including a Health and Safety Plan, and will receive training regarding the operating procedures and other requirements of safe operation of the plant. In addition, employees will receive annual refresher training, which will include testing of their understanding of the procedures. Training and testing records will be maintained.

The existing hazardous materials emergency response program will continue to be used. Grays Harbor Energy emergency responders trained and equipped to the technician level will be available at all times when the facility is in operation. The emergency responders will use a written emergency response plan developed for the Grays Harbor Energy Center and revised, if needed, to include the addition of Units 3 and 4.

1.4.4 SECTION 4.2, LAND AND SHORELINE USE

Light and Glare

In specific locations where glare or light spillover could impact Keys Road or be obtrusive to nearby residences, lighting angles could be adjusted to minimize glare impacts, or supplemental light shields/vegetation could be used for extra screening.

Aesthetics

Equipment enclosure buildings and exterior tanks would be painted earth-tone beige and gray to reduce contrasts. The emission stacks would be painted to blend with the sky as seen from distant viewpoints.

1.4.5 SECTION 4.3, TRANSPORTATION

Vehicular traffic during construction of the Units 3 and 4 will cause a degradation in the level of service (LOS) at the intersection of SR 12 and Keys Road during the afternoon/pm peak hour.

Prior to construction of the Grays Harbor Energy Center, a traffic management plan was submitted to EFSEC for review and was approved. This EFSEC-approved plan will also apply to construction of Units 3 and 4. The main component of the traffic management plan included a recommendation to encourage the use of the Wakefield/Lambert corridor for site access and egress. It is recommended that vehicles traveling to/from the facility site during construction of Units 3 and 4, and operation of the Grays Harbor Energy Center, use the Wakefield/Lambert corridor primarily, and avoid the intersection of SR 12 and Keys Road.

SECTION 1.5 SOURCES OF INFORMATION (WAC 463-60-095)

Baker, C.F. 2008. *Seasonal Floodplain Wetlands as Fish Habitat in Oregon and Washington*. PhD Thesis, Oregon State University, Corvallis, Oregon.

Bolt, Beranek, and Newman, Inc. 1997. Power Plant Construction Noise Guide. May.

Brenkman, S.J. and S.C. Corbett. 2005. “Extent of Anadromy in Bull Trout and Implications for Conservation of a Threatened Species.” *North American Journal of Fisheries Management* 25:1073-1081.

Brenkman, S.J., S.C. Corbett, and E.C. Volk. 2007. “Use of Otolith Chemistry and Radiotelemetry to Determine Age-Specific Migratory Patterns of Anadromous Bull Trout in the Hoh River, Washington.” *Transactions of the American Fisheries Society* 136:1-11.

Brown, Chris. City of Elma Fire Marshall. Telephone communication with Katie McKinstry, URS Corporation. November 1, 2001.

Chehalis Basin Partnership. 2003. Supplement to the Chehalis basin level 1 assessment: documentation of existing water quality conditions, monitoring activities and TMDLs. Prepared by Tetra Tech/KCM, Inc in association with Triangle Associates.

Crass, Steve. Interim Chief, Montesane Fire Department. Telephone communication with Katie McKinstry, URS Corporation. October 31, 2001.

CTED – see Washington State Department of Community, Trade and Economic Development

Dames & Moore. 1994. Phase I Environmental Site Assessment. April.

DeRidder, N. Westinghouse Electric Corporation, Generation Systems Divisions, Orlando, Florida. Personal communication and fax transmission. March 16, 1995.

Dvornich, K.M., K.R. McAllister, and K.B. Aubry. 1997. *Amphibians and Reptiles of Washington State; Location Data and Predicted Distributions.* Vol. 2 in *Washington State GAP Analysis - Final Report*, K.M. Cassidy, C.E. Grue, M.R. Smith, and K.M. Dvornich, eds. Washington Cooperative Fish and Wildlife Research Unit, University of Washington, Seattle.

Ecology – see Washington State Department of Ecology

Energy Facility Site Evaluation Council (EFSEC). 2008. National Pollutant Discharge Elimination System Waste Discharge (NPDES) Permit WA-002496-1. Satsop Combustion Turbine Project. May 13.

Energy Facility Site Evaluation Council and Bonneville Power Administration (EFSEC/BPA). 2004. Final Environmental Impact Statement: BP Cherry Point Cogeneration Project. August. Accessed at: http://www.efsec.wa.gov/bpcogen/FEIS/vol1/%208%20-%203%20.2%20Air.pdf.

ENVIRON. 2009. Modeling Protocol in Support of a Combined Notice of Construction and PSD Permit Application for the Installation of Two Power Generation Units Modifying an Existing Stationary Source. Prepared for Grays Harbor Energy LLC, Elma, WA. May. Project No. 29-22706A.

Envirosphere Company (Envirosphere). 1982. Metals Monitoring Program, November 1980 – October 1981, Washington Public Power Supply System, Nuclear Projects 3 and 5, Final Report. March.

Federal Land Managers' Air Quality Related Values Workgroup (FLAG). 2000. Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). Accessed at: http://www.fs.fed.us/r6/aq/natarm/NRISFLAG.html.

Franklin, J.F., and C.T. Dyrness. 1988. *Natural Vegetation of Oregon and Washington.* Oregon State University Press. Corvallis, Oregon.

Grays Harbor Economic Development Council. 2009. Grays Harbor County Demographic Profile. May. Accessed at: http://www.ghedc.com/downloads/GHEDC_DemoProfile.pdf.

Graw, Rick. US Forest Service. Letter to Ken Richmond, Environ, entitled “Grays Harbor Energy Phase 2 Class I Area Modeling Protocol.” July 18, 2008.

———. US Forest Service. Letter to Jim La Spina, EFSEC, entitled “Grays Harbor Energy Modeling Protocol Comments.” May 14, 2009.

Henning, J. 2004. An Evaluation of Fish and Amphibian Use of Restored and Natural Floodplain Wetlands. Prepared by Washington State Department of Fish and Wildlife, Montesane, Washington for EPA, Region 10, Seattle, Washington.

Interagency Workgroup on Air Quality Modeling (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. December.

Jeanes, E.D., C.M. Morello, and M.H. Appy. 2003. Native Char Utilization, Lower Chehalis River and Grays Harbor Estuary, Aberdeen, Washington. Prepared by R2 Resource Consultants, Inc., for US Army Corps of Engineers, Seattle District.

Johnson, R.E. and K.M. Cassidy. 1997. *Terrestrial Mammals of Washington State; Location Data and Predicted Distributions.* Vol. 3 in *Washington State GAP Analysis - Final Report*, K.M. Cassidy, C.E. Grue, M.R. Smith, and K.M. Dvornich, eds. Washington Cooperative Fish and Wildlife Research Unit, University of Washington, Seattle.

Jones, Jean. Grays Harbor Emergency Medical Services and Trauma Care Council, Inc. Personal Communication to Katie McKinstry, URS Corporation. October 31, 2001.

Kelley, M. 1997. The “Other Fishes” of the Chehalis River. Chehalis River Council, Centralia, Washington.

Lewis County Conservation District (LCCD). 1992a. Chehalis River Basin Action Plan. Chehalis, Washington.

———. 1992b. Chehalis River Basin Action Plan, Technical Supplement. Chehalis, Washington. October.

McPhail, J.D. 1969. "Distribution of Freshwater Fishes of Western Washington." *Northwest Science* 41(1):1-11.

MFG, Inc. 2003. Grays Harbor Energy Facility, Satsop, Washington, Ambient Air and Meteorological Monitoring Annual Data Report, May 2002 through May 2003.

Mongillo, P. and M. Hallock. 1995. Resident Nongame Fish Investigations 1993-1994 Report. Washington Department of Fish and Wildlife, Olympia, Washington.

———. 1997. Distribution and Habitat of Native Nongame Stream Fishes of the Olympic Peninsula. Washington Department of Fish and Wildlife, Olympia, Washington.

———. 1999. Washington State Status Report for the Olympic Mudminnow. Washington Department of Fish and Wildlife, Olympia, Washington.

Morse, Dee. National Park Service. Email to Jim LaSpina, EFSEC, entitled "June 16, 2009 Grays Harbor Energy Modeling Supplemental Protocol. – NPS Comments." June 18, 2009.

Moser, M.L. and S.T. Lindley. 2007. "Use of Washington Estuaries by Subadult and Adult Green Sturgeon." *Environmental Biology of Fishes* 79:243-253.

National Marine Fisheries Service (NMFS). 2008. Endangered Species Act Status of West Coast Salmon & Steelhead. Accessed at: www.nwr.noaa.gov/ESA-Salmon-Listings/Salmon-Populations/Index.cfm.

Notar, John. National Park Service. Email to Jim La Spina, EFSEC, entitled "Re: Status of June 16, 2009 Grays Harbor Energy Modeling Supplemental Protocol." July 8, 2009.

Parametrix. 1993. Combustion Turbine Draft Environmental Impact Statement. Prepared for Seattle City Light.

Peterson, J., D.L. Schmoldt, D. Peterson, J. Eilers, R. Fisher, and R. Bachman (Peterson et al.). 1992. Guidelines for Evaluating Air Pollution Impacts on Class I Areas in the Pacific Northwest. USDA Forest Service, General Technical Report PNW-GTR-299. May.

Seiler, D. 1989. "Differential Survival of Grays Harbor Basin Anadromous Salmonids: Water Quality Implications." In *Proceedings of the National Workshop on Effects of Habitat Alteration on Salmonid Stocks*, C.D. Levings, L.B. Holtby, and M.A. Henderson, eds. Canadian Special Publication of Fisheries and Aquatic Sciences 105: 123–135.

Smith, C.J. and M. Wenger. 2001. Salmon and Steelhead Habitat Limiting Factors, Chehalis Basin and Nearby Drainages, Water Resource Inventory Areas 22 and 23. Washington State Conservation Commission, Lacey, Washington.

Smith, M.R., P.W. Mattocks, Jr., and K.M. Cassidy, K.M. 1997. Breeding Birds of Washington State. Volume 4 in *Washington State Gap Analysis – Final Report.* K.M. Cassidy, C.E. Grue, M. R. Smith, and K.M. Dvornick, eds. Seattle Audubon Society Publications in *Zoology* 1. Seattle.

Thompson, Nancy. Washington State Department of Transportation, Olympia. Personal communication with Claire Hoffman, URS Corporation. July 14, 2008.

Transportation Research Board (TRB). 2000. *Highway Capacity Manual.* National Research Council, Washington, D.C.

United States Department of Agriculture Soil Conservation Service (USDA SCS). 1986. *Soil Survey of Grays Harbor County Area, Pacific County, and Wakiakum County, Washington.*

United States Environmental Protection Agency (USEPA). 2009. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007, Executive Summary. April 15. Accessed at: http://www.epa.gov/climatechange/emissions/usinventoryreport.html.

United States Environmental Protection Agency, National Park Service and Fish and Wildlife Service (UESPA et al.) 2009. Reassessment of the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report: Revisions to Phase 2 Recommendations. Office of Air Quality Planning and Standards, Research Triangle Park, NC. EPA-454/R-09-XXX, May 27.

United States Fish and Wildlife Service (USFWS). 2004. Draft Recovery Plan for the Coastal-Puget Sound Distinct Population Segment of Bull Trout (Salvelinus confluentus), Volume II (of II), Olympic Peninsula Management Unit. USFWS Region 1, Portland, Oregon.

———. 2008. Grays Harbor Species List. Accessed at: www.fws.gov/westwafwo/speciesmap/GRAYS%20HARBOR.html.

United States Forest Service, National Park Service, and United States Fish and Wildlife Service (USFS et al.). 2008. Draft Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report – Revised. June 27, 2008. Accessed at: http://www.nature.nps.gov/air/permits/flag/index.cfm.

United States Geological Survey (USGS). 1999. Water resources data, Washington, water year 1999. US Department of the Interior, Tacoma, Washington.

URS Corporation. 2001. Report of Geotechnical Investigation, Grays Harbor Power Project, Satsop, Washington. Prepared for Duke/Fluor-Daniel. June 8.

Wahl, T.R., B. Tweit, and S.G. Mlodinow. 2005. *Birds of Washington, Status and Distribution*. Oregon State University Press, Corvallis, Oregon.

Washington Department of Fish and Wildlife (WDFW). 2000. Washington Salmonid Stock Inventory (SaSI), Coastal Cutthroat Trout. Olympia, Washington.

———. 2002. Washington State Salmonid Stock Inventory. Accessed at: www.wdfw.wa.gov/fish/sasi.

———. 2004. Washington State Salmonid Stock Inventory, Bull Trout/Dolly Varden. Olympia, Washington.

———. 2008a. Species of Concern and Priority Habitat and Species website. Accessed at: wdfw.wa.gov/wildlife/management/endangered.html.

———. 2008b. *Priority Habitats and Species List.* Wildlife Management Program. June 19.

———. 2008c. SalmonScape website. Accessed at: www.wdfw.wa.gov/mapping/salmonscape/index.html.

Washington Department of Fisheries (WDF). 1971. *Angling for Salmon, Shad and Sturgeon in Freshwaters of Washington State*. Olympia, Washington.

———. 1975. *A Catalog of Washington Streams and Salmon Utilization, Volumes 1 and 2: Coastal Region.* R.W. Williams, ed. Olympia, Washington.

———. 1992. Results of the Grays Harbor Coho Survival Investigations, 1987-1990. *Technical Report* Number 118. S. Schroder and K. Fresh, eds. Olympia, Washington.

Washington Department of Wildlife (WDW). 1992. *1992 Washington State Salmon and Steelhead Stock (SASSI) Inventory*. Olympia, Washington.

Washington Office of Superintendent of Public Instruction (WOSPI). 2008. Total Enrollment, Gender and Ethnicity. School Year 2007-2008. October. Accessed at: http://www.k12.wa.us/DataAdmin/pubdocs/p105/Oct08BldgLevEnrollment.xls.

Washington Public Power Supply System (WPPSS). 1982. Environmental Report – Operating License Stage (ER – OL). December.

———. 1984. Final Safety Analysis Report (FSAR).

Washington State Department of Community, Trade and Economic Development (CTED). 2007. Washington's Greenhouse Gas Emissions: Sources and Trends. Revised February 12. Accessed at: http://www.cted.wa.gov/site/853/default.aspx.

Washington State Department of Ecology (Ecology). 2005. *Stormwater Management Manual for Western Washington.* No. 05-10-029. April. Accessed at: http://www.ecy.wa.gov/programs/wq/stormwater/manual.html.

Washington State Department of Transportation (WSDOT). 2006. *2006 Annual Traffic Report.*

———. 2008. Biological Assessment Preparation for Transportation Projects, Advanced Training Manual. Lacey, Washington.

Washington State Office of Financial Management (WSOFM). 2001a. *Washington State Office of Financial Management, 2000 Census Data, Washington's Census 2000 Demographic Profile.* Accessed at: http://www.ofm.wa.gov/census2000/stf1/dp1.xls.

———. 2001b. *Table DP-1. Profile of General Demographic Characteristics for Washington: 2000.* Accessed at: http://www.census.gov/Press-Release/www/2001/tables/dp_wa_2000.PDF.

———. 2009. *Washington State Office of Financial Management 2009 Population Trends.* Accessed at: *http://www.ofm.wa.gov/pop/poptrends/poptrends.pdf.*

Welker, T. 1993. Letter report and spotted owl survey forms for the Homer Hill survey area. Washington Department of Natural Resources, Chehalis, Washington.

Wilder, Tom. Grays Harbor County Fire Protection District No. 5. 2001. Telephone communication with Katie McKinstry, URS Corporation. November 8, 2001.

Willis, Larry. Brady Station Chief, Grays Harbor County Fire Protection District No. 2. Telephone communication with Katie McKinstry, URS Corporation. October 31, 2001.

Wydoski, R.S., and R.R. Whitney. 2003. *Inland Fishes of Washington, Second Edition, Revised and Expanded.* University of Washington Press. Seattle, Washington.

Zahn, M. Wildlife biologist, Washington Department of Wildlife, Elma, Washington. Personal communication. 2001.

2.0 PROPOSAL

SECTION 2.1 SITE DESCRIPTION (WAC 463-60-125)

2.1.1 PROJECT SUMMARY

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

Units 3 and 4 would be constructed entirely within the boundaries of the approximately 22-acre Satsop Combustion Turbine (Grays Harbor Energy Center) project site, for which the State of Washington has already approved an SCA. A 10-acre site immediately east of the project site would be used for construction laydown and access and would become part of the overall site boundary. The fuel will be natural gas only, and will be supplied by an existing pipeline that was constructed as part of the initial site development.

As a part of the construction for the original Grays Harbor Energy Center, transmission lines were installed in the Bonneville Power Administration (BPA) right-of-way from the site to the substation. Power produced by Units 3 and 4 will be transmitted on new lines installed on the existing tower structures that connect to the BPA system at BPA's Satsop substation, approximately 4,000 feet east of the project site.

2.1.2 PROJECT LOCATION

2.1.2.1 Plant Site

The site is located south of the Chehalis River near the town of Elma (Figure 2.1-1). The 1,600-acre Satsop Development Park surrounds the site on all four sides. The site is located approximately 0.5 mile southwest of the river. Fuller Creek is approximately 0.5 mile to the east, and Workman Creek is located approximately 2 miles to the east.

In 1994, Energy Northwest submitted an application to build the Satsop Combustion Turbine Project on this 22-acre site. The 22-acre site was part of the much larger site that had been subject of an SCA issued in 1976 that authorized construction and operation of a nuclear facility. The 22-acre combustion turbine site was thoroughly evaluated by the Energy Facility Site Evaluation Council (EFSEC) and in an environmental impact statement was published by BPA. In 1996, EFSEC amended the SCA to allow a natural-gas fired combustion turbine facility to be constructed on the 22-acre site. The project later changed ownership and was redesigned so that the original facility, now known as the Grays Harbor Energy Center, could be built on only approximately 12 acres of the site, leaving room for future plant additions on the previously studied and permitted site. EFSEC amended the SCA in 2001 to reflect these changes.

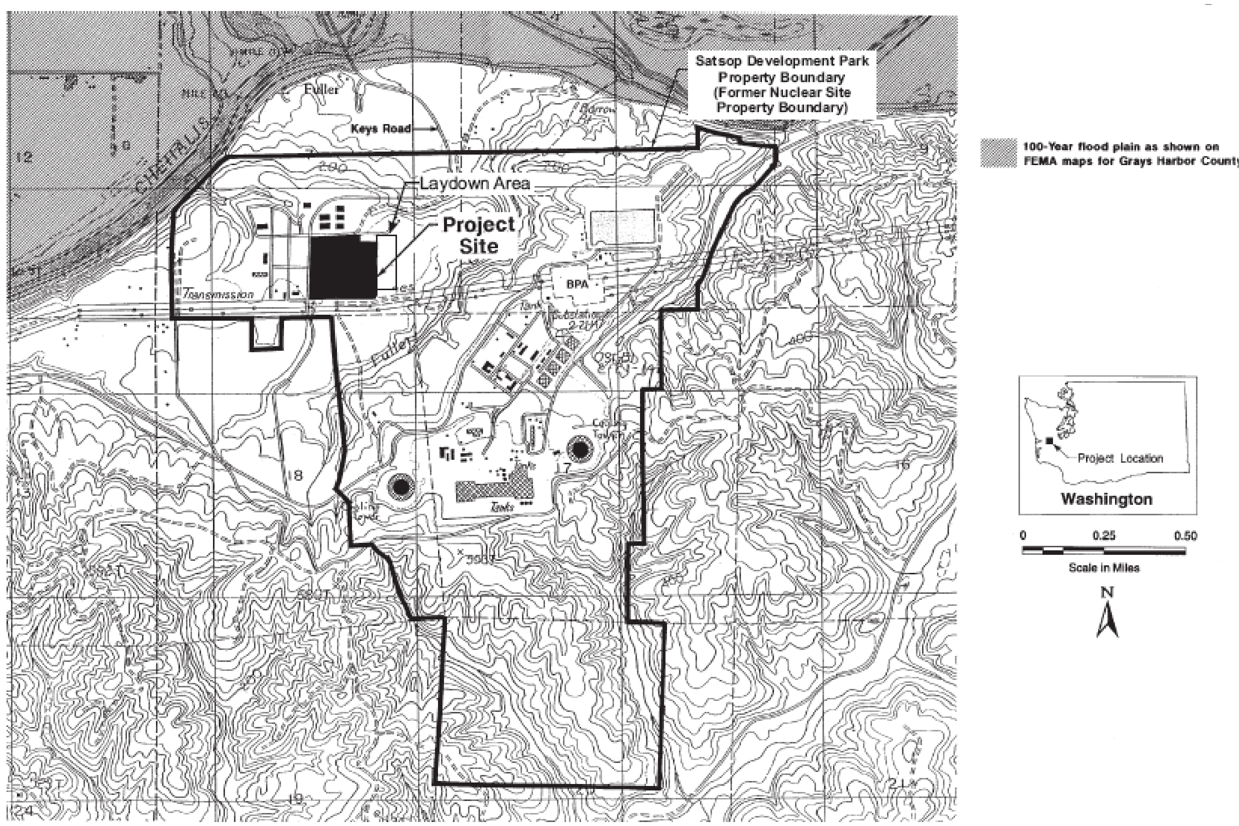


Figure 2.1-1
Project Location

Construction of the Grays Harbor Energy Center was completed in the second quarter of 2008 and commercial operation began April 25, 2008. To the north and northwest of the site are various field offices, storage buildings, and stockpiled building materials. Similar items and facilities are located west of Keys Road. To the south is the BPA transmission line right-of-way. To the east of the site is an approximately 10-acre strip of land that is proposed to be cleared for construction laydown and access. A raw water tank and pump house, owned and operated by the Grays Harbor Public Development Authority (PDA), are located in the northeast corner of the site (Figure 2.1-2). As part of the construction of the Grays Harbor Energy Center, the entire 22-acre site was cleared of structures, discarded construction materials, and unneeded utilities.

The only additional clearing required for construction of Units 3 and 4 would be the approximately 10-acre parcel proposed for construction laydown and access, which is located immediately east of the site. The 10-acre site currently consists of approximately 5 acres of thinned conifers and 5 acres of grassland/agriculture that is mowed every year.

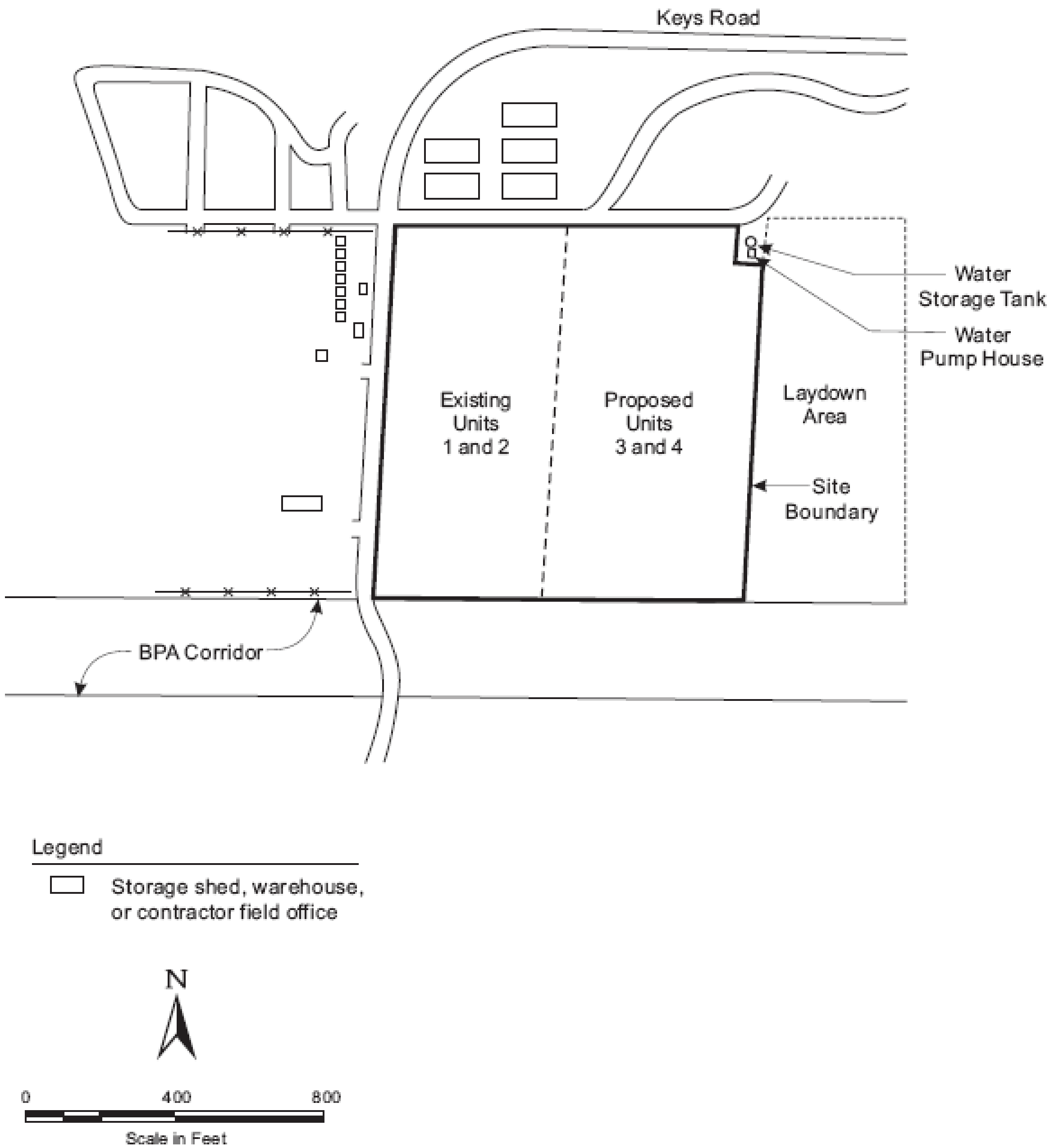


Figure 2.1-2
Project Site

2.1.3 ZONING ORDINANCES

The plant site is located in unincorporated Grays Harbor County near the town of Elma and surrounded by the property boundary of the Satsop Development Park (Figure 2.1-1).

The plant site is located in areas zoned as Industrial District 2, or I-2, under Grays Harbor County Comprehensive Zoning Ordinance No. 241 (Title 17). According to Grays Harbor

Zoning Ordinance 17.52.010), *"The purpose and intent of the industrial district is to provide areas where industrial activities and uses involving the processing, fabrication and storage of products may be located. The district also allows such commercial uses that serve primarily the industrial district."* Uses permitted outright include industrial uses and industrial development facilities as defined by RCW 39.84.020 Part 6. Energy facilities are included within this definition.

In passing the rezone at a Grays Harbor Planning Commission meeting on November 2, 1998, the Planning Commission found that the utilization of the infrastructure originally built for the Satsop Nuclear Plant and the reuse of existing sites for industrial purposes will promote job creation and economic diversification, expressed purposes of the Grays Harbor County Comprehensive Plan.

In connection with the application for the original Grays Harbor Energy Center, EFSEC found that the project was *"consistent with applicable land use laws and regulations"* (EFSEC Order No. 694 *as modified,* April 15, 1996). In 2002, the Council considered an application for an expansion of the Satsop CT Project that was very similar to the current proposal for the additional two units, and EFSEC found that the proposed project *"is consistent and in compliance with Grays Harbor County and regional land use plans and zoning ordinances"* (EFSEC Order No. 766, March 27, 2002).

SECTION 2.2 LEGAL DESCRIPTION AND OWNERSHIP INTERESTS (WAC 463-60-135)

2.2.1 LEGAL DESCRIPTION – PRINCIPAL FACILITIES

Units 3 and 4 will be located within the approximately 22-acre site approved by SCA for the Satsop Combustion Turbine Project (now the Grays Harbor Energy Center). See Attachment I to the existing SCA. In addition, a 10-acre site immediately to the east of the project site would be used for construction laydown and access and would become part of the project site (see Figure 2.2-1). The 10-acre site is not part of the existing SCA, and would constitute an expansion of the area governed by the SCA. The legal description for the 10-acre site is as follows:

> All that certain real property situate in Grays Harbor County, Washington designated as "Option B" on that certain Survey filed September 7,1999 in Book 20 of Surveys, pages 59 through 69, Grays Harbor County, and being described as follows:
>
> That portion of the Southwest One Quarter of the Southeast One Quarter and the Southeast One Quarter of the Southeast One Quarter of Section 7, Township 17 North, Range 6 West, W.M., in Grays Harbor County, Washington, described as follows:
>
> BEGINNING at the South One Quarter Corner of said Section 7, as monumented by an Iron Bar as shown on Record of Survey, Volume 11, Page 132; thence South 88E58'07" East along it's South line, 2479.21 feet to the Southeast corner of said Section 7, as monumented by a Department of Natural Resources concrete monument, as shown on Record of Survey Volume 11, Page 132; thence North 59E45'57" West 1047.69 feet to a

point on the North line of the Bonneville Power Administration Right-of-Way and the True Point of Beginning; thence South 84E18'36" West along said Right-of-Way, 453.55 feet; thence North 03E29'21" East 1010.02 feet to the Southerly margin of an unnamed road; thence South 88E50'40" East along said Southerly margin and said southerly margin extended, 438.66 feet; thence South 02E55'21" West 955.59 feet to the true point of beginning. Together with and subject to easements, restrictions, reservations and covenants of record.

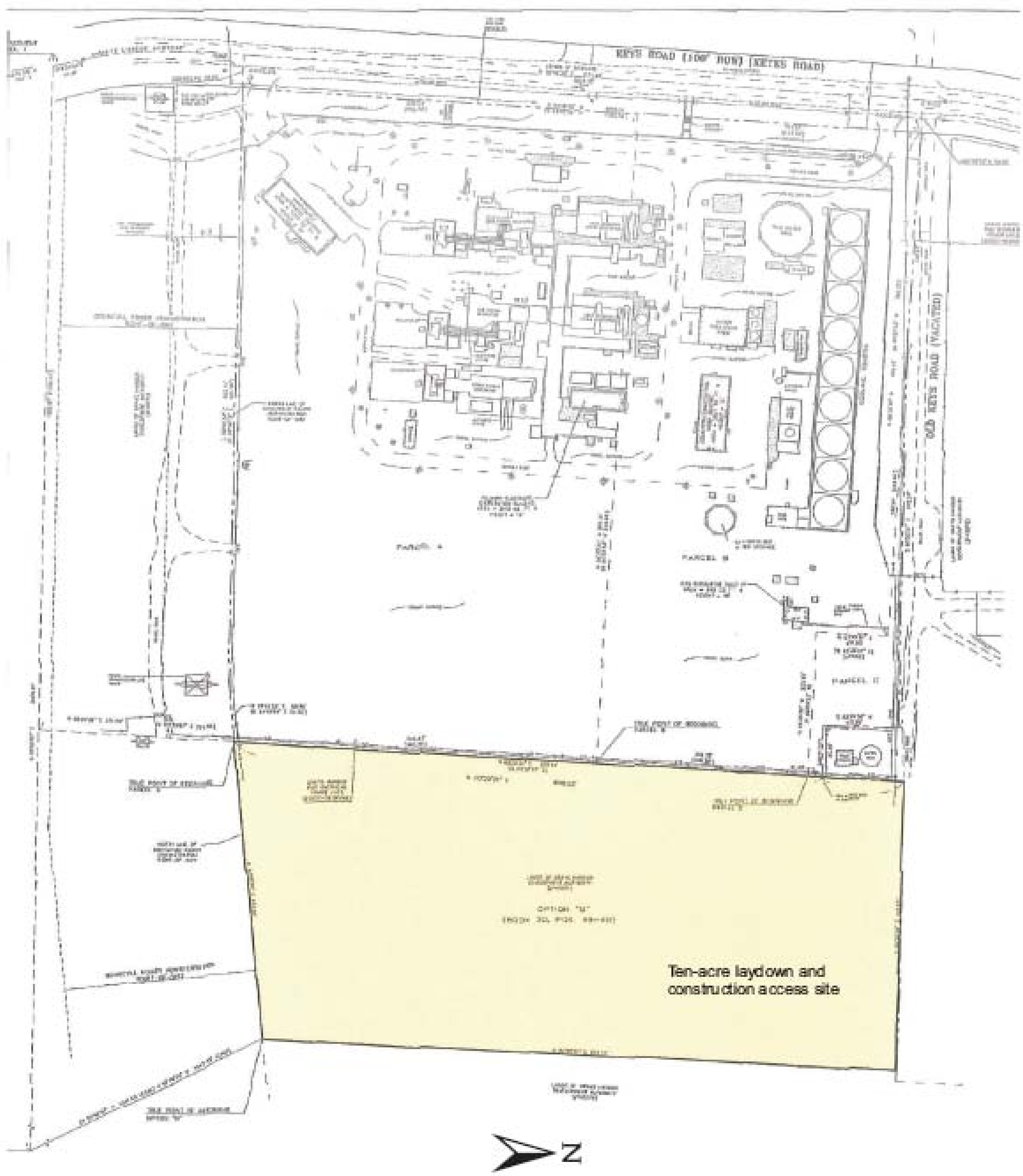


Figure 2.2-1
Ten-Acre Site Survey

SECTION 2.3 CONSTRUCTION ON SITE (WAC 463-60-145)

This section provides information on the proposed project and construction of the project in the following sections:

- Project Summary (Section 2.3.1)
- Power Plant Description (Section 2.3.2)
- Power Plant Construction (Section 2.3.3)

2.3.1 PROJECT SUMMARY

Grays Harbor Energy LLC (the Certificate Holder) is proposing to add two combustion turbine generators (Units 3 and 4) and a single steam generator to the Grays Harbor Energy Center. This will increase the maximum electrical generation capacity by approximately 650 MW, doubling the project's generating capacity. Certain facilities installed for the Grays Harbor Energy Center, such as the operations and control office, warehouse, workshops and stores, gas regulation and treatment, and the water treatment building also will serve Units 3 and 4, and new facilities of this type are not required.

Figures 2.3-1 and 2.3-2 present conceptual isometric diagrams of both the existing Grays Harbor Energy Center and the proposed addition of Units 3 and 4, respectively. Figure 2.3-3 is a plant configuration diagram for the addition, showing the major component systems. Figure 2.3-3 shows the major facilities/systems that will support the turbine trains, including the steam condensing/cooling system and the electrical interconnection system.

To support the expanded facility, additional process water will be obtained from a holder of an existing water right, such as the Grays Harbor PDA or the City of Aberdeen. The intake point would be the existing Ranney collectors and would be delivered via the existing Satsop Development Park water supply line that services the Grays Harbor Energy Center facilities. This water for Units 3 and 4 will be transported through an existing water pipeline that passes adjacent to the site (Figure 2.3-4). The existing outfall structure to the Chehalis River will continue to be used for discharge of the project's process effluent, without requiring any modification.

Potable water will be obtained from the existing Satsop Development Park raw water well. This system includes a supply tank and pump house located contiguous to the northeast corner of the site and will provide high-quality water that will be treated as necessary for potable uses.

Sanitary wastewater will be discharged through an existing on-site septic system and leach field constructed for the plant.

Fuel for Units 3 and 4 will be provided by the existing natural gas pipeline constructed as part of the Grays Harbor Energy Center.

Source: 3DScape

Figure 2.3-1
Existing Gray's Harbor Energy Project Isometric View

Power produced by Units 3 and 4 will be routed through new approximately 4,000-foot transmission lines that connect to the BPA system at the Satsop substation. The lines will be installed on existing structures that were constructed by BPA as part of the Grays Harbor Energy Center.

2.3.2 POWER PLANT DESCRIPTION

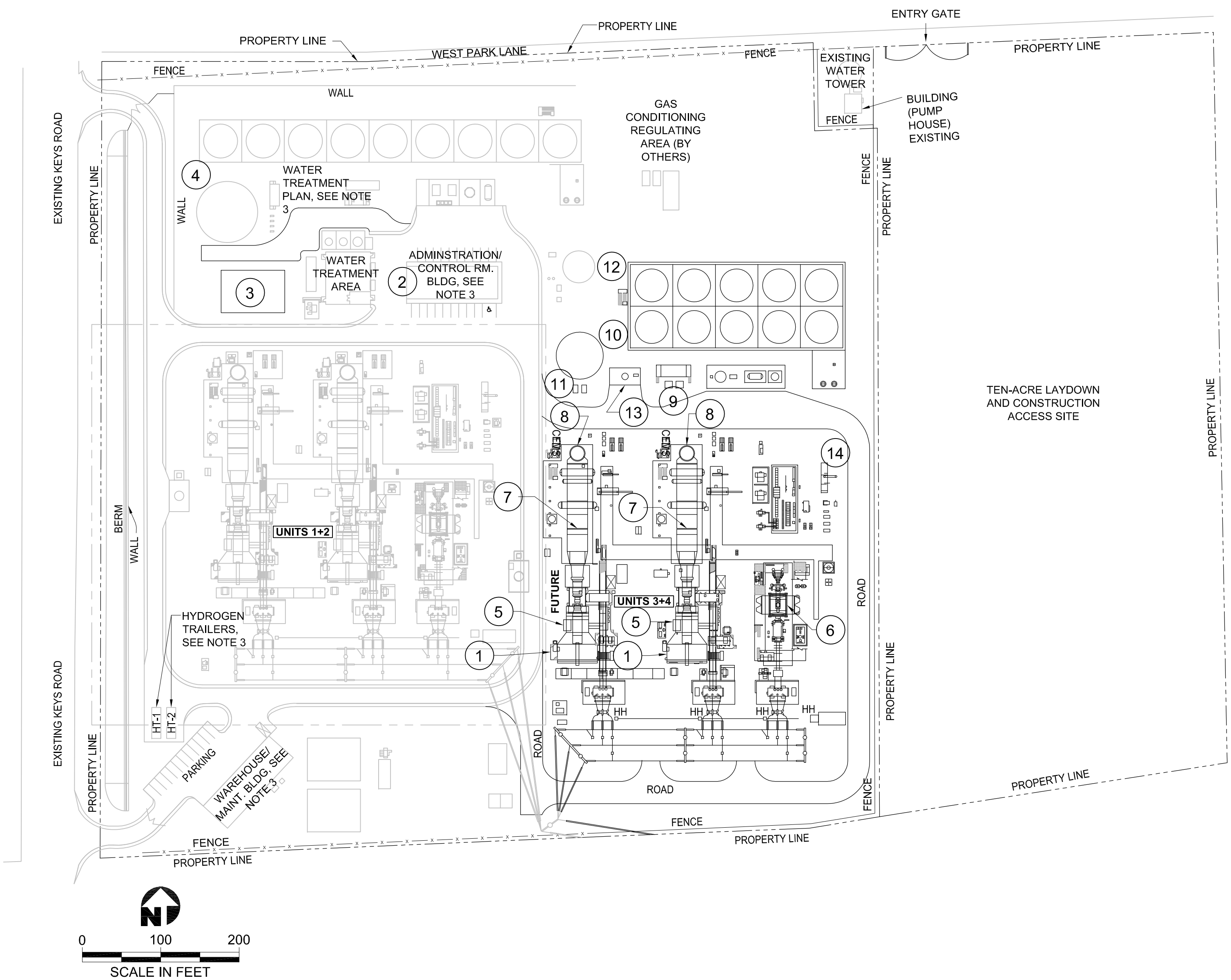
2.3.2.1 Overview

Units 3 and 4 will be combined cycle power generators with a combined nominal average capacity of 650 MW. Units 3 and 4 would be virtually identical to the existing Grays Harbor Energy Center Units 1 and 2. Like the existing units, Units 3 and 4 will be General Electric (GE) Frame 7FA combustion turbines in a 2-x-1 combined cycle configuration with a GE D11 steam turbine. Each GE 7FA combustion turbine generates a nominal gross power capacity of 175 MW, while the steam turbine generates approximately 300 MW gross with maximum duct firing at annual average temperature. The additional units also feature GE 7H2 hydrogen-cooled generators for the combustion turbine and stream turbine.


Source: 3DScape

Figure 2.3-2
Proposed Project with Units 3 and 4 Conceptual Isometric View

Section 2.3.2.2 presents a basic description of the components of Units 3 and 4, and Section 2.6, System of Heat Dissipation, WAC 463-60-175, describes the cooling systems. The basic building structures for the additional two units are shown on Figures 2.3-2 and 2.3-3, and Table 2.3-1 lists approximate heights of the major facility components.



KEY

1. GAS TURBINE HOUSING
2. ADMINISTRATION BUILDING
3. WORKSHOP AND STORES
4. WATER TREATMENT AREA
5. COMBUSTION TURBINE
6. STEAM TURBINE
7. HRSG
8. HRSG STACK
9. CIRCULATING WATER PUMPS
10. COOLING TOWER
11. RAW WATER TANK
12. DEMINERALIZED WATER TANK
13. AMMONIA TANKS
14. AUXILIARY BOILER STACK

NOTES

1. CONSTRUCTION LAYDOWN AND PARKING AREA.
2. ROUGH GRADING AND DRAINAGE IS EXISTING FROM UNITS 1+2.
3. THE FOLLOWING COMMON FACILITIES ARE LOCATED IN EXISTING DEVELOPMENT:
   - ADMINISTRATION/CONTROL ROOM BUILDING
   - WAREHOUSE/MAINTENENCE BUILDING
   - WATER TREATMENT
   - NATURAL GAS METERING YARD
   - HYDROGEN TRAILERS

Figure 2.3-3
Site Plan

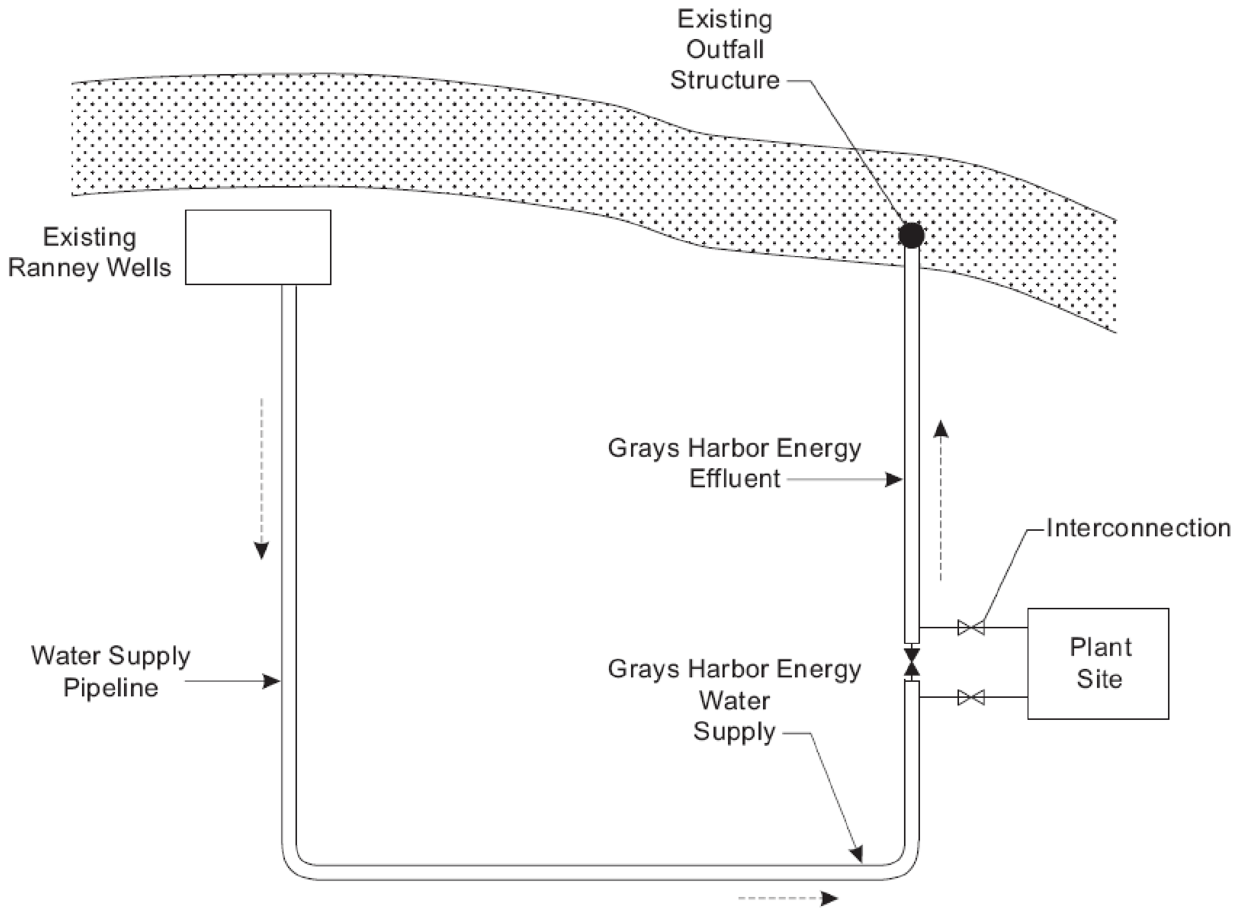


Figure 2.3-4
Process Water Conceptual Flow Diagram

TABLE 2.3-1
APPROXIMATE HEIGHTS OF MAJOR COMPONENTS

Component[a]	Approximate Height Units 1 and 2 (ft)	Approximate Height Units 3 and 4 (ft)
Gas Turbine (1)	57	26
Heat recovery steam generator (7)	85	80
Exhaust Stack (8)	180	180
Exhaust Stack - Auxiliary Boiler	49	49
Exhaust Stack - Diesel Generator	12	35
Firewater Pump	13	40
Cooling Tower (10)	48	52

a. Numbers in parentheses refer to key on Figure 2.3-3, Plot Plan.

2.3.2.2 Plant Components

Figure 2.3-3 shows the equipment configuration of the additional two units plus the existing two units. The project is made up of the following components:

- Combustion turbine generator (CTG) (two)
- Heat recovery steam generator (HRSG) (two)
- Steam turbine generator (STG) (one)
- Fuel supply
- Process water and wastewater treatment
- Cooling system
- Electrical interconnection
- Fire protection

The following is a summary description of the major components of Units 3 and 4.

Combustion Turbine Generator

The configuration incorporates two GE 7FA turbine generators, each with a gross capacity of approximately 175 MW. The GE 7FA is an industrial combustion gas turbine, including dry low-nitrogen (NO_x) burners, that represents the state of the art in combustion turbine technology. This turbine has been specified as the basis for the heat and material balance, fuel use, and emissions calculations.

Heat Recovery Steam Generator

The high temperature exhaust produced by the combustion turbines will flow directly to an HRSG, which will produce output steam at three pressure levels, all of which will supply steam directly to the steam turbine.

Emissions control (air pollution control) equipment is integrated within the HRSG. The selective catalytic reduction (SCR) control equipment for removal of NO_x and the oxidation catalyst for removal of carbon monoxide (CO) and volatile organic compounds (VOCs) are located within the HRSG.

Steam Turbine Generator

Steam from the HRSG will be delivered to the STG, which will have a gross capacity of approximately 300 MW.

An auxiliary boiler will be installed with a low-NO_x burner to produce steam at approximately 25,000 pounds per hour to provide sealing steam to the STG. It also can be used to maintain temperature in the HRSG during long idle time to reduce startup duration.

Fuel Supply

The fuel for the Grays Harbor Energy Center will continue to be natural gas only. The natural gas supply will connect to the metering station on site that has been constructed as part of the Grays Harbor Energy Center.

Process Water and Wastewater Discharge

To support the expanded facility, process water will be obtained from a holder of an existing water right, such as the Grays Harbor PDA or the City of Aberdeen. The water will be obtained through the existing Ranney collectors, located west of the plant site (Figure 2.3-4).

Ranney well water will continue to be delivered to the site via the existing supply water line. Effluent will continue to be sent back to the existing water pipeline via the existing connection downstream of the project intake, from where it will be transported and discharged to the Chehalis River through the existing outfall structure. The discharge will be governed by the facility's the National Pollutant Discharge Elimination System (NPDES) permit.

Cooling System

The proposed cooling system consists of two major components: 1) a circulating water system that will carry cooled water from the cooling tower through the steam turbine condenser and back to the cooling tower, and 2) an auxiliary cooling water system that will be tied into the circulating water system to provide water for cooling major equipment within the combined cycle facility. The evaporative cooling tower will consist of a 10-cell structure approximately 276 feet long, 114 feet wide, and 52 feet high.

Electrical Interconnection

Power generated by the Units 3 and 4 will be delivered to BPA's existing high-voltage transmission system at the Satsop 230 kilovolts (kV) substation. The power will be exported on lines to be installed for Units 3 and 4 on the existing tower structures constructed for Units 1 and 2, from the project site to the BPA Satsop substation, which is located approximately 4,000 feet east of the project site (Figure 2.1-1).

The switchyard containing necessary breakers, switching and transformer equipment will be modified for the additional two units.

Fire Protection

The fire protection system, including the fire water system, fixed suppression systems, detection systems, and portable fire extinguishers will provide the required fire protection for the project. The system for Units 3 and 4 will be similar to the system already installed at the Grays Harbor Energy Center and will consist of the following major components:

- Sprinkler systems
- Yard loop hydrant system

- Pre-action spray/sprinkler system for the steam turbine generator bearings and lube oil equipment
- Independent smoke detection system
- Portable fire extinguishers
- Standpipes and fire hose stations at various locations throughout the buildings
- Instrumentation and control equipment for alarm, indication of equipment status, and actuation of fire protection equipment, monitored in the Grays Harbor Energy control room.
- Combined raw/fire water storage tank
- Fire water pumps

Fire water will be stored in an on-site 1.3-million-gallon storage tank. There is an existing 1.3-million-gallon raw water storage tank for Units 1 and 2, which has a .3-million gallon fire water reserve. A second tank of similar size will be added for Units 3 and 4.

This storage capacity will be sufficient to provide the maximum automatic system demand plus 500 gallons per minute (as recommended by National Fire Protection Association 850) for a 2-hour period.

The fire water pumping system will consist of a primary electric motor-driven pump, a diesel-driven backup pump with independent fuel supply, and a pressure-maintaining jockey pump.

2.3.2.3 Project Layout

Figure 2.3-3 presents the site plan layout for the project. Buildings located on the site are shown on Figure 2.3-2. The locations of key components of each plant are described below.

The combustion turbine and generator, the steam turbine and generator, and their associated support equipment will be located within standard GE enclosures. The HRSGs will be located outside of the generation building.

The CTG-HRSG will be laid out in an in-line design parallel to the STG in a north-south orientation. The combustion turbine and the generator will be located at the south end within the power block and adjacent to the electrical switchyard. The northernmost structures will be the exhaust stacks, with the HRSG (and emission control equipment within the HRSG) located between the stack and the combustion turbine.

The electrical switchyard is located adjacent to the generator ends of the combustion turbines on the southernmost end of the site. Transmission lines extend from the switchyard to the Olympia-Aberdeen transmission line right-of-way that extends along the southern edge of the plant site (labeled “BPA Corridor” on Figure 2.1-2).

The natural gas pipeline enters the northern boundary of the plant site from the east.

2.3.3 POWER PLANT CONSTRUCTION

2.3.3.1 Construction Summary

The 22-acre site was previously graded and a layer of gravel was placed to prepare the site for use as a construction storage area for Units 1 and 2 of the Grays Harbor Energy Center. After excavation, foundations will be installed, as will the drainage system for the construction stage.

Materials to be used during construction are expected to be staged on the approximately 10-acre construction laydown area adjacent to and east of the existing project site (Figure 2.2-1). Access to the laydown area will be via West Park Lane. West Park Lane is an existing unimproved roadway that deadends to the east of the project site. The roadway will be improved with an all-weather driving surface as an early step in the construction. During construction, the plant site will remain fenced to provide site security. The Certificate Holder will purchase electricity needed for construction. Approximately 1.5 megavolt-amps (MVA) of 480-volt, 3-phase temporary power will be installed at a single location within the project site boundary. Startup power will be obtained from the Grays Harbor Energy Center.

Conventional construction equipment, including bulldozers, front-end loaders, trucks, tractor-scrapers, and graders will be used to final grade the site. During construction, dust will be controlled as needed by spraying water on dry, exposed soil. Prior to leaving the site during construction, vehicles will be sprayed with water and required to drive over a gravel pad to remove mud from the tires.

Site clearing and grading was completed during the original Grays Harbor Energy Center construction. Construction erosion control measures for Units 3 and 4 will be used in accordance with the requirements of the Certificate Holder's existing Erosion and Sedimentation Control Plan, which EFSEC approved on November 1, 2005.

Additional grading will be required to prepare the site for construction of Units 3 and 4. After site preparation is completed, the construction contractors will install the combustion turbine, steam turbine, generators, electrical and other equipment. Once these facilities are in place, the site landscaping will be initiated.

Field toilets and temporary holding tanks will be placed on site for construction personnel use. During construction, potable water from the project's existing water supply system will supply the contractor's needs. Parking and site access will be provided either on the 10-acre construction laydown area or on the PDA land west of Keys Road that was used for parking and staging during the original construction of the Grays Harbor Energy Center.

2.3.3.2 Site Preparation

There will be approximately 80,000 cubic yards of excavation for foundations, buried pipes (circulating water and fire loop), and the electrical duct banks. This material will be retained in the construction laydown area and later used for backfill.

A Phase I Environmental Site Assessment completed in April 1994 (Dames & Moore 1994) indicated that there is no evidence of contamination with hazardous materials at the site and that the likelihood of such contamination being present in subsurface soils is low. No contamination was identified during the excavation associated with construction of the Grays Harbor Energy Center facility on the site. If contamination is encountered during excavation and grading for Units 3 and 4, the Certificate Holder will notify EFSEC and take the appropriate remedial actions.

During site preparation, the construction contractor will install a storm drainage system. This system will consist of a series of swales that will convey surface water runoff into the existing Satsop Development Park storm drainage control system (Section 2.10, Surface-Water Runoff, WAC 463-60-215). An underground storm sewer and intakes will be installed under the power block area for Units 3 and 4, similar to the existing system used for Units 1 and 2.

A 6-foot high chain link fence was constructed as part of the Grays Harbor Energy Center surrounding the 22-acre plant site to provide security, and will be maintained during construction of Units 3 and 4. Also, a fence will be constructed between the existing facilities and the construction area, and around the construction laydown area to prevent construction activities and personnel from interfering with the operation of Units 1 and 2.

2.3.3.3 Foundations and Roadways

Foundations, including a pedestal for the steam turbine generator and foundations for the gas turbine generator and heat recovery steam generator equipment will be installed. As a part of final design studies, geotechnical investigations will be conducted to determine the appropriate types of foundations for the facilities. Based on currently available data, the Certificate Holder anticipates that foundations will be Category 1 facilities (non-essential facilities) in accordance with American Society of Civil Engineers Document 7-88 ("Minimum Design Loads for Buildings and Other Structures"). Foundations and buildings will be designed for Seismic Zone 3.

Construction of the project foundations will require the use of a number of types of heavy equipment, including excavation equipment, concrete-pumping equipment, and concrete finishing equipment. In addition, light- and medium-duty trucks, air compressors, generators, and other internal combustion engine driven equipment are anticipated.

On-site roadways and parking areas will be constructed with asphaltic concrete over a compacted sub-base.

An on-site concrete batch plant will not be required.

2.3.3.4 Equipment Installation

A number of the component systems of Units 3 and 4 will be fabricated and delivered to the site, including the CTG, HRSG, STG, major pumps, and electrical equipment. Fabrication and delivery of these components will be scheduled to coincide with their requirement in the construction sequence. Heavy and large equipment components will be delivered to the site by truck. Various sized cranes will be required to lift and place many of the pieces of component equipment into the required position.

In sequence with the installation of component equipment, support systems will be installed, including electrical equipment, control equipment, piping instrumentation, wiring cable, and conduits. Typical construction activities on site will include mechanical fastening, welding, preparation, and painting.

Cathodic protection will be provided on all underground gas lines within the site boundary.

2.3.3.5 Startup Testing

At the completion of the construction sequence, the plant system will be energized and operational testing undertaken. This will include testing each of the major component systems in a predetermined sequence and completion of quality assurance (QA) and quality control (QC) checks to ensure that each system is ready for full operation. After the total plant is fully operational, emissions compliance testing will be conducted. At the end of the startup testing phase, each unit will be separately certified for commercial operation. The QA/QC checks are described in detail in Section 2.12, Construction and Operation Activities, WAC 463-60-235.

SECTION 2.4 ENERGY TRANSMISSION SYSTEMS (WAC 463-06-155)

The Grays Harbor Energy Center will continue to be fueled by natural gas supplied by the existing natural gas pipeline. The natural gas pipeline is owned and operated by Williams Pipeline Company and is not subject to this SCA. Power will be transmitted via high voltage transmission lines owned and operated by BPA. The transmission lines also are outside of the scope of this SCA.

As described in Section 2.3, approximately 4,000 feet of new 3-phase transmission line will be added to the existing tower structures to connect Units 3 and 4 to the existing Satsop Substation.

SECTION 2.5 WATER SUPPLY SYSTEM (WAC 463-60-165)

2.5.1 PROCESS WATER SUPPLY

Process water will continue to be supplied from the existing Ranney wells and transported through the existing supply water line (Figure 2.3-4). The Ranney wells are located on the southern bank of the Chehalis River, approximately 4 miles downriver of the plant site near the river's confluence with Elizabeth Creek. The wells penetrate into the alluvial aquifer associated with the Chehalis River to a depth of approximately 120 feet. The Ranney wells obtain approximately 88 percent of their water from the Chehalis River via drawdown, with the remaining 12 percent drawn from groundwater in the surrounding river alluvium. Groundwater availability in river alluvium of the Chehalis River valley from each Ranney well is as high as 40 cubic feet per second (cfs), or 18,000 gallons per minute (gpm). Additional information on water quality and quantity associated with the Ranney wells is presented in Section 3.3, Water, WAC 463-60-322.

Water from the Ranney wells will continue to be transported to the Grays Harbor Energy Center site via the existing supply water line and the existing discharge (blowdown) line. At the Grays Harbor Energy Center site, a pipe connects the blowdown line to transport process supply water to the project. Detailed design, location, and connection information on the Ranney wells and on the existing distribution system used to supply water to the Grays Harbor Energy Center were presented in the Washington Public Power Supply System (WPPSS) application for an SCA, in the SCA issued by EFSEC, in documents subsequently submitted to EFSEC, and in the WPPSS Environmental Report - Operating Licensing Stage (WPPSS 1982) and Final Safety Analysis Report (WPPSS 1984).

The existing SCA allows the Certificate Holder to use up to 9.2 cfs of water to operate the facility, and includes a Water Authorization that allows the Certificate Holder to withdraw up to 9.2 cfs of water from the Ranney Wells, except during low flow periods. During low flow periods, the Certificate Holder may continue operating the facility by obtaining water from another water rights holder, as long as the water is derived from water rights that are not subject to low flow restrictions. As part of this application, the Certificate Holder is requesting an amendment to the existing SCA to allow the Grays Harbor Energy Center to use up to a maximum of 16 cfs of water.

During non-low flow periods, the Certificate Holder would withdraw up to 9.2 cfs pursuant to the existing Water Authorization and obtain additional water from another water right holder or holders. During low flow periods, the Certificate Holder would obtain the entire needed amount from a holder or holders of water rights that are not subject to low flow restrictions. The Certificate Holder is currently in negotiations with both the Grays Harbor PDA and the City of Aberdeen to obtain the needed water. In either case, the water would be withdrawn from the existing Ranney wells. The PDA's water right already authorizes withdraw of its water from the existing Ranney wells. If the Certificate Holder enters into an agreement to lease water from the City of Aberdeen, the agreement would be contingent upon the City obtaining approval from the Department of Ecology to allow the water to be withdrawn from the Ranney Wells.

2.5.2 POTABLE WATER SUPPLY

Water for potable uses will continue to be supplied by the PDA’s potable water system. Anticipated potable and service water demand for the additional staff needed to operate Units 3 and 4 is approximately 50 gpm maximum, and will average less than 20 gpm. Water supplied by the Satsop Development Park is chlorinated, and if needed, additional treatment will be made prior to delivery to the Grays Harbor Energy Center.

SECTION 2.6 SYSTEM OF HEAT DISSIPATION (WAC 463-60-175)

For Units 3 and 4, an additional cooling system will be constructed. The cooling system proposed for Units 3 and 4 is similar to the system used for the existing Units 1 and 2. It consists of two primary components: 1) a circulating cooling water system, and 2) a mechanical draft cooling tower. Steam supplied to the STGs will be exhausted from the steam turbine and condensed in the steam condenser. The circulating cooling water system, operating at a flow of approximately 66,000 gpm, will route cool water to the condenser and auxiliary cooling system.

The auxiliary cooling system will provide cooling for the generator cooling circuit, boiler feed pump, sampling/analysis panel, and lubrication oil cooling circuit. At the condenser and the auxiliary cooling system, heat will be transferred to the circulating water. The warmed water will then be routed to the cooling tower, where the temperature will be reduced before being returned to the cooling system.

The cooling tower will continuously receive the heated cooling water from the plant. The heated water will enter the tower near the top and will be sprayed downward through the tower. A large fan on top of the tower will pull air through openings in the bottom of the tower, moving air counter to the water sprays and cooling the water through evaporation. The temperature of the water will be reduced to approximately 90° F when it reaches the cooling water basin, where it will be collected and returned to the cooling system. This cycle will be repeated until the circulating water needs to be replaced as described below in subsection 2.8.1.1.

SECTION 2.7 CHARACTERISTICS OF AQUATIC DISCHARGE SYSTEMS (WAC 463-60-185)

Units 3 and 4 will use the same blowdown line and outfall that is used by Units 1 and 2, without any modification. The outfall includes a diffuser, which was designed to disperse the effluents as required to comply with the NPDES permit (Permit No. WA-002496-1). Detailed information on the design, location, and construction of the outfall is presented in documents previously submitted to EFSEC.

The existing blowdown line and outfall are owned by the Grays Harbor PDA. The 1999 transfer agreement between Energy Northwest and the Satsop Redevelopment Project guarantees the use of the blowdown line and outfall for Grays Harbor Energy Center discharges.

An existing NPDES permit governs wastewater discharges from the Grays Harbor Energy Center and stormwater discharges from the Satsop Development Park. As described in Section 2.8, Wastewater Treatment, WAC 463-60-195, effluent from Units 3 and 4 would comply with the conditions of the existing NPDES permit.

SECTION 2.8 WASTEWATER TREATMENT (WAC 463-60-195)

This section provides information on the proposed process wastewater discharge streams and alternative systems in the following sections:

- Process Wastewater Streams (Section 2.8.1)
- Wastewater Analyses (Section 2.8.2)
- Regulatory Compliance (Section 2.8.3)
- Bypass and Overflow Facilities (Section 2.8.4)
- Alternative Methods (Section 2.8.5)

2.8.1 PROCESS WASTEWATER STREAMS

The Grays Harbor Energy Center has been designed to minimize wastewater discharges, with only a single process wastewater stream to be discharged from the entire project (including Units 3 and 4). The design for Units 3 and 4, as for the existing Units 1 and 2, includes waste streams that will be treated as necessary and co-mingled prior to discharge. These waste streams consist of cooling tower blowdown and oil/water-separator decant. The co-mingled waste streams from both the existing and proposed units will be discharged to the Satsop Development Park's blowdown line in accordance with the NPDES permit for the Grays Harbor Energy Center (Permit No. WA-002496-1). The outfall discharges to the Chehalis River.

2.8.1.1 Water Treatment System Units and Discharge

Cooling Tower Blowdown

The cooling towers will continuously receive the heated cooling water from Units 3 and 4. Heated water will enter the tower near the top and will be sprayed downward. Evaporation in the cooling towers will result in a loss of cooling water, and the constituents of the cooling water will be concentrated due to evaporation. At high concentrations, some of these constituents could cause scaling in the heat exchanger surfaces. Therefore, after cooling water has repeatedly circulated through the cooling cycle, a small portion will be removed from each cooling tower basin and discharged in accordance with the NPDES permit. (This discharge is termed cooling tower "blowdown.") To replenish the circulating cooling water, additional Ranney well water and the neutralized plant waste streams will be added to the cooling water. The three plant waste streams are the water treatment regeneration discharge, the cooling tower blowdown, and the plant sump discharge as described below.

Since the cooling water will be repeatedly circulated before being discharged, several of the constituents of the cooling water will be concentrated to a point that could result in corrosion. Therefore, an alkaline phosphate treatment is necessary. Chemicals proposed for use in the cooling tower include an acrylic polymer (dispersant), tolytriazole (copper corrosion inhibitor), phosphonocarboxylate (iron corrosion inhibitor), phosphonate (iron corrosion inhibitor), and sulfuric acid (alkalinity control). Because the circulating water is exposed to atmospheric microbiological contaminants, sodium hypochlorite will be used as a biocide to minimize microbiological growth. During treatment with sodium hypochlorite, the blowdown discharge valve will remain closed to prevent the release of chlorine. The majority of chlorine will dissipate from the cooling tower basin while the blowdown valve is closed. The retained wastewater will be sampled and analyzed prior to discharge as blowdown.

The types of chemicals used for treatment are listed in Table 2.8-1. The constituents of these chemicals used for treatment of the cooling tower water system are not on the list of toxic substances regulated under WAC 173-201A-040 (Water Quality Standards for Surface Waters in Washington State). The chemicals used for treatment of the cooling water will either be neutralized or evaporated out of the effluent stream or will be at undetectable concentrations.

TABLE 2.8-1
TYPICAL CHEMICALS USED IN COOLING WATER SYSTEM (PER UNIT)

Chemical	Description and Use	Estimated Usage Rate (pounds per day)
Nalco - Dynacool - 8301D or equivalent (dispersant: acrylate polymer)	Liquid polymeric dispersant used in circulating water treatment system.	58
Nalco - Dynacool - 8308 or equivalent (corrosion inhibitor: phosphonate, phosphonocarboxylate, tolyltriazole)	Liquid phosphate-based corrosion inhibitor used in circulating water treatment system.	116
Sodium hypochlorite	Liquid water treatment chemical for the cooling tower.	111
Sulfuric acid	Liquid water treatment chemical used in demineralizer and in neutralization tank.	335

The cooling tower blowdown water will be co-mingled with the waste stream from the oil-water separator and discharged to the blowdown line to the Chehalis River. The expected flow for Units 3 and 4 will be a maximum of 660 gpm, and a maximum of 1,320 gpm for the combined Units 1 through 4.

The NPDES permit regulates discharges through the blowdown line and outflow structure. The Certificate Holder does not believe the addition of Units 3 and 4 will necessitate any amendment to the NPDES permit. If an amendment were deemed necessary, the NPDES permit could be amended prior to operation of the new units and after the amendments to the existing NPDES permit are completed.

Oil-Water Separator

The oil-water separator will be provided for waste streams that may contain oily water, such as the steam turbine oil purification system and floor and equipment drains. The oil-water separator will receive and separate water and oil mixtures. Water from the separator will be co-mingled with the cooling tower blowdown prior to discharge to the Satsop Development Park's blowdown line, while the oil is retained for eventual removal and disposal. The oil-water separator will be a prefabricated modular fiberglass reinforced plastic, cast-in-place concrete structure, or a packaged steel tank type system. The discharge piping will be designed with a leg extending below the maximum design oil depth, which will allow only oil-free water to be discharged. A reservoir included with the oil/water separator will collect the waste oil for off-site recycling or disposal by a licensed contractor.

Large tanks containing oil will be diked and valved to retain any large oil spills in place for mitigation and cleanup.

Sanitary Wastes

Sanitary wastes are treated at on-site septic tank systems operated in accordance with the applicable state and Grays Harbor County codes. The existing septic system is designed for 34 staff per day. For the operation of all four units, approximately 20 employees would work two

12-hour shifts with a maximum of 31 employees working on site at any one time. The existing septic system will be able to accommodate the additional staff employed for Units 3 and 4.

2.8.1.2 Internal Waste Streams

HRSG Blowdown (Internal Stream)

A small stream (90 gpm) will be drained from the HRSG to remove the constituents of the make-up water that become more concentrated due to evaporative losses during operation (steam production). This “blowdown” from the HRSG will be routed to a blowdown tank before being piped to the cooling tower for use as make-up water. The purpose of the tank is to absorb the “flashing” (the rapid and forceful decrease in temperature and pressure during blowdown release) as blowdown water is released from the HRSG.

Regeneration Waste (Internal Stream)

Approximately 8 gpm of regeneration waste will be discharged from the demineralized water plant to the cooling tower basin.

Plant Sump Discharge (Internal Stream)

Each plant sump will receive minor wastewater streams from the condensate pump pit, the transformer containment structure drains, and the area sump drains. Wastewater in the plant sump will be routed to an oil-water separator.

2.8.2 WASTEWATER ANALYSES

Wastewater analyses were conducted on the Grays Harbor Energy discharge at Outfall 001 to measure concentrations of constituents in the site’s discharge and compare it to the quality of the receiving water (the Chehalis River). Discharge at Outfall 001 was also compared to the water quality criteria specified in WAC 173-201A (Water Quality Standards for Surface Waters of the State of Washington) and the NPDES Permit.

Constituents of the receiving water (Chehalis River), influent process water (concentrations of chemical constituents of Ranney well water), and discharge concentrations (concentrations in process water discharged from Units 1 and 2 at Outfall 001) are presented in Table 2.8-2.

2.8.2.1 Receiving Water

Water quality data for the Chehalis River are collected monthly at station 23A070 located near Porter, Washington as part of the Washington State Department of Ecology (Ecology) Statewide Water Quality Monitoring Network. Station 23A070 is approximately 11 miles upstream from the project site.

TABLE 2.8-2
WATER QUALITY CRITERIA AND ANALYSES

Parameters	WAC 173-201A Criteria[a]		NPDES Permit[b]		Influent Conc. (Ranney Wells) (mg/L)[c]	Chehalis River Water Quality (mg/L)[d]	Discharge Conc. at Diffuser Daily Max. (mg/L)[e]	Discharge Conc. at Diffuser Monthly Average (mg/L)[e]	Mixing Zone Boundary Conc.[f]	
	Acute Criteria (mg/L)	Chronic Criteria (mg/L)	Daily Max. (mg/L)	Monthly Average (mg/L)					Acute Criteria (mg/L)[f]	Chronic Criteria (mg/L)[f]
Temperature (°C)	22	18	16	N/A	NAv	2.8-25.4	6.9-18.6	11.7	11.7[h]	11.7[h]
Ammonia (as N)	pH dependent		321	160	NAv	0.01 - 0.024	0.93	0.37	0.04429	0.00511
Chlorine	19	11	0.5	0.2	NAv	N/A	0.21	0.03	0.01000	0.00115
Chloride	860	230	18	9	3.8	N/A	93.6	52.8	4.45714	0.02449
pH	6.5-8.5	NA	6.5-8.5	NA	7.68	6.77-8.04	6.3-9.3	7.44	7.44[h]	7.44[h]
TSS	NE	NE	100	30	NAv	2-31	20	14.2500	0.95238	0.10989
Arsenic	0.36	0.19	note g	note g	0.00088	0.0002 - 0.0035	0.49	0.0900	0.02333	0.00269
Chromium	0.2	0.065	0.2	0.2	0.00026	<0.0005 - 0.0028	0.05	0.016	0.00238	0.00027
Iron	NE	NE	1	1	0.0735	0.107	9.65	3.0400	0.45952	0.05302
Copper	0.0053	0.0039	note g	note g	0.00039	0.0014 - 0.0072	0.0057	-	0.00027	0.00003
Cadmium	0.0019	0.00041	note g	note g	ND	<0.00001	ND	-	ND	ND
Lead	0.0174	0.00064	note g	note g	0.00044	<0.0001 - 0.00089	ND	-	ND	ND
Mercury	0.0021	1.2E-05	note g	note g	ND	0.0000021- 0.00001	ND	-	ND	ND
Nickel	0.5	0.055	note g	note g	ND	0.0004 - 0.0099	0.0014	-	0.00007	0.00001
Selenium	0.02	0.005	note g	note g	0.00027	<0.002	0.0011	-	0.00005	0.00001
Zinc	0.04	0.037	note g	note g	ND	0.0004 - 0.0018	0.0209	-	0.00100	0.00011

Notes:
NAv=Not Available, N/A=Not Applicable, NE=criterion not established, ND=non detect

a. Metals concentrations are the total fraction. Acute: In general, refers to a 1-hour average concentration not to be exceeded more than once every three years on the average. Chronic: In general, refers to a 4-hour average concentration not to be exceeded more than once every three years on the average. Hardness dependent criteria are calculated with a hardness of 30.5 mg/L.

b. NPDES permit effluent limitations (EFSEC 2008). Note: Chloride concentrations listed in the NPDES permit are incorrect due to a typographical error.

c. Data from Ranney Wells collected 8/5/09. Results shown are the maximum of two samples collected on 8/5/09.

d. Except for iron and selenium, Chehalis River water quality data are from the Ecology water quality monitoring station 23A070 located near Porter, WA, approximately 11 miles upstream from the project site; metals chemistry data was collected in 2002 while conventional parameter data was collected in 2007. Iron and selenium data were collected in 1981 from the intake area (Envirosphere 1982).

e. Data from daily monitoring at Outfall 001 between July 2008 and July 2009 and priority pollutant sampling at Outfall 001 on 8/5/09 and 7/27/09.

f. Using dilution factors stated in the NPDES permit as follows: Chronic Mixing Zone = 182 and Acute Mixing Zone = 21. Dilution factors are applied to the Daily Maximum Discharge Concentration at Diffuser.

g. The NPDES water quality-based limitations must comply with the surface water quality standards (Chapter 173-201A WAC) or the National Toxics Rule (40 CFR 131.36) (EFSEC 2008). There must be no discharge of polychlorinated biphenyls. There must be no detectable amount of priority pollutants (listed in 40 CFR Part 423, Appendix A) and polychlorinated biphenyls in the effluent from chemicals added for cooling system maintenance.

h. Mixing boundary concentrations for temperature and pH were calculated based on the average monthly discharge concentration at the diffuser.

2.8.2.2 Influent Process Water

Water quality data from the Ranney well collector system were assumed to represent influent process water quality. Ranney well water samples were collected by Grays Harbor Energy on August 5, 2009 and the laboratory analyses for each constituent presented in Table 2.8-2 was performed by Dragon Analytical Laboratory. The metals concentrations used for the analysis were the dissolved fraction. Total metal concentrations include the sediment fraction, which would be expected to be insignificant as the Ranney well gravel pack is developed by pumping, and sediment is removed due to settling in the cooling tower basin.

2.8.2.3 Discharge Water Quality

Discharge concentrations in Table 2.8-2 were obtained from two separate sampling events. Temperature, pH, ammonia, chlorine, total suspended solids (TSS), chloride, arsenic, and chromium data were obtained from daily monitoring samples taken at Outfall 001 between July 2008 and July 2009 (May and June of 2009 were not included due to irregular plant operation that lead to non-representative concentrations of the measured constituent). Copper, cadmium, lead, mercury, nickel, selenium, and zinc concentrations were obtained from a sampling effort for determining priority pollutant concentrations at Outfall 001. The results from the priority pollutant sampling are from two samples taken (July 27, 2009 and August 5, 2009) and the results shown in Table 2.8-2 are the maximum concentrations of these two samples. Monthly averages are not provided for copper, cadmium, lead, mercury, nickel, selenium, and zinc because they were only measured from the two priority pollutant samples.

Discharge water quality in Table 2.8-2 is shown as both daily maximum and monthly average concentrations. Daily maximum and monthly average concentrations were included because, due to irregular plant operation, daily maximum concentrations were not considered representative. Units 1 and 2 came into operation in July 2008. Continuous discharge data during this first year was collected during August and September of 2008 and July of 2009. Discharge data for the remaining months is intermittent. During the first year of operation, the facility has been operated at intervals dependant upon energy demand. An inherent issue with a facility that is operated in this manner is that certain constituents may have increased concentrations in the discharge due to a flushing effect when units are placed back into operation after a period of downtime.

The daily maximum concentrations for the constituents presented in Table 2.8-2 (with the exception of temperature and pH) were divided by the acute and chronic dilution factors (21 and 182, respectively) to achieve mixing zone boundary concentrations. The monthly average concentration for temperature and the daily maximum pH values were used instead of the daily maximums because the daily maximum temperature and pH are not considered to be representative of normal plant operation.

2.8.3 REGULATORY COMPLIANCE

When compared to the NPDES permit limits presented in Table 2.8-2, the facility would be compliance at the mixing zone boundary for both acute and chronic concentrations of all the constituents sampled.

2.8.4 BYPASS AND OVERFLOW FACILITIES

No bypass facilities are included in plant design. All tanks would be equipped with overflow drains to prevent catastrophic losses. The discharge from overflow drains from chemical tanks would be directed to a containment basin around each tank, and each containment basin would be designed to hold 110 percent of the contents of the tank. Containment basins would be used to retain the collected fluids until a manual valve in the discharge piping is opened. Discharge from the demineralization plan containment basins would be routed to the neutralization tank for treatment. Administrative procedures require inspection of containment basin content.

2.8.5 ALTERNATIVE METHODS

The infrastructure and permit for discharge into the Chehalis River already exist, are currently used for the Grays Harbor Energy Center, and thus provide the most cost-effective and efficient approach to wastewater treatment for Units 3 and 4.

Zero discharge is another alternative approach. Zero discharge systems recycle and evaporate the water portion of wastewater and concentrate the solids for eventual off-site disposal. In this process, no wastewater is discharged. The zero discharge system was rejected because no water would be returned to the river to supplement flows, there appears (at this time) to be no significant impacts to water quality of the Chehalis River. A zero discharge system is also prohibitively expensive.

The approach selected for Units 3 and 4 minimizes plant wastewater discharges by recycling internal wastewater streams as make-up water for the cooling towers. However, some wastewater (up to 3.0 cfs for the entire Grays Harbor Energy Center) would be discharged to the Chehalis River, returning a portion of the water pumped from the Ranney wells (which obtain 88 percent of their water from the river). This is considered a beneficial condition since the wastewater returned to the river meets both NPDES permit criteria and state water quality standards.

Use of a deep well injection system represents another alternative method of wastewater handling. However, this approach is rarely used in power generation facilities. Deep well injection systems depend on the nature of the site's underlying aquifer, and are typically very difficult to permit. In addition, the water would not be recharged to the aquifer from which it is extracted. Due to the many risks associated with deep well injection, this alternative was rejected.

SECTION 2.9 SPILLAGE PREVENTION AND CONTROL (WAC 463-60-205)

2.9.1 MATERIALS STORED ON SITE

Chemicals to be used and stored for the additional two units are the same as those used and stored for the existing Grays Harbor Energy Center. They consist of specialty and bulk/commodity chemicals and a minimal amount of fuel oil for small backup generators.

2.9.2 SPILL PREVENTION CONTROL AND COUNTERMEASURES PLAN

The Certificate Holder has an existing Spill Prevention Control and Countermeasures (SPCC) Plan for the Grays Harbor Energy Center that will also be applicable to Units 3 and 4. Revisions of the SPCC Plan were approved by EFSEC on September 15, 2008, and revisions to the Hazardous Waste Management procedure were approved by EFSEC on January 7, 2008. Revisions will be made, if necessary, to respond to changing site organizations or conditions, or changes in regulations.

The existing SPCC Plan describes the oil, fuel, and hazardous material storage facilities; reporting systems; prevention requirements; and spill response procedure. The Hazardous Waste Management procedure establishes a program for the handling, storage, and disposal of wastes from the Grays Harbor Energy Center site.

SECTION 2.10 SURFACE WATER RUNOFF (WAC 463-60-215)

2.10.1 INTRODUCTION

The Certificate Holder has an Erosion and Sedimentation Control Plan and an Environmental Protection Control Plan that were approved by EFSEC on September 19, 2001. These plans provide surface water runoff controls during both construction projects and operational activities and are applicable for construction and operation of Units 3 and 4. The following sections summarize the procedures that the Certificate Holder anticipates using to control erosion and surface water runoff during construction and operation of the proposed project.

2.10.2 EROSION CONTROL DURING CONSTRUCTION

This section presents information on the erosion control practices to be followed during construction and additional information on erosion control during construction at the plant site.

Erosion control measures will be used in accordance with the requirements of the approved Erosion and Sedimentation Control Plan. The Certificate Holder does not anticipate the need to modify this plan. However, the Certificate Holder will do so should conditions of the SCA amendment require modifications.

The Environmental Protection Control Plan establishes a monitoring and control program that documents all site environmental activity, including events or activities that do not comply with environmental commitments. The plan establishes administrative procedures to communicate such events or activities to site management and to bring about corrective action. Stop-work steps are given in the event that an activity is observed to be in violation of permits or environmental regulations.

Erosion and sediment control best management practices (BMPs) consistent with those in the *Stormwater Management Manual for Western Washington* (Ecology 2005) will be employed during construction of Units 3 and 4 and will comply with the requirements of the existing Erosion and Sedimentation Control Plan. BMPs will include limiting certain construction activities and installing temporary control structures such as sediment traps and silt fences.

Generally, erosion control measures will include measures such as silt fences, diversion ditches, hydroseeding, and sediment traps.

Construction activities will be controlled to the extent possible to help limit erosion. Clearing, excavation, and grading will be limited to areas absolutely necessary for construction of the project. Areas outside the construction limits will be identified and clearly marked, and equipment operators will be instructed to avoid these areas.

The area proposed for Units 3 and 4 was previously graded and covered with a layer of gravel for use as an equipment and material laydown area during construction of the existing project. Additional grading will be required to prepare the site for construction of the additional two units.

Runoff from the northern portion of the site will continue to be routed through existing ditches and culverts to the C-1 pond, which is located on Satsop Development Park property to the west. If necessary, surface water runoff from the site can be pumped through a series of ditches and culverts to the existing Equalization Pond on the main Satsop Development Park property. This pond would provide additional storage capacity during construction if surface water runoff is unusually high.

2.10.3 STORMWATER POLLUTION PREVENTION

The existing SCA provides the basis for the stormwater pollution control program. Used in conjunction with the existing Erosion and Sedimentation Control Plan, the existing NPDES permit and EFSEC resolutions will ensure compliance with water quality standards.

2.10.3.1 Construction

The Certificate Holder currently has an approved NPDES permit that covers stormwater discharges, including stormwater discharges from the proposed plant site. In addition, the SCA addresses stormwater management during construction, and includes the following requirements:

- The project must comply with all pertinent industry standards for control of any unforeseen surface water runoff event during construction, and must notify EFSEC of surface water runoff problems
- The project must abide by turbidity criteria for construction-related runoff as established in the State of Washington Water Quality Standards

The existing NPDES permit establishes water quality limits and monitoring schedules for total suspended solids, settleable solids, and pH in collected stormwater runoff. These limits are applicable for material storage runoff and construction runoff within the 100-year, 24-hour rainfall event (5.4 inches per 24 hours).

2.10.3.2 Operation

Runoff from the plant site will be directed toward the perimeter ditches and routed as described in Section 2.10.2. BMPs consistent with those in the *Stormwater Management Manual for*

Western Washington (Ecology 2005) will continue to be employed during operation of the Grays Harbor Energy Center.

At least annually, facility employees will also receive training in the pollution control laws and regulations, and the specific features of the facility which are intended to prevent releases of oil and petroleum products. Employees at the site will be trained in the following spill response measures:

- Identifying areas that may be affected by a spill and potential drainage routes
- Reporting of spills to appropriate individuals
- Employing appropriate material handling and storage procedures
- Implementing spill response procedures

Stormwater catchbasins and detention systems will be inspected at least annually as part of the site preventive maintenance program. Stormwater catchbasins will be cleaned if the collected deposits fill more than one-third of the depth from the basin to the invert of the lowest pipe leading into or out of the basin.

Inspections will be conducted to confirm that non-permitted discharges are not entering the stormwater system. A summary of each inspection will be retained, along with any notifications of noncompliance and reports on incidents such as spills.

SECTION 2.11 EMISSION CONTROL (WAC 463-60-225)

2.11.1 INTRODUCTION

This section identifies emissions of criteria and toxic air pollutants (TAPs) resulting from the proposed addition of Units 3 and 4 to the Grays Harbor Energy Center and describes the emission controls that have been incorporated in the proposed design. Criteria pollutants are air pollutants governed by National and Washington Ambient Air Quality Standards (NAAQS and WAAQS). Toxic air pollutants are certain chemicals that Washington has characterized as toxic in WAC 173-460-150. Greenhouse gas emissions are also quantified and proposed mitigation is identified.

Emissions would be controlled by application of Best Available Control Technology (BACT), and would comply with federal and state emission standards. BACT would be determined by EFSEC as it prepares the Order of Approval and the Prevention of Significant Deterioration (PSD) permits for the project. On-going compliance with the approval conditions established by these permits would be ensured by an air operating permit. The permit application for the operating permit must be filed within a year of startup, and is typically in place within the following year.

Grays Harbor Energy LLC proposes to add two GE Frame 7FA combustion turbines to the existing Grays Harbor Energy Center. Each combustion turbine would have a Heat Recovery Steam Generator (HRSG) and supplemental duct firing. Steam generated by the HRSGs would power a single, shared steam turbine generator.

Additional components include an auxiliary boiler, a cooling tower, a diesel-fueled internal combustion engine driving a firewater pump, and a diesel-fueled generator. Emissions from these new sources are described in the following subsections, along with explanations of the controls that would be applied to specific sources to minimize these emissions. In the discussion that follows, we will refer to the proposed addition of two combustion turbines and HRSGs, a boiler, a cooling tower, and two engines as "Units 3 and 4."

2.11.2 CRITERIA POLLUTANTS

Because the site is partially developed already, grading and excavation associated with construction of the facility (and associated fugitive dust) would be limited to preparing for structure foundations. The construction contractor will take precautions to minimizing fugitive dust.

In addition, welding, painting, paving, and operation of a variety of internal combustion engines would generate gaseous emissions during construction. Because these tend to be relatively small emissions sources that are typically scattered throughout the site, such sources rarely have significant off-site impacts.

2.11.2.1 Best Available Control Technology

EFSEC's determination as to what constitutes BACT at the time of the final permit review would define emission limits from all emission units associated with Units 3 and 4. BACT is addressed for all Units 3 and 4 emission units in the BACT analysis provided as Appendix A-1.

USEPA has established performance standards for a number of air pollution sources in 40 CFR Part 60, including combustion turbines and HRSGs with duct burners, auxiliary boilers, and diesel-fueled internal combustion engines. These "new source performance standards" usually represent a minimum level of control that is required for a new source.

USEPA regulates new stationary gas turbines (and duct burners) in 40CFR60 Subpart KKKK. Subpart KKKK limits NOx emissions to 15 ppm and SO_2 emissions to 0.90 lb/MWhr, or 615 lb/hr for the proposed combustion turbines at maximum operating conditions. As discussed below, NOx and SO_2 emissions from the Units 3 and 4 combustion turbines would be well below these NSPS limits.

All of the recent permits issued in Washington (and most in the United States) have determined that Selective Catalytic Reduction (SCR) constitutes BACT for combustion turbines with HRSGs. SCR is a post-combustion NOx control device that uses a catalyst and ammonia to reduce NOx to nitrogen. Grays Harbor Energy LLC proposes that BACT for NOx emissions from its combustion turbines and HRSGs is SCR with a NOx limit of 2 ppmvd at 15% oxygen, averaged over three hours.

Grays Harbor Energy LLC proposes to include an oxidation catalyst in the HRSG to reduce CO emissions to 2 ppm at 15% oxygen. The oxidation catalyst will also reduce VOCs and certain toxic or hazardous pollutants such as formaldehyde. Consistent with other recently permitted sources, the use of natural gas and proper combustion will provide BACT for volatile organic compounds, sulfur dioxide, toxic air pollutants, and particulate matter.

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

The diesel engines powering the emergency generator and firewater pump are subject to 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). This standard requires the engine manufacturers to achieve limits on NOx, VOC, and particulate matter emissions.

The proposed BACT for the combustion turbines and other emission units is summarized in Table 2.11-1. See Appendix A-1 for additional detail on BACT. The proposed BACT would also ensure compliance with federal New Source Performance Standards and emissions standards established by Ecology and the Olympic Region Clean Air Agency (ORCAA).

2.11.2.2 Criteria Pollutant Emissions

Table 2.11-2 summarizes maximum hourly pollutant emission rates based on vendor information and proposed BACT limits. Actual emission rates vary with time and averaging period because of variations in turbine firing rate and ambient temperature; proposed short-term emission rates reflect the maximum emission rate when operating at 60 percent load or greater. Calculated annual emissions were based on the assumption that the combustion turbines and cooling towers operate at capacity every hour of the year.

The auxiliary boiler will combust only natural gas and is mainly used to generate steam to assist in the startup of the steam turbine and layup of the HRSGs when offline. Criteria pollutant emissions summarized in Table 2.11-2 are based on the use of ultra-low-NO_x burners to achieve 9 ppm NOx and good combustion control to achieve 50 ppm CO. SO_2 emissions are based on a mass balance calculation (as discussed for the combustion turbines). PM and VOC emissions are based on AP42 Section 1.4.

A diesel-fueled engine powering a firewater pump will be available to provide pressurized water for fire protection. Another diesel-fueled engine will power an emergency generator. Both engines will meet the low emission limits prescribed by USEPA’s Tier II emission regulations. Ordinarily, the engine will operate only one half hour per week for testing.

The cooling tower is configured in two parallel sets of five cells. The quantity of water released as droplets to the air (the drift rate) is based on 0.0005 percent of the 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. PM emissions from the cooling tower shown in Table 2.11-2 are based on the assumption that water throughput (gallons per minute) is maximized in all cooling tower cells.

TABLE 2.11-1
BACT SUMMARY

Pollutant	Combustion Turbines		Boiler		Firewater Pump Engine and Emergency Generator Engine		Cooling Tower	
	Best Available Control Technology	Emission Rate	Best Available Control Technology	Emission Rate	Best Available Control Technology	Emission Rate	Best Available Control Technology	Emission Rate
Nitrogen Dioxide (NO_2)	Dry low NOx combustor with SCR	2 ppmvd	Ultra-low NOx burners	9 ppmvd	PC	No limit proposed	NA	NA
Carbon Monoxide (CO)	Turbine design, PC, oxidation catalyst	2 ppmvd	Boiler design, PC	50 ppmvd	PC	No limit proposed	NA	NA
Sulfur Dioxide (SO_2)	Natural gas	1 ppmvd	Natural gas	No limit proposed	0.05% Sulfur fuel	No limit proposed	NA	NA
Particulate Matter (PM_{10})	Natural gas, proper combustion	19 lb/hr/HRSG	Natural gas	No limit proposed	PC	No limit proposed	High efficiency drift eliminators	0.0005% drift rate
Volatile Organic Compounds (VOCs)	Combustion control, oxidation catalyst	1 ppmvd at 100% load, 3 ppmvd at 60% load	Natural gas	No limit proposed	PC	No limit proposed	NA	NA
Ammonia (NH_3)	Proper SCR Operation	5 ppmvd	NA	NA	NA	NA	NA	NA

Note: All proposed concentrations at 15% oxygenA cooling tower would be used 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.
NA = not applicable
PC = proper combustion

TABLE 2.11-2
MAXIMUM HOURLY EMISSIONS (POUNDS)

	NOx	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC
Both CTs/HRSGs	40	24.4	28.3	38	9.5	70
Auxiliary boiler	0.32	1.08	0.17	0.15	0.15	0.12
Diesel generator	3.95	3.45	0.0073	0.20	0.17	3.95
Fire water pump engine	1.36	1.18	0.0033	0.18	0.15	1.36
Cooling Tower	NA	NA	NA	0.79	0.8	NA

Maximum Total	45.6	30.1	28.5	39.3	10.8	12.4

Annual emissions (typically expressed as tons per year or tpy) depend on how many hours each unit operates and the unit's operating rate during those periods. Table 2.11-3 presents annual emissions for two scenarios: continuous operation and daily start up and shut down. First, it presents mass emissions assuming the combustion turbines operate every hour of the year in the operating mode with the highest emissions; this is with the combustion turbines operating at 100 percent load with duct burners for all pollutants except VOCs, which are highest at 60 percent load.

TABLE 2.11-3
UNITS 3 AND 4 ANNUAL CRITERIA POLLUTANT EMISSIONS (TONS)

	NO_x	CO	SO_2	$PM_{10}/PM_{2.5}$	VOC
Annual emissions with continuous CT operation					
Maximum Combustion Turbines[a] Scenario	175	107	62.8	166/41.6	51.5
Auxiliary Boiler[b]	0.40	1.4	0.21	0.18.0.046	0.15
Emergency Generator[c]	0.0010	0.021	0.0026	0.000044/ 0.000015	0.0000018
Firewater Pump Engine[c]	0.00034	0.0071	0.00088	0.000020/ 0.0000067	0.00000083
Cooling Tower[d]	--	--	--	3.5/3.5	--
Total Emissions	176	108	63.0	170/45.1	51.7
Annual emissions with worst case startup and/or shutdown schedule					
Combustion Turbines	166	450	43.7	116/29	52.9
Auxiliary Boiler	0.40	1.4	0.21	0.18/0.046	0.15
Emergency Generator	0.0010	0.021	0.0026	0.000044/ 0.000015	0.0000018
Firewater Pump Engine	0.00034	0.0071	0.00088	0.000020/ 0.0000067	0.00000083
Cooling Tower	--	--	--	3.5/3.5	--
Total Emissions	166	451	43.9	120/32.5	53.1

a. Combined emission rates for both combustion turbine units.
b. 2,500 hours of operation per year.
c. Maximum of 12 hours of operation for maintenance and testing.
d. Total for 10 cooling tower cells.

Although conservative, the auxiliary boiler emissions are based on the assumption that the boiler will operate at full load operation for every hour of the year. This assumption is very conservative and is likely to significantly overstate the actual emissions. Annual emissions from the two diesel engines are based on the assumption they are each tested half an hour per week.

Annual PM_{10} emissions from the cooling towers are based on the assumption that the water flow rate is maximized in each cell every hour of the year. In practice, fans may be turned off when cooling requirements are reduced. Without forced airflow through the cell, drift is reduced significantly.

In consideration of the potential operating mode with frequent startups and shutdowns, Table 2.11-3 also presents emissions assuming the CTs start up and shutdown every day. For this evaluation, it is assumed that the combustion turbines operate 16 hours each day at full load with duct burners and are shutdown for the remaining portion of the day that is not devoted to startup and shutdown. Emissions associated with the auxiliary boiler, diesel engines, and the cooling tower are assumed the same as the continuous operation scenario.

Table 2.11-3 indicates that daily startups would substantially increase annual CO emissions and slightly increase VOC emissions, but would reduce NOx, SO_2, and PM emissions. As noted in Section 5.1.3, predicted CO concentrations during startup are still well below the ambient air quality standards under the daily startup scenario. Details regarding the nature of the facility's emission units and the methods and assumptions incorporated in the development of criteria pollutant emission rates for each source category are provided in Section 5.1.2 and Appendix A-2.

2.11.3 TOXIC AIR POLLUTANTS

Units 3 and 4 will emit compounds deemed hazardous air pollutants (HAPs) by EPA and/or deemed toxic air pollutants (TAPs) by Ecology. TAP and HAP emissions would be reduced by the same process features that control criteria pollutant emissions – the use of gaseous fuels, good combustion controls, and post-combustion control by catalytic oxidation. Emissions of TAPs and HAPs were estimated for both CTs and HRSGs; the auxiliary boiler; the diesel generator; and the emergency firewater pump engine. Emission factors were derived from EPA's AP42 emission factor data for virtually all the TAPs and HAPs emitted by the combustion turbines, the boiler, and the diesel engines.

Aqueous ammonia would be used as the reagent for the SCR control system that would be used to limit NO_x emissions from the combustion turbines. In order to maintain the lowest possible NO_x, emissions levels, it would be necessary to supply ammonia reagent at a rate in excess of that needed to participate in the SCR NO_x reduction reactions. The excess ammonia would escape in the exhaust stream out the stack from each turbine/HRSG train. Grays Harbor Energy LLC has proposed to limit such "ammonia slip" emissions at or below 5 ppmvd at 15% O_2

Sulfuric acid mist emissions depend on the amount of sulfur in the fuel and amount of sulfur dioxide converted to sulfur trioxide during fuel combustion. Combustion turbine emissions of this compound were calculated based on the measured sulfur content of natural gas passing through the Huntingdon station in British Columbia (the anticipated source of gas) and conversion of 30 percent of the sulfur to SO_3, with subsequent reaction with moisture in the exhaust to form sulfuric acid.

Table 2.11-4 presents estimated emissions of TAPs and HAPs that may be emitted by the Units 3 and 4 emission units. Those TAPs that are emitted in quantities exceeding the corresponding small quantity emission rate (SQER) must be evaluated using dispersion models to assess compliance with acceptable ambient air criteria; the results of that assessment are summarized in Sections 3.2 and 5.1.3. Additional information on calculating TAP and HAP emissions is presented in Appendix A-2.

TABLE 2.11-4
COMPARISON OF TAP EMISSION INCREASES WITH SQERS

Compound	CAS #	Emission Rate			SQER		Modeling Required?
		(lb/hr)	(lb/day)	(lb/yr)	Value	Avg Per	
Acetaldehyde	75-07-0	1.53E-01	3.68E+00	1.33E+03	71	Annual	Yes
Acrolein	107-02-8	2.45E-02	5.87E-01	2.12E+02	0.00789	24-hr	Yes
Ammonia	7664-41-7	3.70E+01	8.87E+02	3.24E+05	9.31	24-hr	Yes
Arsenic	7440-38-2	2.23E-04	5.35E-03	1.92E+00	0.0581	Annual	Yes
Benzene	71-43-2	4.99E-02	1.20E+00	4.18E+02	6.62	Annual	Yes
Benzo(a)anthracene	56-55-3	5.75E-06	1.38E-04	1.73E-02	1.74	Annual	No
Benzo(a)pyrene	50-32-8	8.34E-03	2.00E-01	7.30E+01	0.174	Annual	Yes
Benzo(b)fluoranthene	205-99-2	2.23E-06	5.34E-05	1.73E-02	1.74	Annual	No
Benzo(k)fluoranthene	207-08-9	2.35E-06	5.64E-05	1.73E-02	1.74	Annual	No
Beryllium	7440-41-7	1.34E-05	3.21E-04	1.15E-01	0.08	Annual	Yes
1,3-Butadiene	106-99-0	1.72E-03	4.12E-02	1.43E+01	1.13	Annual	Yes
Cadmium	7440-43-9	1.23E-03	2.94E-02	1.05E+01	0.0457	Annual	Yes
Carbon Monoxide	630-08-0	3.01E+01	7.22E+02	2.16E+05	50.4	1-hr	No
Chromium (hexavalent)	18540-29-9	6.24E-05	1.50E-03	5.37E-01	0.00128	Annual	Yes
Chrysene	218-01-9	2.79E-06	6.70E-05	1.73E-02	17.4	Annual	No
Cobalt	7440-48-4	9.36E-05	2.25E-03	8.05E-01	0.013	24-hr	No
Copper	7440-50-8	9.47E-04	2.27E-02	8.15E+00	0.219	1-hr	No
Dibenzo(a,h)anthracene	53-70-3	2.64E-06	6.32E-05	1.15E-02	0.16	Annual	No
Dichlorobenzene	106-46-7	1.34E-03	3.21E-02	1.15E+01	17.4	Annual	No
Diesel Engine Particulate	DEP	3.78E-01	9.08E+00	4.54E+00	0.639	Annual	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	1.78E-05	4.28E-04	1.53E-01	0.00271	Annual	Yes
Ethyl benzene	100-41-4	1.21E-01	2.91E+00	1.06E+03	76.8	Annual	Yes
Formaldehyde	50-00-0	4.90E-01	1.18E+01	4.25E+03	32	Annual	Yes
Hexane	110-54-3	2.01E+00	4.82E+01	1.73E+04	92	24-hr	No
Indeno(1,2,3-cd)pyrene	193-39-5	2.84E-06	6.82E-05	1.73E-02	1.74	Annual	No
Manganese	7439-96-5	4.24E-04	1.02E-02	3.64E+00	0.00526	24-hr	Yes
Mercury	7439-97-6	2.90E-04	6.96E-03	2.49E+00	0.0118	24-hr	No
3-Methylchloranthrene	56-49-5	2.01E-06	4.82E-05	1.73E-02	0.0305	Annual	No
Naphthalene	91-20-3	5.79E-03	1.39E-01	4.90E+01	5.64	Annual	Yes
Nitrogen Dioxide	10102-44-0	4.56E+01	1.10E+03	3.51E+05	1.03	1-hr	Yes
Propylene	115-07-1	5.74E-04	1.38E-02	6.89E-03	394	24-hr	No
Propylene Oxide	75-56-9	1.10E-01	2.64E+00	9.62E+02	51.8	Annual	Yes
Selenium	7784-49-2	2.68E-05	6.42E-04	2.30E-01	2.63	24-hr	No
Sulfur Dioxide	7446-09-5	2.85E+01	6.84E+02	1.26E+05	1.45	1-hr	Yes
Sulfuric acid	7664-93-9	1.44E+01	3.47E+02	1.27E+05	0.131	24-hr	Yes
Toluene	108-88-3	4.97E-01	1.19E+01	4.35E+03	657	24-hr	No
Vanadium	7440-62-2	2.56E-03	6.15E-02	2.20E+01	0.0263	24-hr	Yes
Xylenes	1330-20-7	2.43E-01	5.83E+00	2.12E+03	29	24-hr	No

Note: Small Quantity Emission Rates are defined in WAC 173-460-150

2.11.4 GREENHOUSE GAS EMISSIONS

Units 3 and 4 will emit pollutants considered greenhouse gases (GHGs). The principal GHGs are carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), perfluorocarbons (PFCs), chlorofluorocarbons (CFCs), and sulfur hexafluoride (SF_6). The "greenhouse effect" refers to the "trapping" of solar radiation: analogous to a greenhouse, greenhouse gases impede re-radiation of solar energy from the earth's surface more efficiently than they impede incoming solar radiation.

The degree to which the various greenhouse gases are believed to contribute to global warming differ significantly. Experts agree that CO_2 released by fossil fuel combustion is the largest single source contributing to GHG, accounting for one-third to more than half of the total.

CO_2 emissions result from many sources, including household activities, transportation, and industrial processes. As indicated in Table 2.11-5, the largest sources of CO_2 emissions in the United States are electrical generation and transportation. Figure 2.11-1 shows the primary sources of CO_2 emissions in Washington.

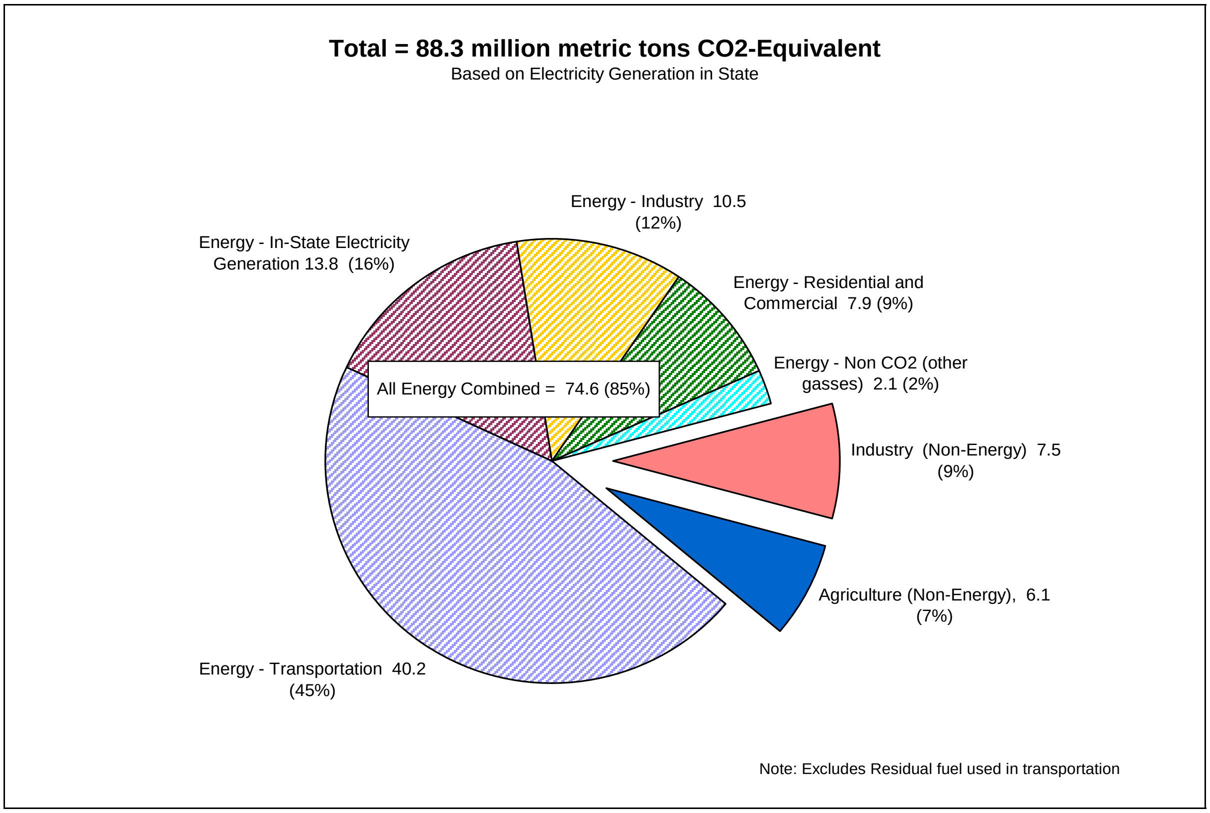
TABLE 2.11-5
CO_2 EMISSIONS FROM FOSSIL FUEL COMBUSTION BY END-USE SECTOR (TG CO_2 EQ.)

End-Use Sector	1990	1995	2000	2005	2007
Transportation	1,487.5	1,601.7	1,803.7	1,886.2	1,892.2
Combustion	1,484.5	1,598.7	1,800.3	1,881.5	1,887.4
Electricity	3.0	3.0	3.4	4.7	4.8
Industrial	1,516.8	1,575.5	1,629.6	1,558.5	1,553.4
Combustion	834.2	862.6	844.6	828.0	845.4
Electricity	682.6	712.9	785.0	730.5	708.0
Residential	927.1	993.3	1,128.2	1,207.2	1,198.0
Combustion	337.7	354.4	370.4	358.0	340.6
Electricity	589.6	638.8	757.9	849.2	857.4
Commercial	749.2	808.5	963.8	1,018.4	1,041.4
Combustion	214.5	224.4	226.9	221.8	214.4
Electricity	534.7	584.1	736.8	796.6	827.1
U.S. Territories	28.3	35.0	36.2	53.2	50.8
Total	**4,708.9**	**5013.9**	**5,561.5**	**5,723.5**	**5,735.8**
Electricity Generation	**1,809.7**	**1.938.9**	**2,283.2**	**2,381.0**	**2,397.2**

Source: USEPA (2009)

Fossil fuel-fired electrical generation is a substantial source of CO_2 emissions both nationwide and in Washington. However, the rate of CO_2 emissions varies considerably with the fuel and technology used. Table 2.11-6 shows the typical rate of CO_2 emitted per kilowatt hour (kWh) of electricity generated from various types of generating facilities. As discussed below, Units 3 and 4 will be substantially more efficient than these typical generating facilities.

The proposed addition of Units 3 and 4 utilizes state of the art technology to improve efficiency and minimize all emissions, including CO_2. Based on the rated fuel energy input capacity of the combustion turbines (and duct burners), the two turbines operating at maximum generating capacity (at 59^{o}F) would emit approximately 233 metric tons (tonnes) of CO_2 per hour.



Source: CTED (2007)

Figure 2.11-1
All Greenhouse Gas Emissions in Washington for 2004 (preliminary estimate)

TABLE 2.11-6
TYPICAL CO_2 EMISSION FACTORS FOR ELECTRICAL GENERATING STATIONS

Generating Station Type	CO_2 Emission Factor (lbs CO_2 per kWh)
Natural gas, combined cycle combustion turbine	0.87
Natural gas, conventional gas-fired boiler	1.32
Fuel oil, conventional oil-fired boiler	1.97
Coal, conventional coal-fired boiler	2.10
Nationwide average for electric utility generating stations (1998)	1.34

Source: EFSEC/BPA (2004)

2.11.5 GHG OFFSET PROPOSAL

The State of Washington has enacted two statutes that address greenhouse gas emissions from proposed generating facilities. The first, chapter 80.70 RCW, imposes carbon dioxide mitigation obligations on new fossil-fueled thermal electric generation facilities. The second, chapter 80.80 RCW, requires that new baseline electric generation facilities comply with an emissions performance standard for greenhouse gases. EFSEC has established regulations that implement the requirements of these statutes: WAC 463-80 and WAC 463-85. The requirements of these two climate change statutes work “in unison” with each other: “The first requirement is the emissions performance standard under WAC 463-85. Once that standard is met, the requirements of chapters 80.70 RCW and 463-80 WAC are applied." The project will comply with the requirements of both climate change statutes and their associated regulations.

2.11.5.1 Compliance with the Performance Standard in WAC 463-85

Because the project may fall within the statute's definition of a "baseload electric generation facility" and the addition of Units 3 and 4 would be an "upgrade" to the facility, the emissions performance standard of chapter 80.80 RCW and WAC 463-85 may apply. The emission performance standard provides that the project's greenhouse gases emissions not exceed 1,100 pounds of greenhouse gases per MW-hour (MWh) as an annual average (WAC 463-85-130[1]).

The Units 3 and 4 combustion turbines and duct burners would emit at most 782 pounds of greenhouse gases per MWh when operating at maximum load. As a result, the facility would comply with the greenhouse gas emissions performance standard under WAC 463-85-130(4)(a) (compliance may be achieved through the "[u]se of fuels and power plant designs that comply with the emissions performance standard without need for greenhouse gases emissions controls").

2.11.5.2 Compliance with the Mitigation Requirements in WAC 463-80

As a proposal to increase the CO2 emissions of the existing Grays Harbor Facility by more than fifteen person, the carbon mitigation requirements of chapter 80.70 RCW and WAC 463-80 apply to the requested amendement. If Units 3 and 4 operated at their full capacity every hour of the year, carbon dioxide emissions would be 2.04 million tonnes per year (see Appendix A-2 for calculation details). The mitigation quantity outlined in the regulation considers 30 years of operation with a capacity factor of 60 percent, or 36.7 million tonnes. WAC 463-80 requires Grays Harbor Energy LLC to mitigate 20 percent of the mitigation quantity, or approximately 7.34 million tonnes.

Grays Harbor Energy LLC has chosen the "monetary path" outlined in RCW 80.70.020(5) for mitigation. At the current rate of $1.60 per metric ton of carbon dioxide, the required payment is approximately $11.75 million. Grays Harbor Energy LLC currently plans to provide EFSEC with proof of payment to a qualifying organization of the total sum, no later than one hundred twenty dats after the start of commercial operation.

SECTION 2.12 CONSTRUCTION AND OPERATION ACTIVITIES (WAC 463-60-235)

2.12.1 POWER PLANT CONSTRUCTION

2.12.1.1 Construction Schedule and Milestones

Final design and construction of the power plant will be accomplished over a 22-month period. The date of initiation of construction will depend on the needs of the Certificate Holder's customers. Depending on the permitting schedule, construction could begin as early as August 2010. Since the date of initiation of on-site construction activities is not known, the information regarding construction schedules presented below is based on duration of activities over the 22 month on-site construction period.

Figure 2.12-1 identifies the major schedule milestones for design and construction of the power plant and associated facilities. The majority of the site preparation work has been completed already as part of the Grays Harbor Energy Center. Following the engineering and design studies, construction activities will begin with the preparation of the site, which will include final grading and road construction. Site preparation is expected to take three months. Construction activities will generally occur five days per week (Monday through Friday), with a 10-hour work day (7 am to 5 pm).

Site preparation will be followed by the installation of underground utilities and foundation work. As soon as possible after the completion of foundation work, the erection of the combustion and steam turbine generator trains and the heat recovery steam generator will begin. The cooling tower, pumps, transformers, mechanical and electrical and other equipment will be installed next.

2.12.1.2 Construction Workforce

The estimated number of construction workers (craft and non-craft) for Units 3 and 4 is shown by month in Figure 2.12-2 and Table 2.12-1.

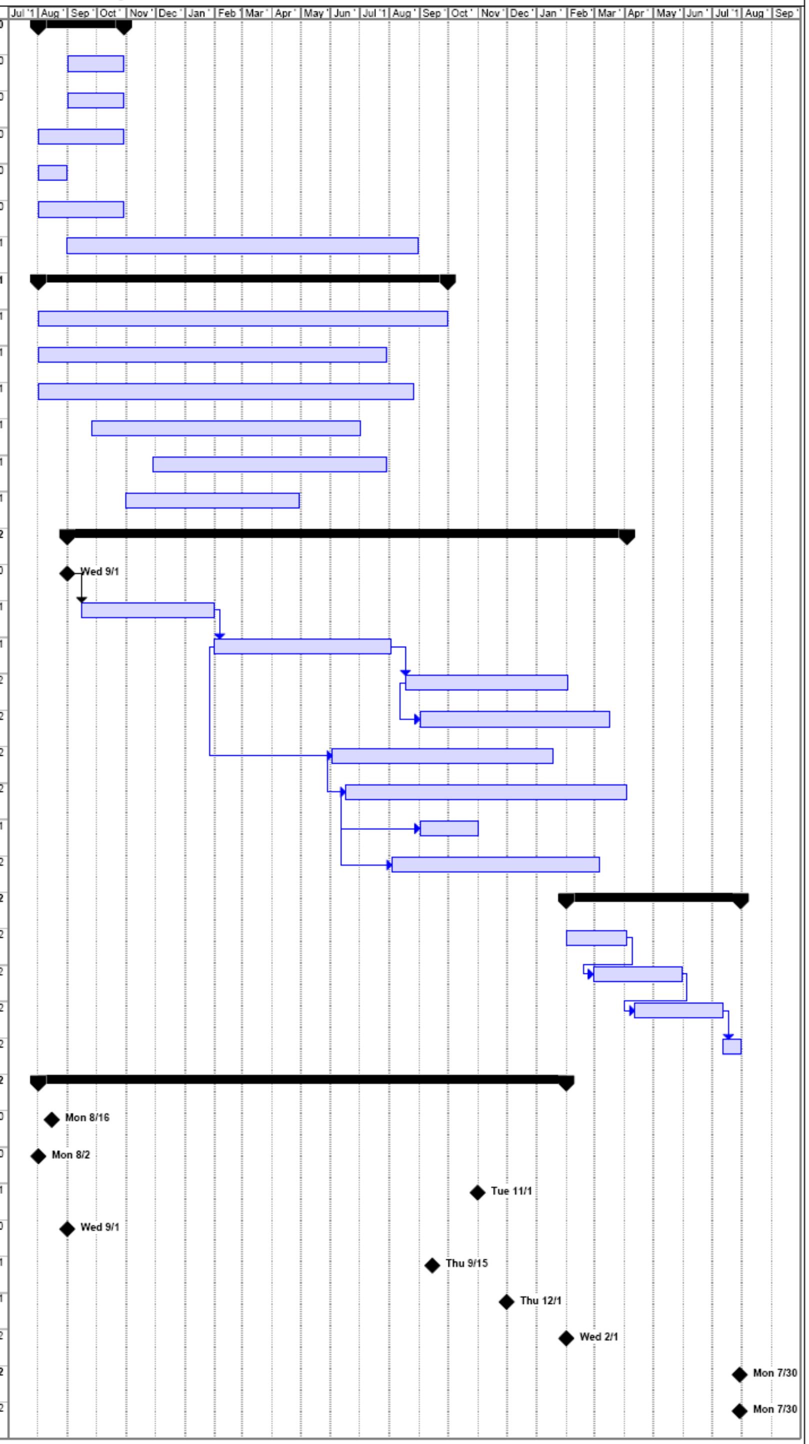
The peak workforce during the 22-month construction period will range from over 400 to over 500 construction personnel from about Month 12 through Month 17 of construction (Figure 2.12-2). During the construction phase there will be craft workers (welders, electricians, etc.) and non-craft workers (engineers, inspectors, etc.).

The types of crafts that will be required for construction include the following: boilermakers, carpenters, cement finishers, electricians, equipment operators and oilers, fire sprinkler installers, laborers, millwrights, painters, pile drivers, pipefitters, plumbers, rodmen, structural steel workers, and welders.

The estimated number of non-craft workers for the construction and start-up phase is based on the sum of project management staff needed by function plus the administrative staff (on-site construction inspectors and project engineers) associated with the anticipated volume of work.

Figure 2.12-1 Construction Schedule

ID	Task Name	Duration	Start	Finish
1	**LNTP ENG & PROC.**	**65 days**	**Mon 8/2/10**	**Fri 10/29/10**
2	High Energy Piping	42 days	Thu 9/2/10	Fri 10/29/10
3	Main Transformer Spec	42 days	Thu 9/2/10	Fri 10/29/10
4	HRSGs	65 days	Mon 8/2/10	Fri 10/29/10
5	STG	22 days	Mon 8/2/10	Tue 8/31/10
6	Balance of Equipment Spe	65 days	Mon 8/2/10	Fri 10/29/10
7	DETAILED ENGINEERING	260 days	Wed 9/1/10	Tue 8/30/11
8	**PROCUREMENT**	**305 days**	**Mon 8/2/10**	**Fri 9/30/11**
9	CTG's	305 days	Mon 8/2/10	Fri 9/30/11
10	STG	260 days	Mon 8/2/10	Fri 7/29/11
11	HRSG	280 days	Mon 8/2/10	Fri 8/26/11
12	High Energy Piping	200 days	Mon 9/27/10	Fri 7/1/11
13	Main Transformers (52 wk	175 days	Mon 11/29/10	Fri 7/29/11
14	Balance of Equipment	130 days	Mon 11/1/10	Fri 4/29/11
15	**CONSTRUCTION**	**415 days**	**Wed 9/1/10**	**Tue 4/3/12**
16	Mobilize	0 days	Wed 9/1/10	Wed 9/1/10
17	Site prep/ Piling/ Dewaterin	98 days	Thu 9/16/10	Mon 1/31/11
18	Concrete -- U/G	131 days	Tue 2/1/11	Tue 8/2/11
19	CTG	120 days	Thu 8/18/11	Wed 2/1/12
20	STG	141 days	Fri 9/2/11	Fri 3/16/12
21	HRSG	163 days	Fri 6/3/11	Tue 1/17/12
22	Piping	208 days	Fri 6/17/11	Tue 4/3/12
23	Main Transformer	43 days	Fri 9/2/11	Tue 11/1/11
24	Electrical / I&C	153 days	Thu 8/4/11	Mon 3/5/12
25	**COMMISSIONING**	**129 days**	**Wed 2/1/12**	**Mon 7/30/12**
26	HRSG	45 days	Wed 2/1/12	Tue 4/3/12
27	CTG's	66 days	Wed 2/29/12	Wed 5/30/12
28	STG	66 days	Thu 4/12/12	Thu 7/12/12
29	Performance Testing	12 days	Fri 7/13/12	Mon 7/30/12
30	**OWNER RESPONSIBILITIES**	**392 days**	**Mon 8/2/10**	**Wed 2/1/12**
31	Site Access	0 days	Mon 8/16/10	Mon 8/16/10
32	Air Permit	0 days	Mon 8/2/10	Mon 8/2/10
33	Backfeed Power	0 days	Tue 11/1/11	Tue 11/1/11
34	Water (Construction)	0 days	Wed 9/1/10	Wed 9/1/10
35	Water	0 days	Thu 9/15/11	Thu 9/15/11
36	Fuel	0 days	Thu 12/1/11	Thu 12/1/11
37	Power Export Availability/ S	0 days	Wed 2/1/12	Wed 2/1/12
38	**SUBSTANTIAL COMPLETION**	**0 days**	**Mon 7/30/12**	**Mon 7/30/12**
39	(Commercial Operation)	0 days	Mon 7/30/12	Mon 7/30/12



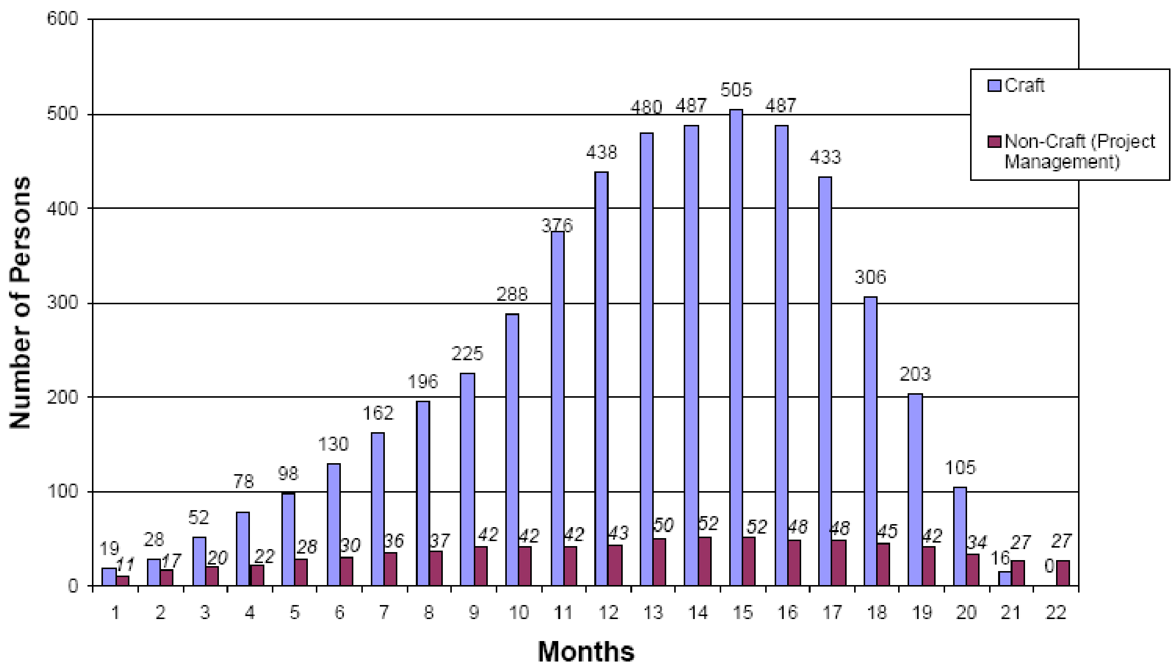
Project: Figure 12.1-1 GHE Constructio
Date: Thu 10/22/09

Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Milestone | Rolled Up Progress | Split | External Tasks | Project Summary | Group By Summary | Deadline

Page 1

Figure 2.12-1 Construction Schedule

Figure 2.12-2 Projected Craft and Staff Requirements for Units 3 and 4



2.12.2 POWER PLANT OPERATION

Operation of Units 3 and 4 would require adding approximately eight employees to the existing staff of 23, for a total of 31 employees. Approximately 20 employees would be working two 12-hour shifts, with a maximum of 31 employees working on site at any time. The operational labor force would include the following positions: plant manager, operations supervisor/engineer, control operators, auxiliary operators, maintenance supervisor, mechanical and electrical technicians, and clerks. Efforts would be made to hire local individuals to staff the project as much as practicable. Major maintenance is expected to take place in Year 6 of operation. During this work, approximately 50 additional people will be on site for 28 days during the day shift.

Initiation of commercial operation for the plant will depend on the needs of the Certificate Holder's customers. If construction is initiated in August of 2010, the earliest anticipated date for the initiation of commercial operation would be approximately mid-2012.

TABLE 2.12-1
POWER PLANT CONSTRUCTION WORKFORCE LOADING

Month	Craft	Non-Craft (Project Management)	Total Staff
1	19	11	30
2	28	17	45
3	52	20	72
4	78	22	100
5	98	28	126
6	130	30	210
7	162	36	198
8	196	37	233
9	225	42	267
10	288	42	330
11	376	42	418
12	438	43	481
13	480	50	530
14	487	52	539
15	505	52	557
16	487	48	535
17	433	48	481
18	306	45	351
19	203	42	245
20	105	34	139
21	16	27	43
22	0	27	27

SECTION 2.13 CONSTRUCTION MANAGEMENT (WAC 463-60-245)

2.13.1 CONSTRUCTION MANAGEMENT—ORGANIZATION

Grays Harbor Energy LLC will contract for the turnkey engineering, procurement and construction (EPC) of Units 3 and 4 with an EPC contractor. Grays Harbor Energy LLC will assemble and maintain a staff of professional engineering and construction personnel to monitor the EPC contractor's performance and to ensure adherence to all contract specifications and requirements throughout the execution of the work.

Organization charts depicting the Certificate Holder's expected oversight organization and the EPC contractor's engineering and construction organization are shown on Figures 2.13-1 and 2.13-2, respectively.

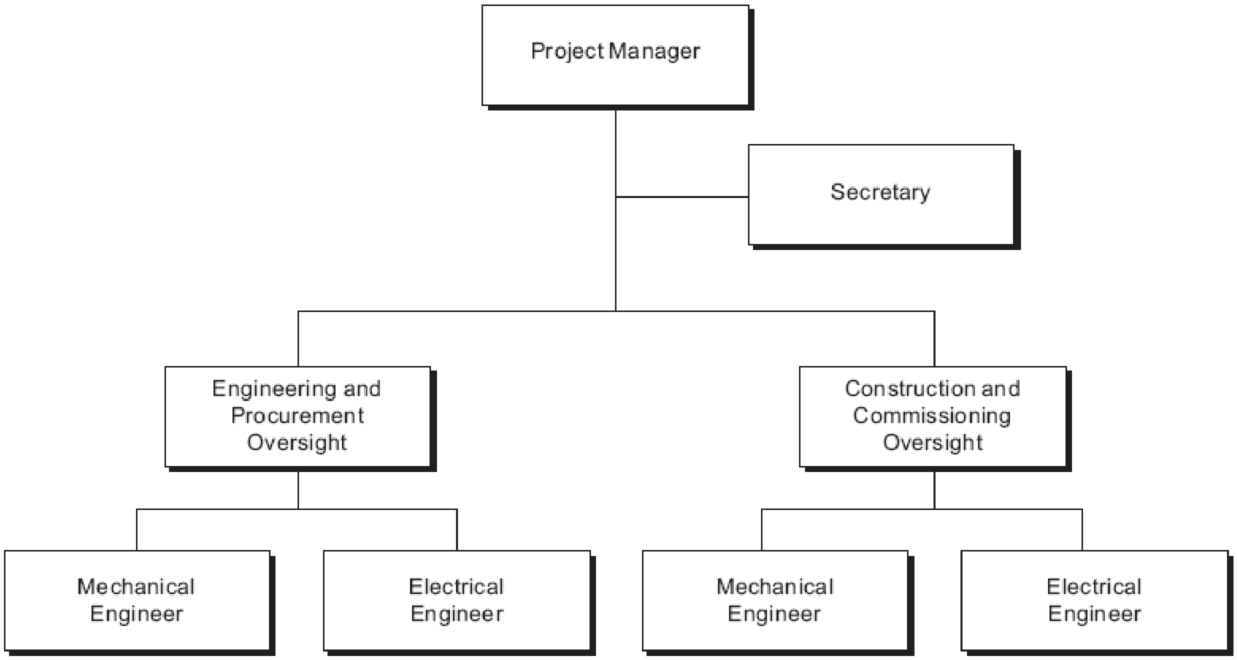


Figure 2.13-1
Grays Harbor Energy LLC Construction Organization Chart

2.13.2 QUALITY ASSURANCE AND QUALITY CONTROL

Grays Harbor Energy LLC will implement QA/QC procedures similar to those implemented during construction of the existing Grays Harbor Energy Center. Grays Harbor Energy LLC will update the existing Project Procedures Manual that describes project activities from the initiation of final design activities through startup of the plant. This document includes a project QA/QC Plan to be used during all phases of the work. The QA/QC Plan will address key aspects, such as vendor shop and field work activities, and the methods each contractor will use to ensure and document that work accomplished for the construction of Units 3 and 4 is of acceptable quality.

Grays Harbor Energy LLC's engineering and construction personnel will periodically audit the EPC contractor, including reviews of documentation and surveillances of field activities to ensure compliance with the project specifications and with the requirements of the QA/QC Plan. For the installation and alignment of major equipment, the acceptance of Grays Harbor Energy LLC's field inspectors will be required prior to final sign-off of Units 3 and 4.

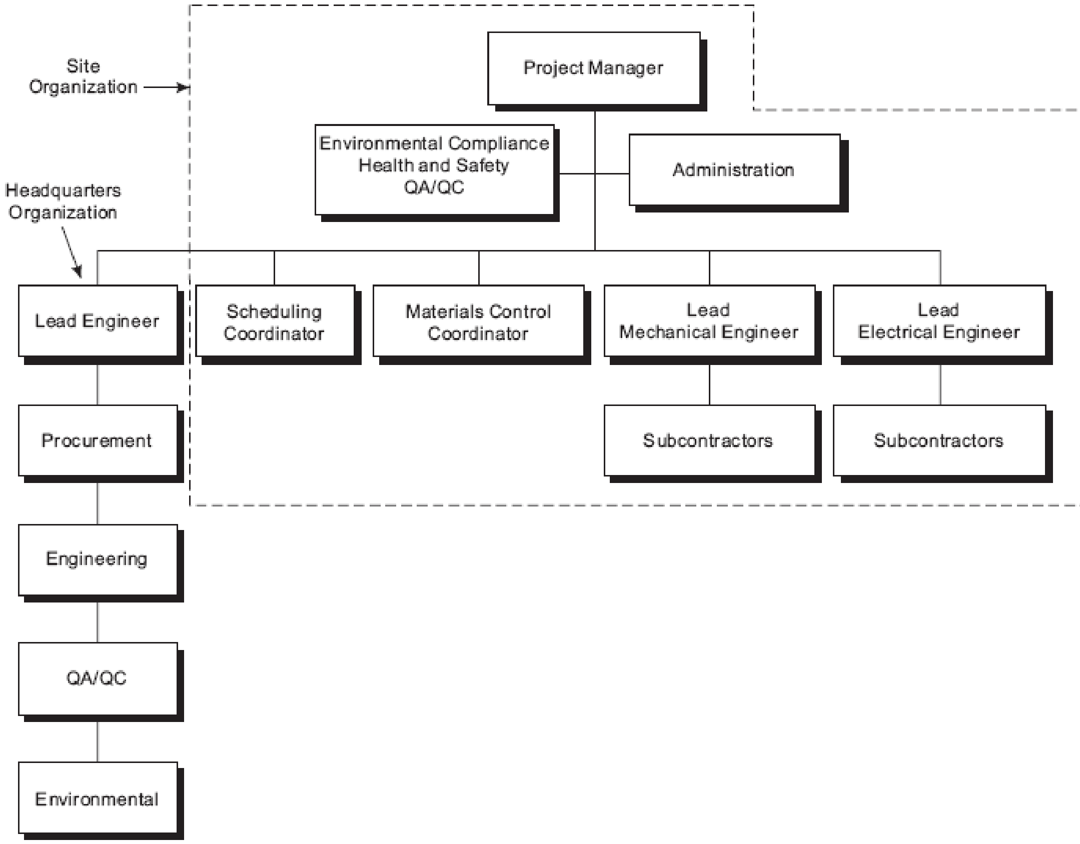


Figure 2.13-2
EPC Contractor Anticipated Organization Chart

2.13.2.1 Environmental Compliance

The Certificate Holder has an active Environmental Protection Control Plan for the Grays Harbor Energy Center that was approved by EFSEC on November 1, 2005. Where appropriate, this plan will be revised to include environmental protection procedures specific to Units 3 and 4.

The Environmental Protection Control Plan covers all construction activities. The Project Manager or the Project Manager's designee will be responsible for complying with the requirements of the Environmental Protection Control Plan. The Certificate Holder will audit the construction of Units 3 and 4 for environmental compliance, including periodic reviews of documentation and surveillance of field activities, as follows:

- Review erosion control plan
- Review spill prevention plan
- Witness construction implementation
- Witness erosion control performance
- Observe spills and cleanup

- Review spill reports

SECTION 2.14 CONSTRUCTION METHODOLOGY (WAC 463-60-255)

WAC 463-60-255 addresses the construction procedures to be used within watercourses, wetlands, and other sensitive areas. There are no watercourses, wetlands, or other sensitive areas on or adjacent to the project site. Therefore, no construction methodology descriptions are required. Construction procedures related to activity in terrestrial areas are addressed in Section 2.3, Construction on Site, WAC 463-60-145.

SECTION 2.15 PROTECTION FROM NATURAL HAZARDS (WAC 463-60-265)

EFSEC has considered the natural hazards associated with the 22-acre project site and has issued an SCA authorizing development of a gas-fired combustion turbine facility on the site. Units 3 and 4 would be constructed on the same site, with an adjacent 10 acres used for temporary construction laydown and access. No additional natural hazards are anticipated.

SECTION 2.16 SECURITY CONCERNS (WAC 463-60-275)

The Grays Harbor Energy Center site is enclosed by a 6-foot-high chain link fence with locking gates that provide ingress and egress; 24-hour security is provided. A fence will be constructed between the existing Grays Harbor Energy Center and the area to be used for Units 3 and 4 for the construction period. The construction fence also will enclose the proposed 10-acre construction laydown and access area.

The Emergency Plan, which was approved by EFSEC on November 1, 2005, applies to all project personnel and provides the guidelines necessary to ensure timely notification and rapid response in the event of emergencies occurring on the property.

SECTION 2.17 STUDY SCHEDULES (WAC 463-60-285)

The Certificate Holder does not plan to perform any additional environmental studies.

SECTION 2.18 POTENTIAL FOR FUTURE ACTIVITIES AT SITE (WAC 463-60-295)

Other than the proposed addition of two units that is the subject of this SCA amendment, the Certificate Holder has no plans for future additions, expansions, or other activities on or adjacent to the project site.

The Satsop Development Park, which is owned by the Grays Harbor PDA, encompasses over 1,600 acres. Because of its size, and the many advantages that the location offers for power production, it is conceivable that other industrial or energy projects will be investigated and proposed for the Satsop Development Park property.

SECTION 2.19 ANALYSIS OF ALTERNATIVES (WAC 463-60-645)

Grays Harbor LLC is proposing to add two units to the existing Grays Harbor Energy Center using the same technology. No alternate sites or technology were considered due to development advantages and minimization of environmental impacts.

SECTION 2.20 PERTINENT FEDERAL, STATE, AND LOCAL REQUIREMENTS (WAC 463-60-685)

Federal, state, and local permits and requirements applicable to the construction and operation of Units 3 and 4 are listed in Table 2.20-1. This table also summarizes the regulatory compliance plans for the project. State and local permits listed are those that would apply to the additional units if the project were not under EFSEC jurisdiction.

TABLE 2.20-1
PERTINENT FEDERAL, STATE, AND LOCAL REQUIREMENTS

Permit or Requirement	Agency/Regulation	Compliance Plan
State Environmental Policy Act	**Grays Harbor County:** RCW 43.21C, 173-802 WAC; project development.	EFSEC performs SEPA compliance as a part of its review of the Certificate Holder's request for an amendment to their SCA.
Air Quality (PSD Permit)	**Ecology:** RCW 70.94, 173-400, 401 WAC; 40 CFR § 52.21Control Requirements for Air Pollutants.	This request for an amendment to the SCA includes a PSD Permit Amendment Application for EFSEC review and approval.
Wastewater Disposal (NPDES)	**Ecology:** Clean Water Act, RCW 90.48, 173-220 WAC, 173-201 WAC, 173-240 WAC; cooling water discharge.	The existing NPDES permit does not place any limit on the quantity of water discharged from the project. The discharge from Units 3 and 4 will comply with the conditions of the existing NPDES permit. It is not anticipated that an amendment to the existing NPDES permit will be required.
Stormwater Discharge (NPDES)	**Ecology:** Clean Water Act, RCW 90.48, 90.50, 90.52, 173-220 WAC; stormwater discharge associated with construction and industrial activities.	The existing NPDES permit authorizes the discharge of stormwater during construction and operations. A SWPPP has been developed as required by the permit. The SWPPP will be modified, if necessary, to include the area used for Units 3 and 4.
Spill Prevention Control and Countermeasures Plan	**Ecology:** 40 CFR 112, RCW 80.50; plan to prevent, control and contain accidental petroleum discharges into surface waters.	The SPCC plan for the Satsop Combustion Turbine/ Grays Harbor Energy Center was approved by EFSEC on November 1, 2005, and applies to Units 3 and 4.
Notification of Dangerous Waste Activities	**Ecology:** 173-303 WAC, RCW 80.50; identification of dangerous waste activities.	An active state identification number has been issued for the Grays Harbor Energy Center. This request for an amendment to the SCA provides EFSEC with information on 1) waste streams, compositions, and volumes, and 2) hazardous waste activities. Stipulations on methods of handling dangerous wastes are expected to be included in the amended SCA issued by EFSEC and are expected to be similar to those included in the existing SCA.
Building Approval	**Grays Harbor County:** County Code 15.4; RCW 80.50; to comply with County Building Code.	Building plans will comply with the Grays Harbor County Building Code. Following current EFSEC requirements, drawings and specifications related to public health and safety will be submitted to Grays Harbor County for review and approval.
Land Use and Zoning Compliance	**Grays Harbor County:** Ordinance 241, County Title 17, RCW 80.50; demonstration of compliance with county land use and zoning ordinances.	As part of the SCA amendment for the Grays Harbor Energy Center, the location of energy facilities at the Grays Harbor Energy site was found to be consistent with the Grays Harbor County Zoning Code. The site was rezoned to I-2 expressly to permit energy facilities.
County Road Permit	Grays Harbor County: County Ordinance	If needed, county road permits will be obtained from Grays Harbor County for hauling of materials to the site. Road access and work in county road right-of-way permits also will be obtained if needed.

CFR Code of Federal Regulations
EFSEC Energy Facility Site Evaluation Council
NPDES National Pollutant Discharge Elimination System
PSD Prevention of Significant Deterioration
RCW Revised Code of Washington
SCA Site Certification Agreement
SEPA State Environmental Policy Act
SPCC Spill Prevention, Control and Countermeasure
SWPPP Stormwater Pollution Prevention Plan
WAC Washington Administrative Code

3.0 NATURAL ENVIRONMENT

SECTION 3.1 EARTH (WAC 463-60-302)

Units 3 and 4 will be constructed on the existing Grays Harbor Energy Center site. EFSEC previously studied the project site and permitted construction and operation of the Grays Harbor Energy Center facility at this location. This section summarizes the information about the geology, soils, topography, unique physical features, and erosion presented in previous applications to EFSEC. With standard and site-specific mitigation measures, only minor impacts on the natural earth environment from the construction and operation of Units 3 and 4 are expected. No new impacts are expected at the existing site from construction or operation of the additional units, and no significant impacts are expected at the adjacent 10-acre construction laydown and access area.

3.1.1 SOILS

Naturally occurring surficial soils have been modified or removed as a result of the prior grading and construction activities at the existing 22-acre project site. The adjacent 10-acre site proposed for construction laydown and access is covered with approximately 5-acres of thinned conifers and 5-acres of grassland/agriculture that is mowed every year.

The subsurface strata and engineering properties of the Helm Creek deposits in the site area have been assessed in conjunction with work completed for nuclear project WNP-3 and the Grays Harbor Energy Center. Site-specific conditions of the project site were investigated by URS (2001). Subsurface conditions were investigated by drilling nine borings, advancing 27 electric cone penetrometer probes, and excavating five test pits. Borings were drilled to depths of 60 to 120 feet, the cone probes were pushed to depths of 40 to 133 feet, and the test pits were excavated to depths of 10 to 12 feet.

Generally, the soils encountered at the site consisted of up to approximately 75 feet of alluvial soils (interpreted as Helm Creek deposits) overlying decomposed sandstone from the Astoria Formation. The engineering properties of these strata are summarized in Table 3.1-1.

TABLE 3.1-1
SUMMARY OF SOIL CONDITIONS AND DESIGN PARAMETERS

Item	Stratum 1 Silt	Recompact Stratum 1 Silt	Stratum 2 Silty Sand Sandy Silt	Stratum 3 Gravelly Sand	Stratum 4 Silty Sand
Average Thickness (ft)	10		20	40	40+
Typical Uncorrected N-values (blows per ft)	2 to 5		3 to 10	14 to 35	20 to 40
Typical Cone Tip Resistance (tons per ft^2)	6 to 10		30 to 60	100 to 200	50 to 100
Ave. Shear Wave Velocity (ft/second)[a]	640	680	870	1,590	1,320
Ave. Compr. Wave Velocity (ft/second)[b]	1,560	1,700	1,800	3,300	2,750
Total Unit Weight (pounds per cubic ft)	110	110	110	130	120
Friction Angle (degrees)	0	0	0	40	36
Cohesion (pounds per ft^2)	900	1,200	1,200	0	50
Dynamic Elastic Modulus (kips per ft^2)[c]	3,800	4,400	7,000	27,000	17,000
Static Elastic Modulus (kips per ft^2)	300	3,20	250	800	600
Dynamic Shear Modulus (kips per ft^2)[c]	1,400	1,600	2,600	10,200	6,500
Poisson's Ratio	0.4	0.4	0.35	0.35	0.35
Active Earth Pressure Coefficient	0.36	0.36	0.31		
At-Rest Earth Pressure Coefficient	0.53	0.53	0.47		
Passive Earth Pressure Coefficient	2.7	2.7	3.2		
Soil-Concrete Friction Coefficient	0.3	0.3	0.3		
California Bearing Ratio	5	6			
Compression Index[d]	0.1	0.1	0.08		
Coefficient of Consolidation (ft^2/day)	1.5	1.5	8.5		
Permeability (cm/sec)	10^{-5}	10^{-5}	10^{-3}		
Thermal Resistivity (^{o}C·cm/W)[e]	50	50	46		

Source: URS (2001)

Values listed above generally represent average to the slightly conservative side of average values based on interpretation of available data. Natural variability of soil conditions and parameters are expected to occur throughout the site.

The water table is interpreted to be at a depth of at least 70 feet.

a. Values are measured, except for Recompacted Stratum 1

b. Values are estimated

c. Values apply to a shear strain level of approximately 10^{-4} percent

d. From a percent strain versus log of applied load curve

e. Degrees Centigrade multiplied by centimeters divided by Watts

The specific description of each soil unit, proceeding downward from the ground surface, is as follows:

- ***Gravel Surfacing.*** The site is covered with a gravel fill approximately 1.5 to 2.5 feet in thickness. The gravel is subrounded, reasonably well graded and contains some silt and sand as well as cobbles. At the base of this fill cover is a geotextile.
- ***Stratum 1 – Reddish Brown Medium Stiff to Stiff SILT.*** This soil layer is typically 5 to 12 feet thick, and medium stiff to stiff in character based on N-values, cone tip resistances, pocket penetrometer test values, and unconfined compression test values. Other laboratory tests indicate that this silt is moderately to highly plastic (liquid limit of 54) and moderately compressible. Moisture content was usually in the range of 38 to 44 percent.
- ***Stratum 2 – Yellowish Brown Silty SAND to Sandy SILT.*** This soil layer grades between a fine sand and a silt, and typically exhibits the character of a fine-grained soil. The layer is

only 4 to 10 feet thick along the western 200 feet of the site, but is typically 20 to 30 feet thick elsewhere. The soil would be characterized as stiff based on N-values and cone tip resistance values. Laboratory tests indicate that the fines content of the layer ranges from 39 to 65 percent for the samples tested. The fines appear to be non-plastic. Consolidation tests indicate that the soil is moderately compressible but drains quickly. High natural moisture contents in the range of 40 to 50 percent were measured.

- ***Stratum 3 – Multi-colored Medium Dense to Dense Gravelly SAND.*** This layer typically consists of well-graded sand with 15 to 50 percent gravel and 15 to 25 percent fines. The apparently re-worked sediments show color variations that include red, green, gray, brown and white. This layer is at least 25 feet thick, and more typically the thickness exceeds 35 feet. The N-values and cone tip resistance values suggest that the layer is medium dense to dense in character.
- ***Stratum 4 – Brown to Grayish Brown Silty SAND.*** This layer is interpreted to be a residual soil derived from the Astoria Sandstone formation. It is primarily silty sand, but contains occasional zones that are primarily silt. N-values and cone tip resistance values suggest that the soil is dense in character. The last sample collected in boring B-3, at a depth of 111 feet below ground surface (bgs), appeared to be the weathered top of the Astoria sandstone.

3.1.2 TOPOGRAPHY

3.1.2.1 Existing Conditions

The Grays Harbor Energy Center site is located on a flat terrace above the Chehalis River in a region characterized by finely dissected uplands cut by the valley of the Chehalis River. The terrace lies at an elevation of approximately 305 feet (93 meters) above mean sea level (msl), 300 feet (91 meters) above the Chehalis River. The gravel-covered ground surface slopes gently downward to the west and north, with a total topographic relief across the site of about 30 feet. The low point of the site is at approximately 284 feet above msl at the northwest corner. From the site, elevation drops 240 feet (73 meters) to the next lower river terrace in a steep, but short slope to the north. West of the site, approximately 3,000 feet (315 meters), the terrace drops to river level in a steep river cutbank.

The land surface rises to the south of the site in a finely dissected drainage pattern to a topographic high of over 1,760 feet (536 meters) above msl at Minot Peak, 6 miles (10 km) to the southeast. Fuller Creek, less than 1,500 feet (450 meters) southeast, is the nearest surface drainage. It flows northeast to the Chehalis River in a 100-foot (30-meter) deep valley.

3.1.2.2 Impacts

The finished grade of the Grays Harbor Energy Center site will be approximately 305 feet above msl. Therefore, construction of Units 3 and 4 will require some cutting and filling that will have an insignificant impact on topography. The amount of material to be removed and replaced is approximately 80,000 cubic yards.

3.1.2.3 Mitigation Measures

No mitigation measures are necessary.

3.1.3 UNIQUE PHYSICAL FEATURES

There are no unusual or unique geological or physical features in the area that could potentially be affected by the construction of Units 3 and 4.

3.1.4 EROSION/ENLARGEMENT OF LAND AREA (ACCRETION)

3.1.4.1 Existing Conditions

As part of the soil surveys of Grays Harbor County, the Washington State Department of Natural Resources (DNR) conducted a survey that evaluated the erosion potential in an area that includes both the existing 22-acre site and the adjacent 10-acre site proposed for construction laydown and access. The rating for erosion potential is based on the interaction of the following conditions:

- Soil properties, including texture, structure, and porosity
- Rainfall rate and storm intensity
- Slope

The soil property is represented in the commonly used Universal Soil Loss Equation as the K factor. The larger the K factor of a soil, the higher the potential for erosion, given that all other factors remain constant.

Rainfall rate is readily available from government agencies and slope is a function of the rise in elevation over a horizontal distance expressed as a percentage. Slopes greater than 15 percent are classified as having high potential for erosion, slopes from 5 to 15 percent have medium potential, and less than 5 percent have a low potential.

The soils underlying the proposed plant site and in the immediate vicinity of the site have been assigned K factors of between 0.15 to 0.32 at the depths expected to be disturbed during construction (USDA SCS 1986). These values correspond to a high potential for soil erosion. The slope at the project site itself has a rating of 1 (low); slopes adjacent to Fuller Creek to the east have a slope rating of 3 (high). It is anticipated that the majority of disturbance during the construction and operation of Units 3 and 4 will occur on the relatively flat bench away from the creek.

3.1.4.2 Impacts

The Certificate Holder has an EFSEC-approved Erosion Control Plan (CTP-2-01 dated November 1, 2005) for the Grays Harbor Energy Center which covers the entire site, including the area proposed for Units 3 and 4. This plan is designed to prevent and/or minimize the potential for erosion. Implementation of the plan will result in minimal, if, any erosion impacts.

3.1.4.3 Mitigation Measures

No additional mitigation measures are warranted beyond implementation of the EFSEC-approved Erosion Control Plan.

SECTION 3.2 AIR (WAC 463-60-312)

Air quality in Washington is regulated by several agencies. In the project area, the Olympic Region Clean Air Agency (ORCAA) is typically the local authority for air quality permitting of industrial sources, and permits minor sources through the Notice of Construction (NOC) permit process. The Department of Ecology (Ecology) generally retains the authority for air quality permitting of major sources in attainment areas through the Prevention of Significant Deterioration (PSD) permit process. The United States Environmental Protection Agency (USEPA) also has a role in the PSD process and in ensuring all states have plans in place to maintain compliance with ambient air quality standards.

The Energy Facility Site Evaluation Council (EFSEC) has jurisdiction over power plants capable of generating 350 megawatt (MW) or more. Because the generation capacity of the existing Grays Harbor Energy Center exceeds this threshold, EFSEC is the responsible permitting authority for this facility. EFSEC has adopted virtually all air quality regulations established by Ecology that apply to facilities such as the Grays Harbor Energy Center. Consequently, this discussion may refer to regulations established by Ecology, ORCAA, or USEPA even though EFSEC is the permitting authority for this project.

The distinction between emission rates and ambient concentrations is important in the review of air quality issues. Emission regulations limit the amount of a particular air pollutant that can be emitted from a stack or facility (e.g., ten pounds per hour [lbs/hr] of particulate matter). Emission rates and regulations are discussed in section 2.11. Ambient air quality standards limit concentrations of certain air pollutants (in parts per million [ppm] or millionths of a gram per cubic meter of air [$\mu g/m^3$]) in the outdoor (ambient) air. The impact of Unit 3 and 4 emissions on ambient air quality are discussed in this section. More detail on both topics can be found in Section 5.1.

The Air Quality Impact Analysis developed as part of the PSD permit application in Section 5.1 of this Application determined that worst-case emissions of criteria pollutants[1] from Units 3 and 4 would result in ambient concentrations far below Washington and National Ambient Air Quality Standards (WAAQS and NAAQS), and well within allowable PSD increments for Class I and Class II areas. Calculated toxic air pollutant (TAP) concentrations attributable to Units 3 and 4 also meet Washington ambient criteria.

[1] Criteria pollutants are the six common pollutants regulated by the USEPA: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). Because ozone is generally not directly emitted by sources, volatile organic compounds (VOCs) are used as a surrogate for ozone.

3.2.1 APPLICABLE AIR REGULATIONS

3.2.1.1 Ambient Air Quality Standards

The ambient air quality standards established by USEPA and Ecology are summarized in Table 3.2-1. Some of the pollutants are subject to both "primary" and "secondary" NAAQS. Primary standards are designed to protect human health with a margin of safety. Secondary standards are established to protect the public welfare from any known or anticipated adverse effects associated with these pollutants, such as soiling, corrosion, or damage to vegetation.

TABLE 3.2-1
AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENTS

Pollutant	National Ambient Air Quality Standards		Washington	Class I PSD Increments	Class II PSD Increments
	National Primary	National Secondary			
Total Suspended Particulate (TSP)					
Annual Geo. Mean (μg/m^3)			60		
24-hour Average (μg/m^3)			150		
Inhalable Particulate (PM_{10})					
Annual Arith. Mean (μg/m^3)	note a		50	4	17
24-hour Average (μg/m^3)	150[b]	150[b]	150[b]	8	30
Fine Particulate ($PM_{2.5}$)					
Annual Arith. Mean (μg/m^3)	15[c]	15[c]			
24-hour Average (μg/m^3)	35[d]	35[d]			
Sulfur Dioxide (SO_2)					
Annual Average (ppm)	0.03		0.02	2 μg/m^3	20 μg/m^3
24-hour Average (ppm)	0.14[b]		0.10[b]	5 μg/m^3	91 μg/m^3
3-hour Average (ppm)		0.5[b]		25 μg/m^3	512 μg/m^3
1-hour Average (ppm)			0.40[b]		
Carbon Monoxide (CO)					
8-hour Average (ppm)	9[b]		9[b]		
1-hour Average (ppm)	35[b]		35[b]		
Ozone (O_3)					
8-hour Average (ppm)	0.075[e]	0.075[e]			
1-hour Average (ppm)	note f	note f	0.12[g]		
Nitrogen Dioxide (NO_2)					
Annual Average (ppm)	0.053	0.053	0.05	2.5 μg/m^3	25 μg/m^3
Lead (Pb)					
Quarterly Average (μg/m^3)	1.5	1.5			

Sources include: NAAQS (40 CFR 50), WAAQS (Chapters 173-470, 474, and 475 WAC), and PSD Increments (40 CFR 51.166).
μg/m3 = micrograms per cubic meter; ppm = parts per million
a. Federal annual PM10 standard revoked as of September 21, 2006
b. Not to be exceeded more than once per year.
c. Based on the 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors
d. Based on the 3-year average of the 98th percentile of 24-hour PM2.5 concentrations at each monitor within an area.
e. Based on the 3-year average of the annual fourth-highest daily maximum 8-hour ozone concentration at each monitor.
f. Federal 1-hour ozone standard was revoked in all areas except 14 remaining nonattainment areas on June 15, 2005 but Washington has retained the standard.
g. Not to be exceeded on more than 1 day per calendar year as provided in Chapter 173-475 WAC.

3.2.1.2 Toxic Air Pollutant Regulations

Washington regulations concerning emissions of Toxic Air Pollutants (TAPs) from new and modified air pollution sources are in Chapter 173-460 of the WAC. These regulations identify Small Quality Emission Rates (SQERs) for TAPs. If the SQER is exceeded after applying the best available control technology, dispersion modeling is performed to evaluate potential ambient air quality impacts from TAP emissions.

Washington regulations also establishe outdoor exposure levels (called Acceptable Source Impact Levels, or ASILs) for more than 300 substances that are conservative in their protection of human health. Modeled ambient air quality impacts of TAPs are compared to these ASILs. If modeled concentrations are less than the ASILs, a permit can be granted. If ASILs are exceeded, the applicant must revise the project or submit a health risk assessment demonstrating that TAP emissions from the source are sufficiently low to protect human health.

Tables 2.11-4 and 5.1-15 compare TAP emission rates for Units 3 and 4 with the SQERs, and show which TAPs require modeling analysis. The results of the modeling analysis are presented in section 3.2.1.8.

3.2.1.3 Notice of Construction and Application for Approval

State law requires an NOC permit application for new air contaminant sources in Washington, which provides a description of the facility and an inventory of pollutant emissions and controls. The reviewing agency considers whether BACT has been employed to proposed emission sources and evaluates ambient concentrations resulting from the proposed emissions to ensure compliance with ambient air quality standards. Chapter 5.1 of this Application serves as a single combined NOC and PSD permit application. When both an NOC approval and PSD permit are required, the NOC approval addresses those criteria pollutants emitted in quantities less than PSD significant emissions rates and other non-criteria pollutants (i.e., TAPs) that are not subject to PSD review.

3.2.1.4 Prevention of Significant Deterioration (PSD)

The PSD regulations were established by USEPA to ensure that new or expanded sources do not cause the air quality in areas that currently meet ambient standards (i.e., attainment areas) to deteriorate significantly. These regulations set PSD Increments that limit the increases in sulfur dioxide (SO_2), nitrogen dioxide (NO_2) and particulate matter (PM_{10}) 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 the project site is the Olympic National Park, which is located about 58 kilometers north of the project site. The area surrounding the proposed project site is designated a Class II area, where less stringent PSD increments apply. Class I and Class II increments are displayed with the ambient standards in Table 3.2-1. No Class III areas have been established in Washington.

The existing Grays Harbor Energy Center is a major source under PSD regulations because its potential emissions exceed the 100 tons per year (tpy) threshold. Once deemed a major source, modifications of the facility also trigger PSD review if the modification results in emission increases exceeding threshold values called Significant Emission Rates. Anticipated annual emissions of nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO2), volatile organic compounds (VOCs), particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to ten microns (PM_{10}) and particulate matter with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$) exceed the significant emission rates that trigger evaluation in the PSD permit. Chapter 5.1 of this document provides the PSD permit application and addresses significant air pollutants associated with the Units 3 and 4.

3.2.2 EXISTING CONDITIONS

3.2.2.1 Existing Air Quality

The USEPA's AirData website (http://www.epa.gov/air/data/info.html) is a database that contains air quality data from monitoring sites across the United States and allows users to collect yearly summarized air quality data for specific monitoring sites. Air quality measurement data were collected for 2005 through 2008 for monitoring sites located in Washington. The data search was narrowed to monitoring sites in Seattle, Yelm, and Anacortes, for CO, NO2, SO2, and ozone. Data collected at Aberdeen and Oakville for $PM_{2.5}$ were obtained from Ecology's website. Previous monitoring on the Grays Harbor Energy site is used to characterize existing PM_{10} and SO_2 concentrations.

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

The monitoring data from the various sites can be used to characterize existing air quality at the site. A summary of these data is presented in Table 3.2-2. All observed pollutant concentrations at these monitoring sites are lower than the NAAQS and WAAQS.

TABLE 3.2-2
AMBIENT AIR QUALITY MONITORING DATA

Pollutant	Averaging Period	Data Source[a]	Maximum Concentration[b] 2005[c]	2006	2007	2008	Average	Ambient Standard[d]
NO_2 (ppm)	Annual	a	0.018	0.018	--	--	0.018	0.05
	Annual	b	0.008	0.006	0.008	0.011	0.008	0.05
CO (ppm)	1 Hour	a	2.7	2.0	1.4	1.2	1.8	35
	8 Hours	a	1.9	1.2	1.0	0.9	1.3	9
SO_2 (ppm)	1 Hour	a	0.042	--	0.031	0.073	0.049	0.4
	3 Hours	a	0.024	--	0.021	0.026	0.024	0.5
	24 Hours	a	0.012	--	0.007	0.011	0.010	0.1
	Annual	a	0.004	--	0.002	0.001	0.002	0.02
	1 Hour	c1	0.006	--	--	--	0.006	0.4
	3 Hours	c1	0.004	--	--	--	0.004	0.5
	24 Hours	c1	0.004	--	--	--	0.004	0.1
	Annual	c1	0.001	--	--	--	0.001	0.02
	1 Hour	c2	0.007	--	--	--	0.007	0.4
	3 Hours	c2	0.006	--	--	--	0.006	0.5
	24 Hours	c2	0.006	--	--	--	0.006	0.1
	Annual	c2	0.001	--	--	--	0.001	0.02
Ozone (ppm)	1 Hour	d	0.070	0.081	0.068	0.075	0.074	0.12[e]
	8 Hours	d	0.059	0.068	0.054	0.060	0.060	0.075[f]
PM_{10} ($\mu g/m^3$)	24 Hours	c1	22.1	--	--	--	22.1	150
	Annual	c1	9.8	--	--	--	9.8	50
	24 Hours	c2	21.6	--	--	--	21.6	150
	Annual	c2	9.0	--	--	--	9.0	50
$PM_{2.5}$[g] ($\mu g/m^3$)	24 Hours	e	--	--	18.3	15.6	17.0	35
	Annual	e	--	--	6.7	6.9	6.8	15
	24 Hours	f	--	--	19.7	14.5	17.1	35
	Annual	f	--	--	6.2	6.2	6.2	15

a. Data sources are as follows:
 a – Seattle, WA (4103 Beacon Hill S)
 b – Anacortes, WA (Casino Drive/North End Site)
 c1 – Grays Harbor Energy Center Site, Station 1, May 2002 – May 2003
 c2 – Grays Harbor Energy Center Site, Station 2, May 2002 – May 2003
 d – Yelm, WA (709 Mill Rd Se for 2005 data, 931 Northern Pacific Road for 2006-2008 data)
 e – Aberdeen, WA (359 N Division St)
 f – Oakville, WA (252 Howanut Dr)
b. From USEPA AIRS database (http://www.epa.gov/air/data/info.html) and Washington Dept. of Ecology website (https://fortress.wa.gov/ecy/enviwa/), both accessed February 2009. PM10 and some SO2 data from monitoring conducted at the Grays Harbor Energy Center site between May 2002 and May 2003.
c. The data for PM10 and some SO2 from monitoring locations c1 and c2 on the Gray Harbor Energy Center site are from the monitoring period between May 2002 and May 2003.
d. The most stringent standard from NAAQS and WAAQS.
e. Federal 1-hour ozone standard was revoked as of June 15, 2005 in all areas except 14 remaining nonattainment areas.
f. Attainment based on 3-year average of the 4th highest daily maximum 8-hour ozone concentration at each monitoring location
g. PM2.5 24-hour average is based on the 98th percentile; the annual standard is based on a three year average.

- NO_2 was monitored in Seattle and Anacortes, where the maximum annual concentrations were less than 36 and 22 percent of the NAAQS, respectively.
- CO was monitored in Seattle, where the maximum concentrations were less than 8 percent of the 1-hour average NAAQS and less than 22 percent of the 8-hour average NAAQS.

- SO_2 was monitored in Seattle for the years 2005, 2007, and 2008 and on the Grays Harbor Energy Center site for a one-year period between May of 2002 and 2003. The maximum concentrations in Seattle and at the project site were less than 20 and 6 percent of the NAAQS, respectively.
- The 4th highest maximum 8-hour ozone concentration monitored in Yelm was about 91 percent of the 8-hour NAAQS. The 2nd highest maximum hourly ozone concentration monitored in Yelm was about 68 percent of the 1-hour NAAQS. PM_{10} concentrations (usually associated with wood smoke, fugitive dust, and combustion sources) were monitored at two locations on the project site for a one-year period between May of 2002 and 2003. Average 24-hour concentrations were less than 15 percent of the NAAQS at both locations. Annual average concentrations were 18 to 20 percent of the NAAQS.
- $PM_{2.5}$ was monitored in Aberdeen and Oakville; each location is approximately 16 miles from the project site. The average of the 98th percentile 24-hour concentration over 2007 and 2008 was 49 percent of the 24-hour NAAQS at both locations. The annual averages at Aberdeen and Oakville were 45 and 41 percent of the NAAQS, respectively.[2]

3.2.2.2 Topography

The project site is located just south of the edge of the broad Chehalis River Valley at an elevation ranging from about 290 to 315 feet above msl. The area south of the plant has terrain higher than 1,200 feet above the site, while the Chehalis River Valley floor is approximately 300 feet below the site. The channeling influences of the valley floor and the larger scale topography act to give the site location a prevailing westerly wind direction. Windroses from an on-site meteorological tower are provided in the modeling protocol attached as Appendix A-3.

3.2.2.3 Climate

The climate of western Washington is dominated by two large-scale influences: the mid-latitude westerly winds and proximity of the Pacific Ocean. Temperature data available from the National Climatic Data Center, measured over a 30-year period in Elma, indicate that monthly temperatures average 51°F, with an average maximum of 67°F, and an average minimum of 34°F. Temperature extremes were recorded ranging from the high 20s°F for the minimum temperatures up to the high 90s°F as the maximum temperatures recorded. Few days below 32°F are recorded for the project area.

Precipitation totals about 60 inches annually, with the wettest months from November to April. Approximately 5 inches of snow falls annually, primarily from December to March. Mean annual mixing heights for the morning hours are approximately 600 meters, while afternoon or evening hour mixing heights are approximately 1,000 meters for the Northwest Pacific Coastal region. Relative humidity ranges from a low of about 50 percent during the summer months to a low of about 70 percent in the winter months.

---

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

3.2.2.4 Meteorology

Representative meteorological data for the project site and vicinity was obtained from a meteorological monitoring station located within the current Grays Harbor Energy Center site boundary. Specific information related to instrumentation, data collection, audits, data recovery, and data validation is provided by monitoring reports prepared by McCulley, Frick, and Gilman, Inc. These reports are included on the compact disc with dispersion modeling files. Figure 3.2-1 presents a windrose summary of wind conditions at the site.

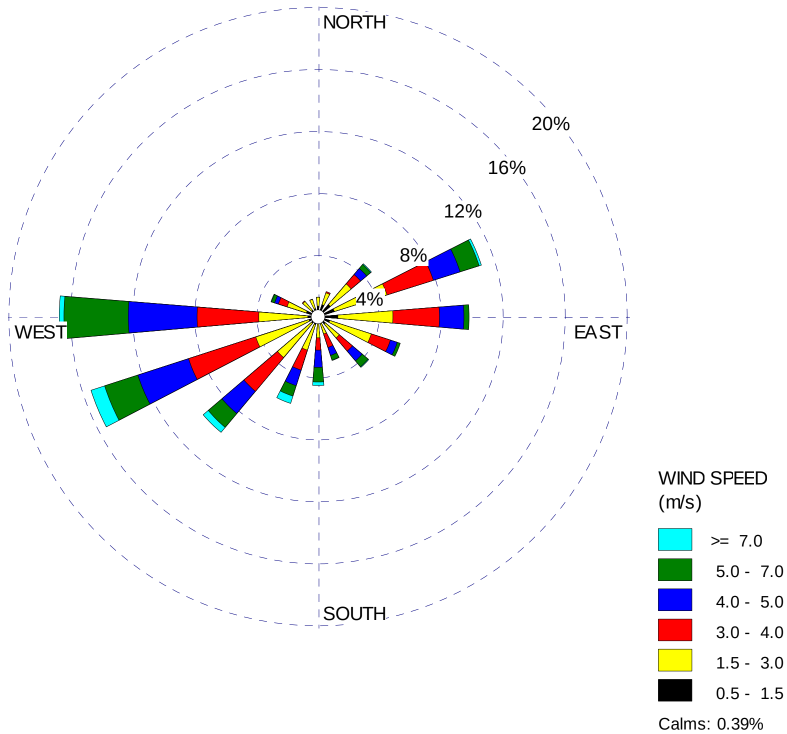


Figure 3.2-1
Windrose for Satsop, 2002 – 2003, 60 m Level

Additional meteorological parameters were obtained from Olympia and Seattle-Tacoma International Airport National Weather Service stations. The data indicate a predominant westerly wind direction (i.e., winds from the west). Calm periods were recorded for 1.5 percent of the collection period. Wind speeds averaged 3.0 meters per second (m/s), with the strongest winds 5 to 7 m/s from the east. Easterly winds were also recorded with milder wind speeds of 3 to 5 m/s.

3.2.3 IMPACTS

An Air Quality Impact Assessment was conducted for the project based on the emission rates described in Section 2.11 and 5.1 of this Application using a year of meteorological data from the project site. Computer-based dispersion modeling techniques were applied to simulate the dispersion of criteria pollutant and TAP emissions from the facility to assess compliance with NAAQS, WAAQS, ASILs, and Class I and Class II PSD increments. The dispersion modeling techniques that were employed in the analysis follow USEPA regulatory guidelines (40 CFR Part 51, Appendix W) and, more specifically, a modeling protocol approved by EFSEC and the Federal Land Managers. Please refer to Sections 5.1.3 and 5.1.4 for additional detail regarding the modeling approach and results for Class II and Class I areas, respectively.

Table 3.2-3 compares maximum model-predicted concentrations with the applicable Significant Monitoring Concentrations (SMCs) and the Significant Impact Levels (SILs) established in WAC 173-400-113(3). SMCs are thresholds that indicate whether pre-construction monitoring of background air quality is appropriate. The SILs represent incremental, project-specific impact levels that the State of Washington and USEPA accept as insignificant with respect to maintaining compliance with the NAAQS, WAAQS, and PSD increments. When predicted concentrations are less than the SILs, consideration of cumulative concentrations are not required because the project contribution is deemed insignificant.

TABLE 3.2-3
MAXIMUM PREDICTED CRITERIA POLLUTANT CONCENTRATIONS ATTRIBUTABLE TO GHE UNITS 3 AND 4
($\mu g/m^3$)

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

a. Maximum from all operating scenarios, ambient conditions, and turbine types provided by GE Energy.
b. SIL = Significant Impact Level, from WAC 173-400-113(3) except as noted.
c. SMCs and SILs for $PM_{2.5}$ have been proposed but have not been promulgated

As shown in Table 3.2-3, all predicted concentrations are less than the monitoring thresholds and established PSD SILs.

Although not required by the air permitting regulations, predicted concentrations attributable to the Units 3 and 4 may also be added to measured background concentrations for comparison with NAAQS and WAAQS. Compliance with the ambient air quality standards may be conservatively assessed by summing the highest modeled concentrations attributable to facility and maximum measured (existing) concentrations to represent other sources of emissions. This comparison is presented in Table 3.2-4. It indicates that when the maximum predicted concentrations are added to the highest monitored values, total concentrations are less than the WAAQS or NAAQS.

TABLE 3.2-4
COMPARISON OF CUMULATIVE CONCENTRATIONS TO AMBIENT AIR QUALITY STANDARDS
(µg/m³)

Pollutant	Averaging Period	Maximum Modeled Concentration[a]	Measured Background Concentration[b]	Maximum Total Concentration	NAAQS	WAAQS
NO_2	Annual	0.0889	34	34.1	100	100
CO	1-hour	365	2,100	2,465	40,000	40,000
	8-hour	18.1	1,500	1,518	10,000	10,000
SO_2	1-hour	29.9	18	47.9	-	1,050
	3-hour	9.99	16	26.0	1,300	-
	24-hour	1.38	16	17.4	365	262
	Annual	0.0311	2.6	2.63	80	52
PM_{10}	24-hour	2.71	22	24.7	150	150
	Annual	0.127	9.8	9.93	50	50
$PM_{2.5}$[c]	24-hour	0.836	17	17.8	35	-
	Annual	0.0485	6.8	6.85	15	-

a. From Table 3.2-3.
b. Maximum background concentrations from Table 3.2-2, converted from ppm to µg/m³ where necessary.
c. The modeled 24-hour average $PM_{2.5}$ concentration is the highest 8th high concentration (which is the 98th percentile over a year). The 24-hour average $PM_{2.5}$ background value is based on the 98th percentile, and the annual average background value is based on a three year average

Chapter 173-460 of the WAC requires NOC applications to include dispersion modeling of TAP emissions if anticipated emissions exceed SQERs. Model predictions are compared with TAP-specific ASILs. If calculated concentrations are less than the ASILs, a permit can be granted without further analysis. Otherwise, the applicant must revise the project or submit a health risk assessment demonstrating that toxic emissions from the project are sufficiently low to protect human health. For carcinogenic pollutants, the risk of an additional cancer case can not exceed one in 100,000. Concentrations below the ASILs indicate insignificant potential for adverse health effects from these chemicals.

The dispersion modeling analysis of TAPs emitted at rates exceeding the SQERs was conducted in the same manner as for the criteria pollutants. Depending on the chemical, either the maximum predicted 1-hour, 24-hour, or annual concentrations were compared with the ASILs. TAP emissions estimates are discussed in section 2.11 and 5.1.2 of this Application

Maximum 24-hour and annual TAP concentrations attributable to the Units 3 and 4 (and associated support units) are compared with Ecology ASILs in Table 3.2-5. Predicted maximum concentrations are less than the Ecology ASILs for all TAPs that are emitted in concentrations that exceed the SQER.

TABLE 3.2-5
MAXIMUM PREDICTED TAP CONCENTRATIONS ATTRIBUTABLE TO UNITS 3 AND 4
(µg/m³)

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

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

3.2.3.1 Ozone

40 CFR 52.21(i)(5)(i) requires any net emissions increase of 100 tpy or more of VOC or NO_x subject to PSD to perform an ambient ozone impact analysis. Because potential annual emissions of NO_x attributable to Units 3 and 4 exceed 100 tpy, an ozone impact analysis that includes all post-project emissions was conducted. A summary of that analysis is presented in Appendix A-4.

ENVIRON acquired the relevant input data and control files and replicated the MM5/SMOKE/CMAQ runs performed by Washington State University for the Puget Sound Clean Air Agency and Oregon Department of Environmental Quality in support of the various ozone studies conducted by those organizations. The scenarios in question simulate the July 26-28, 1998 ozone episode, which was meteorologically more severe than the 1996 case used in previous ozone assessments. ENVIRON examined a “base case” scenario that closely resembled those of the PSCAA and Portland SIP studies, and a “PTE scenario,” which was comprised of all base case scenario emissions plus the maximum post-project emissions from the entire Grays Harbor Energy Center.

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

The largest increase in 8-hour ozone concentration near a Class I area is about 0.01 ppb near Mount Hood Wilderness Area. This is less than 1 percent of the relevant NAAQS, indicating that the facility will not cause or significantly contribute to degradation of natural wild areas. The largest increase in 8-hour ozone concentration near the Enumclaw (Mud Mountain) observation site is less than 0.0004 ppb.

3.2.3.2 Odor

Construction of the Units 3 and 4 would include some activities that would generate odors. If oil based paints are applied to structures or equipment at the site, paint odors may be perceptible nearby. Some of the site would be paved with asphalt, and asphalt fumes may be perceptible for a short period during the paving operation. These impacts are anticipated to be slight and of short duration.

Operation of the facility would not generate odors that are perceptible off-site. The threshold of perceptibility for ammonia is approximately 0.5 ppm, or about 350 $\mu g/m^3$ (National Academy of Sciences 1979). Up to 37 pounds of ammonia could "slip" through the NO_x control equipment (i.e., SCR) and be emitted from the two HRSGs each hour. Based on the dispersion modeling results (see Table 3.2-5), this maximum emission rate would result in a ground-level hourly average concentration of approximately 1.8 $\mu g/m^3$. Therefore, ammonia attributable to Units 3 and 4 would not be perceptible off-site.

3.2.3.3 Climate, Visible Plumes, Fogging, Misting, Icing

The Units 3 and 4 design includes a 10-cell cooling tower. These cells would produce water vapor clouds that vary in size depending on meteorology and operational factors during periods of elevated relative humidity. However, such condensed plumes would usually occur during conditions of already poor or obscured visibility (i.e., fog or precipitation). A visible moisture plume from the HRSG stacks may also occur during periods with higher relatively humidity.

3.2.3.4 Dust

Because the site is flat, there would be relatively little excavation or grading prior to construction. Therefore, dust generated by excavation and grading would be short term. Dust from access roads would be controlled by applying gravel or paving the access road and watering as necessary.

After the Units 3 and 4 are completed and operational, virtually no dust would be generated on site.

3.2.4 MITIGATION

- To control dust during construction, water would be applied as necessary, access roads would be graveled or paved.
- BACT would be incorporated into the Units 3 and 4 design to reduce air pollution emissions.
- Greenhouse gas emissions would be mitigated pursuant to RCW chapter 80.70. Grays Harbor Energy LLC has chosen the "monetary path" outlined in RCW 80.70.020(5) for mitigation. At the current rate of $1.60 per metric ton of carbon dioxide, the required payment is approximately $11.75 million. Grays Harbor Energy LLC currently plans to provide EFSEC with proof of payment to a qualifying organization of the total sum, no later than one hundred twenty days after the start of commercial operation.

SECTION 3.3 WATER (WAC 463-60-322)

3.3.1 EXISTING CONDITIONS

This section summarizes existing information on surface water and groundwater resources in the vicinity of the proposed plant site and describes the proposed water supply sources for the proposed project.

3.3.1.1 Surface Water

The Grays Harbor Energy Center site is located in the lower Chehalis River Valley near Elma, Washington (Figure 3.3-1). The site is situated along the southern bank of the Chehalis River with Fuller Creek approximately 0.5 mile to the east and Workman Creek two miles to the east. Both Fuller and Workman Creeks drain to the southern side of the Chehalis River. Fuller Creek's drainage basin faces northeast and covers approximately two square miles. The Workman Creek drainage basin, which drains into the Chehalis River east of the plant site, faces northeast and covers approximately 16 square miles. The Satsop River near Satsop (USGS Station 12035000) has a drainage basin area of approximately 299 square miles. The Chehalis River, approximately 2.5 miles downstream from the site, faces south and has a drainage area of approximately 1760 square miles (USGS Station 12035002). A small drainage basin between Workman Creek and Fuller Creek is drained by Purgatory Creek.

Mean annual precipitation near Satsop is approximately 67.5 inches (Western Regional Climate Center Elma COOP Station 452531 Updated 07-29-2009). The Chehalis River system is principally fed by rainfall. Annual precipitation quantities recorded at Elma, Satsop, and Aberdeen for 1993 through 2008 are listed in Table 3.3-1. The collection of data on precipitation quantities at the Grays Harbor Energy Center site was discontinued in 2000.

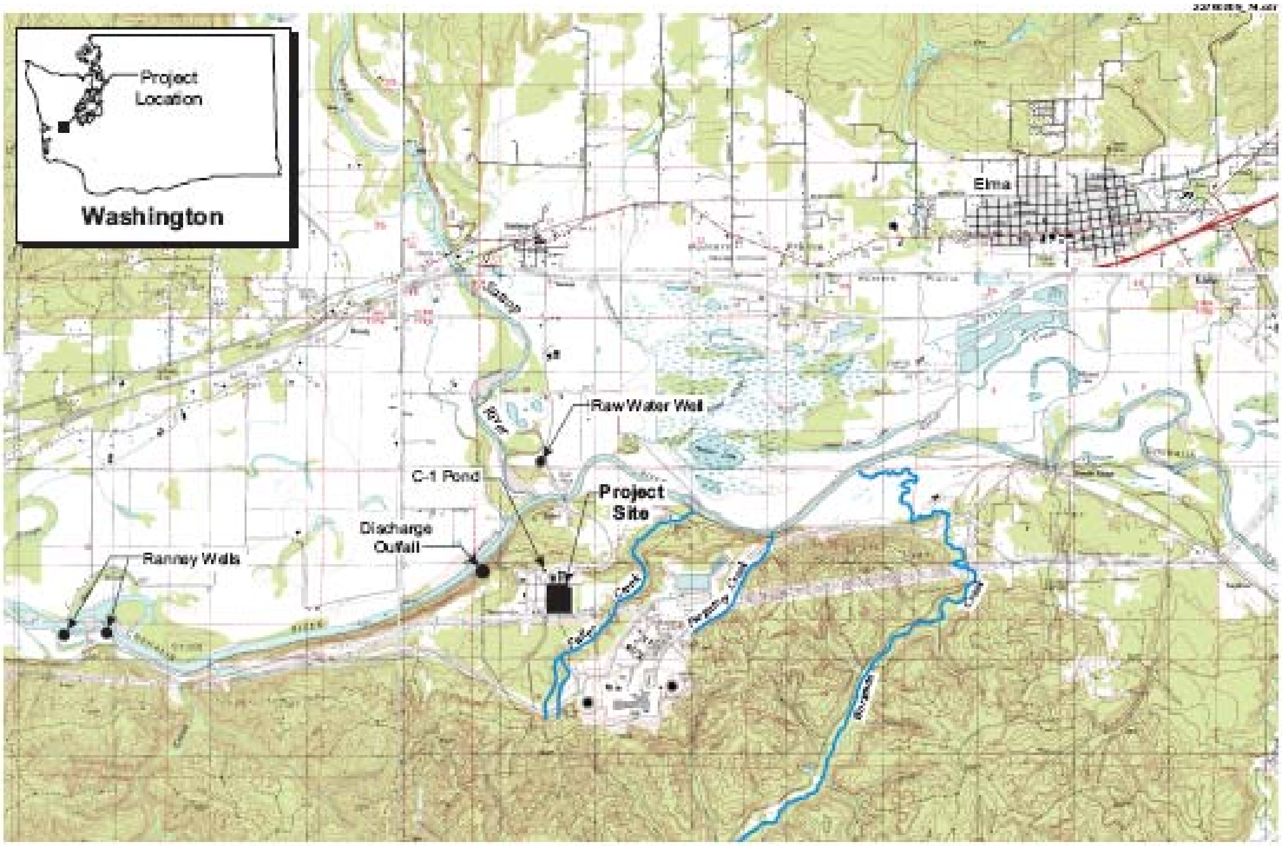


Figure 3.3-1
Area Map

Stream Flow

In accordance with WAC Chapter 173-522 and general Ecology rules, the base flows for the Grays Harbor Energy Center were established at monitoring station 12.0350.02, located at the outfall for the project. On those days not specifically identified in Table 3.3-2, Ecology plots a straight-line graph between the dates and flows shown in the table to determine base flow. The flow rate at Station 12.0350.02 is calculated as 1.5 times (Chehalis River Flow at Station 12.0275.00 + Satsop River Flow at Station 12.0350.00), per EFSEC Resolution 309.

Figure 3.3-2 shows Ecology's exceedance hydrographs for the Chehalis River at Porter. The base flows for monitoring station 12.0350.02 also are depicted. A review of the data shows that low flow conditions in the Chehalis River at Satsop typically occur from July to October, but also may occur at any time of the year. Annual peak discharge typically occurs in December through April. This annual peak discharge is a result of winter storms, which produce excess rainfalls. During periods when flows are below the base flow requirement, some withdrawals are restricted by Ecology, including withdrawal of water by the Grays Harbor Energy Center pursuant to the water authorization in the SCA. However, water rights issued prior to 1973, including those held by the Grays Harbor Public Development Authority (PDA) for the Satsop Development Park (20 cfs), and those held by the City of Aberdeen (145 cfs per Mike Randich from the City of Aberdeen Public Works Department, 8/18/09)), are not subject to flow restrictions.

TABLE 3.3-1
ANNUAL PRECIPITATION

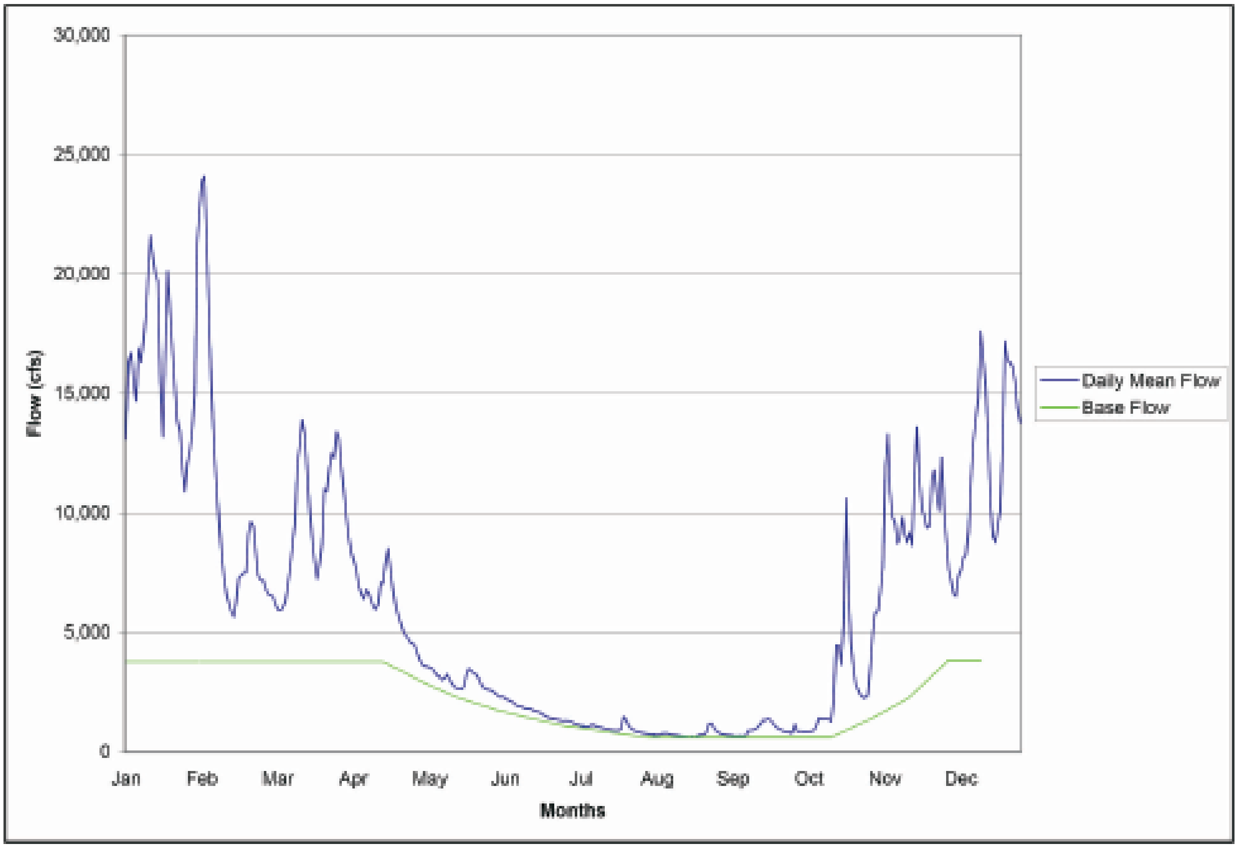
Year	Elma, Washington Station 452531 (inches)	Satsop Site (inches)	Aberdeen, Washington Station 450008 (inches)
2008	60.91		70.70
2007	71.76		81.44
2006	82.49		100.52
2005	64.25		76.57
2004	57.26		68.40
2003	77.21		92.94
2002	56.37		73.75
2001	62.56		83.54
2000	45.11	55.83	54.24
1999	86.33	95.68	111.13
1998	77.43	82.12	94.89
1997	93.24	92.63	106.73
1996	87.83	90.05	96.67
1995	75.23	79.38	98.93
1994	74.37	86.64	71.27
1993	48.12	55.11	61.34

Source: Western Regional Climate Center; last updated 07-29-2009

TABLE 3.3-2
BASE FLOW FOR MONITORING STATION 12.0350.02
ON THE CHEHALIS RIVER JUST BELOW CONFLUENCE WITH SATSOP RIVER

Month	Day	Base flow (cfs)	Month	Day	Base flow (cfs)
January	1	3800	July	1	1085
January	15	3800	July	15	860
February	1	3800	August	1	680
February	15	3800	August	15	550
March	1	3800	September	1	550
March	15	3800	September	15	550
April	1	3800	October	1	640
April	15	3800	October	15	750
May	1	2910	November	1	1305
May	15	2300	November	15	2220
June	1	1750	December	1	3800
June	15	1360	December	15	3800

Source: WAC Chapter 173-522-020; last updated June 9, 1988



Source: USGS 2008

Figure 3.3-2
Chehalis River Daily Mean Flow at Porter Station
2002 - 2007

Water Quality in the Site Vicinity

General water quality and flow data for the Chehalis River at the Porter station upstream from the site are presented in Table 3.3-3. This station is the closest station to the site to have analytical water quality testing for general chemistry parameters and study of water flow. Most of the parameters vary seasonally. Concentrations of suspended solids, turbidity, and dissolved oxygen levels are highest during high flow periods and lowest during low flow periods. Seasonal water temperature data for the Porter station are presented in Table 3.3-4. River water temperature ranged from 0.6°C on January 8, 1973 to slightly over 25.4°C on July 24, 2006. Average seasonal river water temperature ranged between 4.0°C and 22°C annually.

River water quality in the Chehalis River is considered Class A in the vicinity of the site (WAC Chapter 173-201A). Water quality of this class must meet requirements for many uses, including water supply, stock watering, fish and shellfish existence, wildlife habitat, recreation, commerce, and navigation. Water quality requirements for Class A waters include limits on fecal coliform organisms, dissolved oxygen, total dissolved gas, temperature, pH, toxic substances, and impacts to aesthetic values.

TABLE 3.3-3
CHEHALIS RIVER WATER QUALITY DATA AND FLOW RATE

	2006			2007			2008		
	Mean	Range	n[b]	Mean	Range	n[b]	Mean	Range	n[b]
Flow (cfs)	3005	320-8130	12	3931	314-19900	12	2382	425-5640	12
Specific Conductivity (µmhos/cm)	99	73-131	12	93	68-115	12	99	79-115	12
pH (pH)	7.4	6.82-7.8	12	7.47	6.77-8.04	11	7.38	7.08-7.87	11
Temperature (°C)	12.6	4.1-25.4	12	12	5-16.3	12	11.3	2.8-20.4	11
Turbidity (NTU)	6.3	0.08-15	12	5.6	1.4-22	12	12	1.1-80	12
Dissolved Oxygen (mg/l)	10.39	8.52-12.03	12	7.5	8.37-11.6	12	11.1	9.0-12.6	12
Ammonia Nitrogen (mg/l)	0.013	0.01-0.02	12	0.015	0.01-0.024	12	0.012	0.01-0.02	12
Total Phosphorus (mg/l)	0.026	0.013-0.0391	12	0.028	0.166-0.0422	12	0.037	0.018-0.117	12
Total Suspended Solids (mg/l)	13	2-34	12	10	2-31	12	10	2-34	12
Nitrites and Nitrates (mg/l)	0.643	0.558-0.899	12	0.562	0.355-0.746	12	0.512	0.330-0.695	12
Fecal Coliform (colonies/100 ml)	15	4-46	12	15	6-29	12	24.3	4-160	12

Data are for Chehalis River at Porter Station WRIA 23A070 from www.ecy.wa.gov/apps/watersheds/riv

b. n = Total number of data values

TABLE 3.3-4
CHEHALIS RIVER TEMPERATURE DATA FROM PORTER STATION

Date	Temperature (°C)	Date	Temperature (°C)
1/24/2000	5.7	3/29/2005	8.2
2/21/2000	4.3	4/19/2005	9.2
3/27/2000	6.9	5/24/2005	12.1
4/24/2000	9.7	6/14/2005	15.7
5/22/2000	12.3	7/19/2005	20.5
6/26/2000	15.5	8/16/2005	21.1
7/24/2000	16.4	9/19/2005	16
8/28/2000	17.2	10/19/2005	14
9/25/2000	13.2	11/14/2005	8.6
10/23/2000	9.3	12/12/2005	4.1
11/27/2000	4.4	1/25/2006	7.2
12/11/2000	2.9	2/13/2006	7
1/29/2001	4.6	3/13/2006	6
2/19/2001	5.1	4/17/2006	8.6
3/26/2001	9.3	5/15/2006	16.2
4/23/2001	10.6	6/19/2006	17.3
5/28/2001	16.2	7/24/2006	25.4
6/25/2001	15.5	8/21/2006	20.1
7/23/2001	17.7	9/25/2006	16.3
8/27/2001	17.7	10/18/2006	12.3
9/24/2001	17.3	11/15/2006	8.3
10/29/2001	8.6	12/20/2006	5
11/26/2001	7.4	1/24/2007	5.9
12/10/2001	6.2	2/14/2007	7.4
1/28/2002	4.4	3/21/2007	8.6
2/18/2002	6.8	4/25/2007	11.8
3/25/2002	9.6	5/23/2007	14.5
4/15/2002	8.9	6/13/2007	16.3

Date	Temperature (°C)	Date	Temperature (°C)
5/27/2002	15.4	7/18/2007	20
6/24/2002	18.6	8/21/2007	19
7/29/2002	18.7	9/25/2007	15.4
8/26/2002	19.7	10/30/2007	
9/23/2002	15.1	11/27/2007	4.6
10/28/2002	10.2	12/17/2007	6
11/18/2002	8.5	1/28/2008	2.8
12/9/2002	5.4	2/27/2008	7.7
1/27/2003	9.8	3/18/2008	7.4
2/24/2003	6	4/22/2008	7.9
3/17/2003	8.7	5/20/2008	17.4
4/21/2003	10.7	6/17/2008	15.3
5/19/2003	12.2	7/22/2008	19.2
6/16/2003	17.9	8/19/2008	20.4
7/21/2003	22.5	9/23/2008	15.7
8/18/2003	20.6		
9/22/2003	15.9		
10/20/2003	13.3		
11/17/2003	7.6		
12/15/2003	6.4		
1/26/2004	5.8		
2/23/2004	7.5		
3/23/2004	10.3		
4/20/2004	10.9		
5/18/2004	16.1		
6/22/2004	20.5		
7/20/2004	21.4		
8/16/2004	23.7		
9/21/2004	12.8		
10/19/2004	12		
11/16/2004	9.4		
12/14/2004	7.6		
1/25/2005	8.9		
2/15/2005	5.1		

Source: USGS (1970 - 2007) and www.ecy.wa.gov , Chehalis River @Porter Station 23A070

3.3.1.2 Groundwater

Groundwater Occurrence

Significant groundwater aquifers in the plant site vicinity occur in the alluvial valleys of the Chehalis River, Satsop River, and tributary rivers, as well as in smaller perched aquifers in the marginal terrace deposits. Little useable water occurs in the underlying Tertiary bedrock (WPPSS 1982). The alluvial deposits are approximately 100 feet thick north of the site vicinity, and extend to depths of as much as 200 feet in the lower Chehalis River valley. The alluvial aquifer under the Grays Harbor Energy Center site consists of alluvial sediments including sand, gravel, and silt and is confined by a thin layer of silt flood deposits, approximately 11 feet thick.

Groundwater flow in the alluvial aquifer is likely to generally parallel the flow of the Chehalis River, toward the west. During periods of low river flow, the flow direction in the aquifer would likely be skewed toward the river, where it would discharge. During high river flow periods, flow direction would be skewed toward the valley walls due to aquifer recharge from the river. According to aquifer tests performed prior to installation of the Ranney collector system, the gradient of the potentiometric surface is estimated to be approximately 15 feet per mile in a down-valley direction (WPPSS 1974). The alluvial aquifer extends north approximately two miles across the Chehalis River Valley, about 14 miles downstream to Grays Harbor, and about 15 miles upstream to the eastern limit of Grays Harbor County. The northern, southern, and basal boundaries of the alluvial aquifer are formed by a Tertiary sandstone formation that occurs at the southern portion of the site, and contains little groundwater.

Groundwater depths in the alluvium may range from near-surface in slough and wetland areas to greater than 20 feet bgs. Reported groundwater withdrawal rates from wells in the eastern Grays Harbor County area range from 5 gpm for domestic supplies to over 900 gpm for irrigation purposes (Ecology 2001). Wells screened at depths of less than 100 feet typically yield lower quantities whereas those screened below 100 feet potentially yield up to 3,000 gpm. The interconnection between shallow and deep groundwater in the alluvial aquifer and surface water sources such as the Chehalis River is known to be high. Groundwater wells screened in the alluvium typically draw upon both groundwater and surface water sources. Recharge to the alluvial aquifer is from direct precipitation as well as from surface water sources (e.g., Chehalis River).

As a part of investigations related to the nuclear projects, a pumping test of the aquifer was performed in anticipation of installing the Ranney wells in alluvial deposits at the confluence of the Satsop and Chehalis Rivers (the current raw water well location). Test results indicated that average transmissivity of the aquifer is 1,242,000 gallons per day (gpd) per foot and the aquifer is hydraulically connected with the Satsop River (WPPSS 1974). Pumping tests after the installation of the Ranney wells in 1980 yielded an aquifer transmissivity of approximately 560,000 gpd per foot. Natural groundwater flow conditions are governed by the transmissivity and gradient of the aquifer. Based on the pumping test data from the Ranney collector system, the calculated natural underflow in the alluvial aquifer is approximately 8 to 18 million gallons per day per mile of aquifer width. More accurate calculation of this value is difficult due to the Ranney wells' interaction with both the aquifer and surface water systems and limitations in separating the ground and surface water components of the flow.

Smaller, discontinuous perched aquifers, which occur in the unconsolidated terrace deposits on the Grays Harbor Energy Center and surrounding Satsop Development Park properties, lie above the alluvial valley (WPPSS 1982). The groundwater level in the terrace deposits beneath the property varies from 15 to 50 feet bgs. The flow of water through the perched aquifers is locally controlled by topography. Flow will likely tend toward the Chehalis river valley, where it will join the regional groundwater system. Recharge to the terrace deposits is by direct infiltration.

Limited groundwater quality analyses for samples taken at the Ranney collector system have been previously provided to EFSEC (see Application 94-1, Appendix D, Ranney Well Information). Groundwater and surface water quality are compared in Section 3.3.1.3.

Groundwater Wells in the Site Vicinity

There are no groundwater wells on the Grays Harbor Energy Center site. Groundwater wells on Satsop Development Park property include a groundwater collection system referred to as the Ranney collector system (makeup water well), the raw (potable and construction) water well, and a small domestic well. Other domestic wells occur in the area (within several miles of the site), and are generally located west of the site or on the north side of the river. Three domestic wells are known to be screened in the terrace deposits.

The Ranney wells consist of two vertically placed caissons that penetrate beneath the Chehalis River bed within the alluvial gravel beneath the river. The caissons are connected to a tier of horizontal collector laterals that extend in a radial pattern from the caisson. Each caisson potentially yields 26 million gallons per day (mgd), or 40 cfs (WPPSS 1984). Pump tests completed in 1982 in the collector system indicated that the wells draw surface water from the Chehalis River as well as groundwater in the alluvium. It was determined that the Ranney wells derive up to 88 percent of their supply from the Chehalis River via infiltration, with the remaining 12 percent drawn from the surrounding alluvial aquifer (WPPSS 1982). Drawdown effects resulting from pumping 20,833 gpm were estimated to lower water levels in surrounding farm and irrigation wells 1 to 2.5 feet. Maximum withdrawals for the Grays Harbor Energy Center with all four units operating will be 16.0 cfs or 7180 gpm and will be substantially less than those projected for the nuclear plants, and therefore the impact to surrounding farm and irrigation wells is expected to be negligible.

3.3.1.3 Comparison of Surface and Groundwater Quality

As described above, it was determined that the Ranney wells derive up to 88 percent of their supply from the Chehalis River via infiltration, with the remaining 12 percent drawn from the surrounding alluvial aquifer (WPPSS 1982). It is unknown as to whether these percentages will remain the same with lower flows anticipated for the Grays Harbor Energy Center and the Satsop Development Park (non-low flow maximum of 36 cfs based on 20 cfs for the Grays Harbor PDA, and 16 cfs for the Grays Harbor Energy Center, and a maximum of 26.5 cfs during low flow conditions).

The Chehalis River water quality from five different locations upstream and downstream of the Ranney wells was detailed in the Receiving Water Study (Energy Northwest 2004). A summary of the results is shown in Table 3.3-5, Chehalis River Water Quality Data.

For a comparison between surface water quality and groundwater quality, water quality data from the Chehalis River collected during the receiving water study of 2004 (Table 3.3-5) may be compared to the data collected from the Ranney Wells on August 5, 2009, which are summarized in Table 3.3-6.

TABLE 3.3-5
CHEHALIS RIVER WATER QUALITY DATA

Samples Taken at Five Stations[a]	Stations 1 & 2 (Upstream)	Station 3 (Discharge Area)	Stations 4 & 5 (Downstream)
Ammonia (mg/l)	0.026-0.028	0.026	0.024-0.025
Total Cadmium (µg/l)	0.025-0.031	0.182	0.025-0.032
Total Chromium (µg/l)	1.154-1.172	1.042	0.955-0.998
Total Copper (µg/l)	2.079-2.342	1.863	1.645-1.695
Dissolved Oxygen (mg/l)	8.59-8.66	8.57	8.48-8.54
Hardness (mg/l)	31	30	32-33
Total Lead (µg/l)	0.163-0.177	0.110	0.105-0.166
Total Mercury (µg/L)	0.0015 – 0.0025	0.0017	0.0015
pH (pH)	7.34	7.43	7.52-7.62
Total Selenium (µg/L)	0.1410-0.2425	0.1450	0.1610-0.1615
Temperature (°C)	12.69-12.43	12.44	12.82-13.00
Total Suspended Solids (mg/L)	18.7-30.4	15.1	9.8-11.0
Total Zinc (µg/L)	1.986-2.283	2.413	1.329-1.363

Source: Energy Northwest (2004)

a. Station results are averages taken over a 6-month period. Samples taken at two upstream stations, two downstream stations, and the Discharge Area

TABLE 3.3-6
RANNEY WELL WATER QUALITY DATA

Parameter[a]	Ranney Well Water Quality Data[a]
Ammonia (mg/l)	NAv
Total Cadmium (µg/l)	ND
Total Chromium (µg/l)	0.00026
Total Copper (µg/l)	0.00039
Dissolved Oxygen (mg/l)	NAv
Hardness (mg/l)	NAv
Total Lead (µg/l)	0.00044
Total Mercury (µg/L)	ND
pH (pH)	7.68
Total Selenium (µg/L)	0.00027
Temperature (°C)	NAv
Total Suspended Solids (mg/L)	NAv
Total Zinc (µg/L)	ND

a. Dragon Analytical Laboratory Results from two samples collected on August 5, 2009.

3.3.1.4 Existing Water Appropriations

Existing surface water right appropriations in the Chehalis Basin include water for domestic, municipal, irrigation/agricultural, power, commercial, and fish propagation purposes. Critical periods for potential impacts of water withdrawals to the environment and to existing surface water rights occur during low flow periods, typically from July through October.

A water right provides legal authorization to use a certain amount of surface water or groundwater for specific beneficial purposes. Diversion of surface or groundwater requires a water right except for minimal diversions. The proposed water use must satisfy statutory requirements in order for Ecology to issue a water right permit. Statutes require: beneficial use of the water; the use must not cause impairment of existing rights; water is available for appropriation; and issuance of the water right must not be deemed detrimental to the public interest.

A review of current surface and groundwater appropriations filed with Ecology indicates that industry is the largest appropriator in the basin (42 percent of the total consumptive use appropriations) followed by municipal (44 percent), irrigation (1.2 percent), and domestic use (1.1 percent). Municipal supply uses both surface and groundwater resources. In-stream flows are necessary to maintain anadromous fish populations, which attract sport and commercial fishing interests. In-stream flow appropriations also are pursued for subsistence fishing and aesthetic concerns.

Ecology has established a water resources program for the Chehalis River basin in order to establish base flow, provide protection for future allocations, establish a priority scheme for future rights during water shortage periods, and identify streams closed to further consumptive appropriations (WAC 173-522). The only downstream river that has been closed to consumptive appropriations is the Wynoochee River which has had seasonal closures since March 9, 1962 between May 1 and October 31 (WAC 173-522-050). Base flow requirements for the Chehalis River below the confluence with the Satsop River (Station 12.0350.02) have been developed by Ecology for maintenance of in-stream flows (Table 3.3-2).

The Chehalis River basin is divided into two Water Resources Inventory Areas (WRIAs): an upper basin (WRIA-23) and lower basin (WRIA-22). The site is located in the lower basin. Specific water resource management goals are assigned to each WRIA, including base flow regulations. Base flows are in-stream flow limits which allow “preservation of wildlife, fish, scenic, aesthetic, and other environmental values, and navigational values” (Ecology 1975). While existing water right permits are not affected by base flow restrictions, future water right permits and certificates will not allow appropriation of surface water from the Chehalis River and its tributaries below the base flow levels specified by regulation. In addition, future groundwater appropriations will be affected by base flow provisions if the groundwater in question is determined to be in hydraulic continuity with the affected stream section.

Several surface water and groundwater users have been identified in the area of the Ranney wells. The intended use is for domestic, stockwater, and irrigation purposes. Ecology’s listing of water right permits for the Ranney well area includes withdrawal quantities ranging from 300 to 800 gpm.

3.3.2 IMPACTS

This section addresses potential impacts to surface water and groundwater due to construction and operation of the Units 3 and 4. Surface water runoff controls during operation are presented below and in the approved Erosion Control Plan.

3.3.2.1 Surface Water

Runoff from the site will be routed to the C-1 erosion control pond, located on Satsop Development Park property west of the site. The C-1 pond is designed and maintained to store runoff from the 100-year rainfall event. As a result of implementation of this plan, surface water impacts due to construction of the plant will be temporary and minor.

3.3.2.2 Groundwater

The Grays Harbor Energy Center site is situated on terrace deposits with smaller, discontinuous perched aquifers that may contribute little recharge to adjacent surface water bodies. In addition, the gravel fill currently on the site is underlain by a liner that restricts water infiltration. As a result, construction of Units 3 and 4 will not have a significant impact on groundwater resources.

3.3.2.3 Impacts of Process Water Withdrawal

Process water will continue to be supplied from the existing Ranney wells and transported through the existing make-up water line to the Grays Harbor Energy Center (Figure 2.3-4, Process Water Conceptual Flow Diagram). The make-up water line was originally designed and constructed for the nuclear plants, and is capable of carrying 80 cfs of water. The existing Grays Harbor Energy Center is authorized to use 9.2 cfs from the Ranney wells (per EFSEC Resolution 309), and the Grays Harbor PDA has a permitted water right to withdraw an additional 20 cfs from the Ranney wells. The Certificate Holder is proposing to obtain up to an additional 6.5 cfs of water from an existing water rights' holder, such as the Grays Harbor PDA or the City of Aberdeen, and is in the process of negotiating an agreement to obtain water. If water is leased from an existing right held by other than the PDA, the holder of that right would apply to Ecology to transfer the point of intake to the Ranney wells. This could potentially increase the water withdrawal to a maximum of 36 cfs (20 cfs for the PDA and 16 cfs total for Grays Harbor Energy), which is still less than half of the amount the existing wells and water line were designed to carry. Therefore, the capacity of the Ranney wells and make-up water line are more than sufficient for the permitted uses.

The Ranney wells are located on the southern bank of the Chehalis River, approximately four miles downriver of the plant site near the river's confluence with Elizabeth Creek. The wells penetrate to a depth of approximately 120 feet into the alluvial aquifer associated with the Chehalis River. The estimated radius of groundwater influence for the Ranney wells is 2,000 feet after 30 days of pumping. Ecology well records do not show groundwater wells within 2,000 feet of either Ranney well. However, if a groundwater well in the alluvial deposits was within 2,000 feet of the Ranney wells, it would experience some drawdown in water level due to the pumping at the Ranney wells. Because Units 3 and 4 are intended to operate using an existing permitted water right, the Grays Harbor Energy Center will not draw additional groundwater from the alluvial aquifer system beyond that already anticipated by existing water rights and authorizations. The additional 6.5 cfs that will be withdrawn for the Grays Harbor Energy Center should not change the temperature or the water quality of the Chehalis River since the amount withdrawn is about 1 to 2% of the flow in the river.

3.3.2.4 Potable Water Supply Withdrawal

Potable water is provided to the Grays Harbor Energy Center by the Grays Harbor PDA under an existing agreement. The agreement covers the existing facility and would also apply to Units 3 and 4.

3.3.2.5 Process Water Discharge Summary

The Grays Harbor Energy Center has been designed to minimize wastewater discharges. Like the existing facility, the design for Units 3 and 4 includes waste streams that will be treated as necessary and co-mingled prior to discharge. These waste streams consist of cooling tower blowdown, oil/water-separator decant, and metal cleaning waste. The co-mingled waste streams will be discharged to the Satsop Development Park's blowdown line in accordance with the NPDES permit for the Grays Harbor Energy Center (Permit No. WA-002496-1; see Section 2.8.2). As shown on Figure 2.3-4, the outfall discharges to the Chehalis River. Discharge of total process water (from all Units 1-4) to the river will be at a maximum rate of approximately 2.84 cfs (1,320 gpm) when operating with duct firing.

The temperature of the cooling tower blowdown at the point of discharge from the Grays Harbor Energy Center to the blowdown line will be below the limit of 16^{o}C, the temperature limitation in the existing NPDES Permit, as required by the SCA.

Based on preliminary water balances for the project with all four turbines operating, evaporative losses and other flow reduction losses from the combustion turbine process range from 2,104 to 3,230 gpm for Units 3 and 4.

3.3.2.6 Sanitary Water Discharge

Sanitary water effluent will be released to an existing on-site septic system. The system has been designed to Grays Harbor County standards to accommodate up to 3,500 gpd sanitary waste. Conservatively estimating the number of people on site (staff and visitors) per day, and using a sanitary waste flow typical for an operating plant, the flow to the on-site system would be less than 3,500 gpd.

3.3.3 MITIGATION MEASURES

3.3.3.1 Surface Water

To minimize impacts on surface water, contractors will use BMPs for erosion and sediment control during construction of Units 3 and 4 and will implement a plan that complies with the requirements of the existing Erosion and Sedimentation Control Plan. BMPs will include limiting certain construction activities and installing temporary control structures such as sediment traps, silt fences, and diversion ditches.

To meet the temperature requirements of the discharge, heat exchangers will be used to control the temperature of the cooling water discharge.

3.3.3.2 Groundwater

Process water is discharged via a diffuser to the Chehalis River, and stormwater is directed to the C-1 pond for treatment and discharged via surface drainage to the Chehalis River. The septic drain field is the only water that could reach groundwater. The design of the existing on-site septic system included a professional engineer's report on site conditions, schedule for development, water balance analysis, overall effects of the proposed system on the surrounding area, and any local zoning requirements. The placement and design of the system allows infiltration of effluent but inhibits its direct release to surface and/or groundwater bodies.

Additionally, the project is situated on terrace deposits with smaller, discontinuous perched aquifers and the site is built on gravel fill, which is underlain by a liner that restricts water infiltration. As a result, plant construction will not have an impact on groundwater quality. Therefore, no significant impacts to groundwater quantity or quality are likely to occur.

SECTION 3.4 PLANTS AND ANIMALS (WAC 463-60-332)

EFSEC has previously evaluated the plants and animals associated with the 22-acre project site, and authorized construction of the Gray Harbor Energy Center on the site. Units 3 and 4 will be constructed on the same site. An additional 10 acres of adjacent property will be used for construction laydown and site access.

This section summarizes information provided in the previous application addressing the vegetation, fish, and wildlife studies concerning the original project site, and provides additional information regarding the 10-acre construction laydown and access area.

Vegetation studies were conducted by Dames & Moore biologists during May and June 1994. These surveys of the study area consisted of reviewing and assessing aerial photographs, National Wetland Inventory Maps, and county soil surveys. Surveys completed in 1994 were for the 22-acre Grays Harbor Energy Center, as well as the pipeline corridor, and the transmission line corridor. The 10-acre construction laydown and access area to the east was surveyed in 1994 as part of the pipeline corridor and the conditions field verified on June 19, 2008 by a URS biologist.

3.4.1 HABITAT AND VEGETATION

3.4.1.1 Existing Conditions

The 22-acre site was previously used as a construction laydown area for the Satsop nuclear facilities. The site has been graded several times, most recently as part of the Grays Harbor Energy Center construction. The site is scarcely vegetated and covered in gravel.

The area immediately surrounding the site is a mix of developed and undeveloped areas. The area north of the site is industrial with some conifers to the northeast. The area south of the site consists of the transmission line corridor and is mostly shrubs, followed by conifers further south. To the west of the site is Keys Road. The proposed 10-acre construction laydown and access area is adjacent to and east of the existing site and consists of approximately 5 acres of thinned conifers managed as a mature forest, and 5 acres of grassland/agriculture. The grasslands continue to the east and are mowed every year.

The original nuclear power plant site comprised 1,600 acres, of which 400 acres were developed and 1,200 acres were left undeveloped. Developed areas include land that is essentially cleared of all vegetation, such as roads, industrial parks, and other buildings and facilities. Planted grasses, forbs, shrubs, and trees typically dominate these areas. These areas also have a higher proportion of ornamentals.

The surrounding area consists of developed land, coniferous forest, regenerated coniferous forest, grassland/agriculture, and shrubland.

Developed Areas. Although there are varying levels of development, these areas generally provide low-quality habitat because of the lack of native vegetation and the level of human disturbance. Species observed in developed areas during field reconnaissance in 1994 included European starlings, rock doves, American crows, house sparrows, and opossums, all of which are highly adapted to human-modified environments.

Coniferous Forest. Forest habitat consists of areas dominated by coniferous and/or deciduous tree cover, and associated forest understory vegetation. Coniferous forest is the predominant habitat in the areas around the study area to the northeast, south past the transmission lines, and in five acres of the construction laydown and access area. Deciduous and mixed forest occurs in smaller patches, generally interspersed with coniferous forest stands.

The quality of forest habitat for wildlife varies depending on the age or successional stage of the stand, the presence of several vegetative layers (i.e., shrub/midstory and herbaceous/understory vegetation), the presence of snags and downed logs, and the size of the stand.

Wildlife occurring in forest habitat in the study area is typical of wildlife occurring in second-growth forest stands throughout western Washington. Common forest songbirds observed in the 1994 surveys throughout the study area included Pacific slope flycatchers, Steller's jays, chestnut-backed chickadees, red-breasted nuthatches, brown creepers, winter wrens, golden-crowned kinglets, varied thrushes, solitary vireos, Townsend's warblers, Wilson's warblers, western tanagers, and black-headed grosbeaks. Sign of black-tailed deer, mountain beaver, and Douglas' squirrel also was observed in many forested areas.

Regenerating Coniferous Forest. Regenerating coniferous forest is defined as areas that were clearcut up to 20 years ago and where successional advancement is moving rapidly toward forest development. For the first few years after clearcutting, these stands are dominated by a mix of forbs, ferns, and shrubs, such as salal, Oregon grape, trailing blackberry, vine maple, sword fern, bracken fern, and red alder. The diversity of plant species is higher in regenerating stands than during later stages of forest succession because the open space following clearcutting allows many plant species to invade. Within 5 to 10 years after clearcutting, the conifer seedlings (primarily Douglas fir) become the dominant vegetation. Herbs, ferns, and shrubs become overtopped by young trees and often die under the taller growing species. By age 20, the stands have developed closed canopies and are classified as forest habitat. Regenerating forest is interspersed with forest habitat in the study area.

Many wildlife species are found in regenerating forest stands since the variety of plants and seeds provide an abundance and diversity of food. The young plants are fairly palatable, are accessible to ground-foraging animals (i.e., deer), and provide hiding cover for songbirds and other wildlife. Wildlife commonly observed in regenerating coniferous forest during the 1994 field surveys included ruffed grouse, mourning doves, rufous hummingbirds, Swainson's thrushes, orange-crowned warblers, MacGillivray's warblers, Wilson's warblers, rufous-sided towhees, song sparrows, white-crowned sparrows, dark-eyed juncos, and American goldfinches. Red-tailed hawks occasionally were observed circling over the open stands. Sign of coyote, black-tailed deer, and elk was observed within regenerating forest habitat and on logging roads through the regenerating stands. Garter snakes were common along the edges of logging roads. Mountain beaver sign also was prevalent throughout many of the stands.

Grassland/Agricultural Areas. Grasslands and agricultural areas include pastures, croplands, orchards, hayfields, and untended fields. Open areas also provide foraging habitat for raptors. Red-tailed hawks and northern harriers occur year-round in open agricultural areas. American kestrels occur in open areas in the study area during winter. Songbirds occurring in this habitat type include violet-green swallows, savannah sparrows, and American robins.

Shrubland. Shrub habitat is the primary habitat type in existing rights-of-way for the BPA transmission line south of the project site. Shrub habitat is not a forest successional stage. Shrub habitat is dominated primarily by Scotch broom, but also includes trailing blackberry, Himalayan blackberry, salmonberry, thimbleberry, and young red alder.

Regional Conditions. The study area is located within the Puget Trough Province (Franklin and Dyrness 1988). Relief is moderate, with elevations seldom exceeding 525 feet. The majority of the soils were formed in glacial materials under the influence of coniferous forest vegetation.

The study area also is within the Western hemlock (*Tsuga heterophylla*) Zone (Franklin and Dyrness 1988). This zone is the most extensive zone in western Washington and is named for the potential climax species (Western hemlock). This zone has a wet, mild, maritime climate, although climatic variation is widespread. The greatest amount of precipitation occurs in the winter, with only six to nine percent of the total precipitation during the summer. The climatic variation and precipitation patterns create moisture stresses that result in distinct community patterns along moisture gradients.

Plant Site. Prior to the construction of the Grays Harbor Energy Center, most of the 22-acre site had been filled and graded with several feet of compacted gravel (Parametrix 1993), lacked vegetation, and a portion of the site was covered with asphalt. The site was used as a construction laydown area and had stockpiles of concrete forms, steel reinforcing bars, and other materials remaining from construction of the nuclear facilities located on the Satsop Power Plant property. The entire site was re-graded for the construction of the Grays Harbor Energy Center, including the portion of the site that would be used for the construction of Units 3 and 4.

Construction Laydown and Access Area. The 10-acre construction laydown area consists of approximately 5 acres of thinned conifers managed as a coniferous forest and 5 acres of grassland/agriculture that is mowed every year. Table 3.4-1 lists vegetation observed in the construction laydown area during the June 2008 site visit.

TABLE 3.4-1
PLANT SPECIES OBSERVED ON CONSTRUCTION LAYDOWN AREA

Scientific Name	Common Name	Native or Introduced
Trees		
Acer circinatum	vine maple	N
Alnus rubra	red alder	N
Fraxinus latifolia	Oregon ash	N
Malus sp.	apple	I
Rhamnus purshiana	cascara	N
Populus balsamifera	black cottonwood	N
Pseudotsuga menziesii	Douglas-fir	N
Tsuga heterophylla	Western hemlock	N
Shrubs		
Berberis aquifolium	tall Oregongrape	N
Cytisus scoparius	Scot's broom	I
Gaultheria shallon	salal	N
Hedera helix	English ivy	I
Ilex aquifolium	English holly	I
Oemleria cerasiformis	osoberry	N
Oplopanax horridus	devil’s club	N
Ribes sanguineum	red-flowering currant	N
Rosa nutkana	Nootka rose	N
Rubus armeniacus	Himalayan blackberry	I
Rubus spectabilis	salmonberry	N
Rubus ursinus	trailing blackberry	N
Sambucus racemosa	red elderberry	N
Symphoricarpos albus	snowberry	N
Vaccinium parvifolium	red huckleberry	N
Herbs		
Achlys triphylla	Vanilla-leaf	N
Bellis perennis	English daisy	I
Cerastium sp.	chickweed	I
Circaea alpina	Enchanter’s nightshade	N
Cirsium vulgare	bull thistle	I
Claytonia sibirica	Siberian miner’s-lettuce	N
Daucus carota	Queen Anne's lace	I
Dicentra Formosa	Pacific bleeding heart	N
Digitalis pupurea	foxglove	I
Epilobium angustifolium	fireweed	N
Galium aparine	cleavers	N
Lotus corniculatus	birds-foot trefoil	I
Maianthemum dilatatum	false lily-of-the-valley	N
Plantago lanceolata	English plantain	I
Ranunculus repens	creeping buttercup	I
Rhinanthus minor	yellow rattle	N

Scientific Name	Common Name	Native or Introduced
Rumex acetosella	sheep sorrel	I
Rumex obtusifolius	bitter dock	I
Smilacina racemosa	False solomons seal	N
Solidago canadensis	Canada goldenrod	N
Solanum dulcamara	bittersweet nightshade	I
Stachys sp.	hedgenettle	I
Taraxacum officinale	common dandelion	I
Trifolium repens	white clover	I
Trifolium dubium	Small hop-clover	I
Trillium ovatum	Western trillium	N
Vicia sp.	vetch	N
Grasses, Sedges, Rushes		
Agrostis capillaris	colonial bentgrass	I
Anthoxanthum odoratum	sweet vernalgrass	I
Dactylis glomerata	orchardgrass	I
Elytrigia repens	quackgrass	I
Festuca arundinacea	tall fescue	I
Holcus lanatus	velvetgrass	I
Juncus effusus	soft rush	N
Lolium perenne	perennial ryegrass	I
Phalaris arundinacea	reed canarygrass	I
Poa annua		I
Poa sp.	bluegrass	I
Ferns and Allies		
Blechnum spicant	deer fern	N
Polystichum munitum	sword fern	N
Pteridium aquilinum	bracken fern	N

3.4.1.2 Impacts

Plant Site

Since the area of the existing site proposed for Units 3 and 4 is not vegetated, there will not be any impacts to upland vegetation due to construction or operation of the additional two units. The forested and pasture areas surrounding the site will not be impacted by construction.

Construction Laydown and Access Area

There would be a permanent impact to the forest and mown pasture habitat on the construction laydown and access area due to the removal of the trees and pasture.

3.4.2 FISH

Like the existing Grays Harbor Energy Center facility, Units 3 and 4 would use water from the existing Ranney wells for cooling, and discharge water to the Chehalis River through the existing outfall. Previous applications have addressed the fish and aquatic resources in the area, and addressed the potential impacts associated with the existing facility. The aquatic area studied previously included the Chehalis River within 2,000 feet of the Ranney wells located at approximately river mile (RM) 17 and in the vicinity of the discharge outfall at approximately RM 19.6.

Currently, a maximum of 29.2 cfs is authorized to be withdrawn from the Ranney wells based on 20 cfs for the Grays Harbor PDA and an additional 9.2 cfs for the Grays Harbor Energy Center. Operation of Units 3 and 4 would use up to an additional 6.5 cfs of water from the Ranney wells. This water could come from the Grays Harbor PDA's 20 cfs authorization, or alternatively be obtained from another water rights holder such as the City of Aberdeen. If obtained from an entity other than the PDA, the potential withdrawal could be a maximum of 36 cfs when the river is above base flow, or 26.5 cfs during low flow conditions. The operations of Units 3 and 4 would increase the discharge of water at the diffuser outfall by as much as 3 cfs. The temperature of the discharge water will be below the existing NPDES permit limit of 16ºC. The results of mixing zone modeling indicate that all modeled constituents of the discharge water would be diluted to below water quality standards and permit limits within the regulated mixing zone. Approximately 88 percent of the water in the well comes from the Chehalis River, for a total reduction in river flow below the outfall of 5.7 cfs (88 percent of 6.5 cfs). This section describes the fisheries and aquatic resources important to the Grays Harbor Energy Center study area, which includes portions of the Chehalis River Basin.

Data sources reviewed in the preparation of this section include the US Fish and Wildlife Service (USFWS 2008), National Marine Fisheries Service (NMFS 2008), Washington Department of Fish and Wildlife (WDFW 2008a, 2008b, 2008c), Washington Department of Fisheries (WDF 1975), and Washington Department of Wildlife (WDW 1992). Maps from the then-named Washington Department of Fisheries stream catalog were used to obtain information about the locations of cascades and falls (WDF 1975). Maps from various sources were used to delineate stream use by fish (WDF 1975; WDW 1992; WDFW 2000, 2002, 2004, 2008b and 2008c; and Smith and Wenger 2001). Additional data was reviewed to determine fish species presence in the Chehalis River (Baker 2008, Henning 2004, Jeanes et al. 2003, Kelley 1997, McPhail 1969, USFWS 2004, WDF 1971, Wydoski and Whitney 2003, and Mongillo and Hallock 1995, 1997, and 1999).

3.4.2.1 Existing Conditions

Chehalis River

Outside of the Columbia River system, the Chehalis River is the largest watershed in the state of Washington (Seiler 1989). The Chehalis River is classified as Class A (excellent), as are most of the water bodies of the Chehalis Basin. Beneficial uses of Class AA and Class A waters include water supply, fish spawning and rearing, recreation, and navigation (LCCD 1992a and 1992b). The Chehalis River flows into Grays Harbor, the fourth largest estuary in the western United States.

The Chehalis River in the aquatic study area has a low gradient with deciduous vegetation along its banks. The Chehalis River in the aquatic study area provides a fairly uniform habitat for fish. The river channel ranges from 60 to 80 yards in width with a number of slow-moving pools followed by relatively short riffle sections. The bottom is composed primarily of gravel and rubble (WDF 1975).

Limiting factors affecting fisheries resources may include seasonal low flows resulting in degradation of spawning and rearing areas and water quality (WDF 1975). A major limiting factor in the Chehalis basin is degraded water quality. The Chehalis River basin is reportedly degraded by fecal bacterial and unknown agents from sources including industrial, municipal, and pasture land uses, and from timber harvesting, residential wastewater, and other unknown sources (LCCD 1992a).

The Chehalis River from its mouth upstream to the Newaukum River confluence at RM 75.4 is reportedly impaired by fecal bacteria and low dissolved oxygen (LCCD 1992a). From its confluence with the Satsop River upstream to the city of Chehalis, the river has a history of fish kills associated with high temperatures and low dissolved oxygen levels. Elevated temperatures (in excess of 18°C) have been measured throughout the Chehalis River system in most years, resulting in water quality problems that restrict anadromous fisheries in this basin (LCCD 1992a and 1992b). Elevated temperatures and depressed dissolved oxygen levels typically occur during the summer season (LCCD 1992a). Despite the limiting factors associated with water quality in the lower Chehalis River, better fisheries habitat is found in the area downstream of the confluence of the Black River at RM 47.0, as compared to the upper Chehalis basin (Seiler 1989).

High occurrences of the diagenic fluke *Nanophyetus salmincola* are present in lower areas of the Chehalis River. Adult coho salmon migrating through the lower reaches become heavily infested with this parasite that places physiological burdens on the fish and increases their vulnerability to additional stress, and may increase mortality (WDF 1992).

It appears that degraded water quality and heavy parasite infestation cause exceptionally high mortality in the Chehalis River coho salmon smolts. Another factor that limits salmon production is the presence of a robust population of squawfish, known predators of juvenile salmonids, in the lower Chehalis River (WDF 1992).

Groundwater helps sustain stream flow during low flow (basal flow) conditions, which typically occur during the summer months. Groundwater problem areas are evident in Grays Harbor County near Elma. Typical causes of groundwater contamination include septic systems, agricultural waste (manure and pesticides), automotive waste, landfills, and industrial waste (LCCD 1992a). Contaminated groundwater is probably a contributing factor in water quality impairment in the lower Chehalis River basin.

Fish

Table 3.4-2 lists all fish species that occur within the study area. Six species of anadromous salmonids, Chinook salmon (*Oncorhynchus tshawytscha*), coho salmon (*O. kisutch*), chum salmon (*O. keta*), steelhead trout (*O. mykiss*), coastal cutthroat trout (*O. clarki clarki*), and bull trout (*Salvelinus confluentus*), use the Chehalis River mainstem within the study area. Healthy populations of spring- and fall-run Chinook, coho, and chum salmon migrate through the aquatic study area, along with three stocks of winter-run steelhead and one stock of summer-run steelhead. A summer-run population of Chinook salmon is depressed (WDFW 2002 and 2008c).

TABLE 3.4-2
FISH SPECIES LIKELY TO OCCUR IN THE VICINITY OF THE STUDY AREA

Common Name[a]	Scientific Name
Anadromous Fishes	
Chinook salmon	*Oncorhynchus tshawytscha*
Coho salmon	*O. kisutch*
Chum salmon	*O. keta*
Steelhead trout	*O. mykiss*
Coastal cutthroat trout	*O. clarki clarki*
Bull trout	*Salvelinus confluentus*
Pacific lamprey	*Entosphenus tridentatus*
River lamprey	*Lampetra ayresi*
White sturgeon	*Acipenser transmontanus*
American shad (I)	*Alosa sapidissima*
Resident Fishes	
Mountain whitefish	*Prosopium williamsoni*
Prickly sculpin	*Cottus asper*
Coastrange sculpin	*Cottus aleuticus*
Riffle sculpin	*Cottus gulosus*
Reticulate sculpin	*Cottus perplexus*
Torrent sculpin	*Cottus rhotheus*
Three-spine stickleback	*Gasterosteus aculeatus*
Olympic mudminnow	*Novumbra hubbsi*
Northern pikeminnow	*Ptychocheilus oregonensis*
Peamouth	*Mylocheilus caurinus*
Speckled dace	*Rhinichthys osculus*
Nooksack dace	*Rhinichthys cataractae ssp.*
Redside shiner	*Richardsonius balteatus*
Common carp (I)	*Cyprinus carpio*
Largescale sucker	*Catostomus macrocheilus*
Western brook lamprey	*Lampetra richardsoni*
Largemouth bass (I)	*Micropterus salmoides*
Black crappie (I)	*Pomoxis nigromaculatus*
Bluegill (I)	*Lepomis macrochirus*
Pumpkinseed (I)	*L. gibbosus*
Warmouth bass (I)	*L. gulosis*
Rock bass (I)	*Ambloplites rupestris*
Yellow perch (I)	*Perca flavescens*
Brown bullhead (I)	*Ameiurus nebulosus*

a. I=Introduced species
The study area is defined as the within 2,000 feet the Ranney wells and 300 feet downstream of the discharge outfall.
Sources: Baker (2008), Henning (2004), Jeanes et al. (2003), Kelley (1997), McPhail (1969), USFWS (2004), WDF (1971), Wydoski and Whitney (2003), Mongillo and Hallock (1995, 1997, and 1999).

The Satsop and Skookumchuck/Newaukum stocks of winter-run steelhead are depressed while the Chehalis River stock of winter-run steelhead is healthy and the Chehalis River summer-run steelhead stock has an unknown status. Historically, summer-run steelhead have returned to the Chehalis in low numbers due to a lack of suitable habitat (WDFW 2002, WDW 1992). Coastal cutthroat trout are present and relatively common throughout the Chehalis River basin (WDFW 2000). Juvenile Chinook, coho, chum, steelhead, and coastal cutthroat are documented to rear in the aquatic study area, while chum salmon have been documented to spawn in the study area (WDFW 2008c). Chinook spawn in the headwaters of the Chehalis upstream of the aquatic study area and in larger tributaries, while chum, steelhead, and coho spawn primarily in medium-sized tributaries and the mainstem rivers. Coastal cutthroat primarily spawn in small tributaries. Bull trout have not been documented to reproduce in the Chehalis River basin, but small numbers of large adult anadromous bull trout from known coastal natal rivers north of Grays Harbor have been documented to enter the lower Chehalis River basin (Jeanes et al. 2003, USFWS 2004, WDFW 2004).

Other anadromous fish that have been documented as occurring in the Chehalis River in the vicinity of the aquatic study area are white sturgeon (*Acipenser transmontanus*), introduced American shad (*Alosa sapidissima*), Pacific lamprey (*Entosphenus tridentatus*), and river lamprey (*Lampetra ayresi*). Lamprey and shad spawn in the Chehalis River, while white sturgeon do not reproduce in the Chehalis River basin and are primarily produced in the lower Columbia River and perhaps other coastal rivers to the south of the Columbia River, such as the Sacramento River (Wydoski and Whitney 2003). In addition to the ten anadromous fish species documented to occur in the vicinity of the aquatic study area, eulachon (*Thaleichthys pacificus*) and longfin smelt (*Spirinchus thaleichthys*) have been documented to spawn in the Chehalis River, but it is unknown if they run upstream as far as the project vicinity. Green sturgeon (*Acipenser medirostris*) summer over in Grays Harbor between the months of May and October, but are not known to enter the Chehalis River or to spawn in the Chehalis basin (Moser and Lindley 2007).

Native resident fishes occurring in the aquatic study area (Table 3.4-2) include mountain whitefish (*Prosopium williamsoni*), five species of sculpin (*Cottus* spp.), three-spine stickleback (*Gasterosteus aculeatus*), Olympic mudminnow (*Novumbra hubbsi*), northern pikeminnow (*Ptychocheilus oregonensis*), peamouth (*Mylocheilus caurinus*), speckled dace (*Rhinichthys osculus*), the Nooksack form of the longnose dace (*R. cataractae* ssp.), western brook lamprey (*Lampetra richardsoni*), largescale sucker (*Catostomus macrocheilus*), and redside shiner (*Richardsonius balteatus*). Both resident and sea-run life histories of coastal cutthroat trout are present in the aquatic study area. There are also nine species of introduced fish, including carp as well as members of the sunfish, catfish, and perch families (Table 3.4-2).

Threatened and Endangered Species

Table 3.4-3 lists special status fish likely to occur in the vicinity of the aquatic study area. The bull trout is the only federally listed fish present in the aquatic study area. Bull trout have not been documented to reproduce in the Chehalis River basin, but small numbers of large adult anadromous bull trout from known coastal natal rivers north of Grays Harbor (the Quinault, Queets, and Hoh Rivers) have been documented to enter the lower Chehalis River and its major tributary rivers as far upstream as RM 47 between late April and mid-June (Jeanes et al. 2003, USFWS 2004, WDFW 2004). The entry of anadromous bull trout into the lower Chehalis River during the spring months, which is likely a foraging migration, coincides with the out-migration timing of Pacific salmon. Starting at age 3, coastal anadromous bull trout have been documented to leave their natal streams and enter the marine environment from December to March and return to their natal streams from April to July (Brenkman and Corbett 2005, Brenkman et al. 2007). During their marine migration, coastal bull trout have been documented to enter coastal estuaries and non-natal streams to overwinter and forage on out-migrating salmonid smolts (Brenkman and Corbett 2005, Brenkman et al. 2007). It is possible that anadromous bull trout occasionally overwinter in the Chehalis River basin, but high summer water temperatures likely force foraging bull trout to exit the Chehalis River basin by late June and not return to the basin until the winter out-migration from their natal streams to the marine environment.

TABLE 3.4-3
THREATENED, ENDANGERED, SENSITIVE, AND CANDIDATE FISH SPECIES AND SPECIES OF CONCERN LIKELY TO OCCUR IN THE STUDY AREA VICINITY

Common Name	Scientific Name	Federal Status	State Status
Bull trout	*Salvelinus confluentus*	T	C
Pacific lamprey	*Entosphenus tridentatus*	SOC	NA[b]
River lamprey	*Lampetra ayresi*	SOC	C
Olympic mudminnow	*Novumbra hubbsi*	NA[a]	S

Sources: USFWS (2008), NMFS (2008), WDFW (2008a and 2008b).
The *study area* is defined as the within 2,000 feet the Ranney wells and 300 feet downstream of the discharge outfall.
T – Threatened: A species likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range
SOC – Federal Species of Concern
C – State Candidate: A species that is under state review for possible listing as endangered, threatened, or sensitive.
a. NA – Not applicable: A species that has no federal status
b. N/A – Not applicable: Species has not yet been added to the state list

Pacific lamprey and river lamprey are federal species of concern and their status in the Chehalis River basin is undocumented. Olympic mudminnow are found throughout low gradient side channels and floodplain ponds and wetlands of the Chehalis River (Mongillo and Hallock 1999). Their state sensitive status is due to their limited distribution, which is in low elevation floodplain habitat that is frequently filled for development or agriculture. The native range of the Olympic mudminnow is confined to coastal lowlands of the western Olympic Peninsula, from Lake Ozette south to Grays Harbor and up the north side of the Chehalis River valley to the Skookumchuck and Black Rivers with occasional headwater transfers from the Black to the Deschutes River (Wydoski and Whitney 2003).

3.4.2.2 Impacts

Construction Impacts

Although there are no aquatic resources on the project site, or on the area proposed for construction laydown and access, the Certificate Holder will implement the already-approved erosion and sediment control plan to avoid sediment releases into nearby streams. Discharges from the Grays Harbor Energy Center will use the existing outfall structure, and therefore construction of a new outfall will not be necessary. Thus, there will not be a significant adverse impact due to construction of the power plant.

Operational Impacts

As with Units 1 and 2, water for Units 3 and 4 will be withdrawn from existing Ranney wells and transported to the site through an existing pipeline infrastructure system (see Section 3.3, Water, WAC 463-60-322, and Section 2.5, Water Supply System, WAC 463-60-165). Process water will continue to be delivered through the existing connection to the existing outflow line. The Grays Harbor Energy Center will continue to send its effluent back to the blowdown line via the existing connection downstream of the project intake. Effluent will continue to be discharged through the existing outfall in the Chehalis River. The discharge will meet the limitations of the existing NPDES Permit.

The Chehalis River in the vicinity of the project site is classified as "core summer salmonid habitat" (June 15 to September 15) with a 7-day average daily maximum temperature (7-DADMax) criterion for aquatic life use of 16ºC (WAC 173-201A-200). This criterion applies to Pacific salmon and trout spawning, juvenile emergence from spawning gravel, and adult holding; or foraging by adult or sub-adult bull trout that occurs during the summer season. A review of a long-term temperature monitoring station at Porter (RM 33.3) reveals temperature recordings exceeding 18ºC almost every day between June 26 and September 16 during the summer of 2001 with a high water temperature exceeding 20ºC on 33 days during that period (Chehalis Basin Partnership 2003). The maximum water temperature (7-DADMax) did not exceed the criterion of 16ºC during when bull trout are present in the Chehalis River basin (March through June), but frequently exceeded the temperature criterion during the late spring and summer months when other salmonids, such as coho and Chinook salmon and steelhead, are present in the Chehalis River mainstem in the vicinity of the project site.

The lowest recorded daily mean flow for the Chehalis River at Porter, WA was 166 cfs and the lowest daily mean flow for the Satsop River at Satsop, WA was 147 cfs (USGS 1999). A conservative lowest mean daily flow for the Chehalis River in the vicinity of the project site would be the total of these two low flows, or 313 cfs. The seven consecutive day low flow at the Porter gauge during the period 1953–1993 averaged 308 cfs (Smith and Wenger 2001).

If the 6.5 cfs of additional water is purchased or leased from an entity other than the PDA, the potential maximum withdrawal at the Ranney wells would increase from 29.2 cfs to 35.7 cfs, or from 20 cfs to 26.5 cfs during low flow conditions. Leasing 6.5 cfs of additional water from an entity other than the PDA could require transferring the water withdrawal upstream from the current withdrawal location as much as 4 miles. The reduction of 5.7 cfs (88 percent of 6.5 cfs) at the Ranney wells and the discharge of as much as 3 cfs of water above the Ranney wells at a temperature below 16ºC would not create a measurable change in river flow, depth, wetted area, or water temperature in the main stem of the Chehalis River at or below the vicinity of the project site where the lowest regulatory minimum base flow is 550 cfs (WAC 173-522-020) and the lowest recorded flows are greater than 300 cfs.

Anadromous adult or sub-adult individuals of the federally listed bull trout (threatened) occasionally forage in the Chehalis River mainstem between the March and June and also may over winter in the Chehalis River basin. Bull trout would only be present in the Chehalis River basin outside of the low flow period when average river water temperature is at or below the 7-

DADMax 16ºC thermal maximum (WAC 173-201A-200) for foraging adult and sub-adult bull trout.

The increased water withdrawal from the Ranney wells and discharge of stormwater and process effluent into the Chehalis River will not significantly impact water temperature or available aquatic habitat for resident and anadromous fishes or other aquatic life in the Chehalis River.

No significant impacts to aquatic resources from the use of this well are anticipated.

3.4.3 WILDLIFE

Wildlife investigations were conducted for the Grays Harbor Energy Center, including the pipeline corridor and the transmission line corridor. This information was used as a baseline, and updated information was collected in June 2008 for the construction laydown and access area. Presence and distribution information related to special status species was obtained from the US Fish and Wildlife Service and the Washington Department of Fish and Wildlife (USFWS 2008, WDFW 2008b). Additional data was reviewed to determine probable occurrence of wildlife species in the terrestrial study area (Henning 2004, Wahl et al. 2005, Smith et al. 1997, Johnson and Cassidy 1997, and Dvornich et al. 1997).

3.4.3.1 Existing Conditions

Plant Site and Laydown Area

The terrestrial study area is defined as the existing 22-acre site and the 10-acre laydown and access area, and the area 500 feet around the combined 32-acre site. There will be no construction or disturbance to the aquatic study area described in Section 3.4.2 and, as a result, the aquatic study area is not included in the wildlife analysis.

The existing site has been graded several times, is scarcely vegetated, and is covered in gravel. The 10-acre construction laydown area consists of roughly 50% grassland/agriculture and 50% coniferous forest habitat. All trees and grassland in the laydown area will be removed during construction.

Wildlife

Table 3.4-4 lists wildlife species likely to occur within the terrestrial study area.

TABLE 3.4-4
WILDLIFE SPECIES LIKELY TO OCCUR IN THE VICINITY OF THE STUDY AREA

Common Name	Scientific Name
Birds[a]	
Ring-necked pheasant (I)	*Phasianus colchicus*
Ruffed grouse	*Bonasa umbellus*
Sooty blue grouse	*Dendragapus fuliginosus*
Great blue heron	*Ardea herodias*
Turkey vulture	*Cathartes aura*
Sharp-shinned hawk	*Accipiter striatus*
Cooper's hawk	*Accipiter cooperii*
Northern goshawk	*Acipiter gentilis*
American kestrel	*Falco sparverius*
Merlin	*Falco columbarius*
Peregrine falcon	*Falco peregrinus*
Red-tailed hawk	*Buteo jamaicensis*
Rock Dove (I)	*Columba livia*
Band-tailed pigeon	*Patagioena fasciata*
Morning dove	*Zenaida macroura*
Barn Owl	*Tyto alba*
Western screech-owl	*Megascops kennicottii*
Great horned owl	*Bubo virginianus*
Northern pygmy-owl	*Glaucidium gnoma*
Spotted owl	*Strix occidentalis*
Barred owl	*Strix varia*
Short-eared owl	*Asio flammeus*
Northern saw-whet owl	*Aegolius acadicus*
Killdeer	*Charadrius vociferus*
Common nighthawk	*Chordeiles minor*
Vaux’s swift	*Chaetura vauxi*
Rufous hummingbird	*Selasphorus rufus*
Hairy woodpecker	*Picoides villosus*
Downy woodpecker	*Picoides pubescens*
Northern flicker	*Colaptes auratus*
Red breasted sapsucker	*Sphyrapicus ruber*
Pileated woodpecker	*Dryocopus pileatus*
Olive-sided flycatcher	*Contopus borelis*
Willow flycatcher	*Empidonax traillii*
Hammond's flycatcher	*Empidonax hammondii*
Northern shrike	*Lanius excubitor*
Hutton's Vireo	*Vireo huttoni*
Warbling Vireo	*Vireo gilvus*
Northern rough-winged swallow	*Stelgidopteryx serripennis*
Violet-green swallow	*Tachycineta thalassina*
Tree swallow	*T. bicolor*
Cliff swallow	*Pterochelidon pyrrhonota*
Barn swallow	*Hirundo rustica*
Purple martin	*Progne subis*
Gray jay	*Perisoreus canadensis*

Common Name	Scientific Name
Stellar’s jay	*Cyanocitta stelleri*
American Crow	*Corvus brachyrhynchos*
Common raven	*Corvus corax*
Black-capped chickadee	*Parus atricapillus*
Chestnut-backed chickadee	*Poecile rufescens*
Bushtit	*Psaltriparus minimus*
Red-breasted nuthatch	*Sitta canadensis*
Brown creeper	*Certhia americana*
Bewick’s wren	*Thryomanes bewickii*
Winter wren	*Troglodytes troglodytes*
Golden-crowned kinglet	*Regulus satrapa*
Ruby-crowned kinglet	*R. caledula*
Varied thrush	*Ixoreux naevius*
American robin	*Turdus migratorius*
Swainson’s thrush	*Catharus ustulatus*
European starling (I)	*Sturnus vulgaris*
Cedar waxwing	*Bombycilla cedrorum*
Yellow warbler	*Dendroica petechia*
Yellow-rumped warbler	*D. coronata*
Black-throated gray warbler	*D. nigrescens*
Townsend's warbler	*D. townsendi*
MacGillivray's warbler	*Oporornis tolmei*
Orange-crowned warbler	*Vermivora celata*
Wilson's warbler	*Wilsonia pusilla*
Common yellowthroat	*Geothlypis trichas*
Western tanager	*Pirnga ludoviciana*
Black-headed grosbeak	*Pheucticus melanocephalus*
Spotted towee	*Pipilo maculatus*
Savannah sparrow	*Passerculus sandwichensis*
Fox sparrow	*Passerella iliaca*
Song sparrow	*Melospiza melodia*
Lincoln's sparrow	*M. lincolni*
White-crowned sparrow	*Zonotrichia leucophrys*
White-throated sparrow	*Z. albicollis*
Golden-crowned sparrow	*Z. atricappilla*
Dark-eyed junco	*Junco hyemalis*
Western meadowlark	*Sturnella neglecta*
Brewer’s blackbird	*Euphagus cyanocephalus*
Brown-headed cowbird	*Molothrus ater*
House finch	*Carpodacus mexicanus*
Purple finch	*C. purpureus*
Red crossbill	*Loxia curvirostra*
Pine siskin	*Carduelis pinus*
American goldfinch	*Carduelis tristis*
Evening grosbeak	*Coccothraustes vespertinus*
House sparrow (I)	*Passer domesticus*
Mammals[b]	
American opossum	*Didelphis virginiana*
Montane shrew	*Sorex monticolus*

Common Name	Scientific Name
Trowbridge's shrew	*S. trowbridgii*
Vagrant shrew	*S. vagrans*
Shrew-mole	*Neurotrichus gibbsii*
Coast mole	*Scapanus orarius*
Townsend's mole	*S. townsendii*
California myotis	*Myotis californicus*
long-eared myotis	*M. evotis*
Long-legged myotis	*M. volans*
Yuma myotis	*M. yumanensis*
Little brown myotis	*M. lucifugus*
Big brown bat	*Eptesicus fuscus*
Hoary bat	*Lasirus cinereus*
Silver-haired bat	*Lasionycteris noctivagans*
Townsend's big-eared bat	*Coryhorhinus townsendii*
Snowshoe hare	*Lepus americanus*
Mountain beaver	*Aplodontia rufa*
Townsend's chipmunk	*Tamias townsendii*
Douglas' squirrel	*Tamiasciurus douglaasii*
Northern flying squirrel	*Glaucomys sabrinus*
Bushy-tailed wood rat	*Neotoma cinerea*
Forest deer mouse	*Peromyscus keeni*
Deer mouse	*P. maniculatus*
Gapper's red-back vole	*Clethrionomys gapperi*
Long-tailed vole	*Microtus longicaudus*
Creeping vole	*M. oregoni*
Townsend's vole	*M. townsendii*
Pacific jumping mouse	*Zapus trinotatus*
Porcupine	*Erethizon dorsatum*
House mouse	*Mus musculus*
Norway rat	*Rattus norvegicus*
Coyote	*Canis latrans*
red fox	*Vulpes vulpes*
Raccoon	*Procyon lotor*
Black bear	*Ursus americanus*
Striped skunk	*Mephitis mephitis*
Spotted skunk	*Spilogale gracilis*
Ermine	*Mustela erminea*
Long-tailed weasel	*Mustela frenata*
Bobcat	*Lynx rufus*
Columbia black-tailed deer	*Odocoileus hemionus columbianus*
Roosevelt Elk	*Cervus canadensis roosevelti*
Amphibians[c]	
Pacific treefrog	*Pseudacris regilla*
Northern red-legged frog	*Rana aurora*
Western toad	*Bufo boreas*
Rough-skinned newt	*Taricha granulosa*
Northwestern salamander	*Ambystoma gracile*
Long-toed salamander	*Ambystoma macrodactylum*
Western red-backed salamander	*Plethodon vehiculum*

Common Name	Scientific Name
Ensatina	*Ensatina eschscholtzii*
Reptiles[d]	
Common garter snake	*Thamnophis sirtalis*
Northwestern garter snake	*T. ordinoides*
Western terrestrial garter snake	*T. elegans*
Rubber boa	*Charin bottae*
Northern Alligator lizard	*Elgaria coerulea*

The study area is defined as the combined 32-acre site and 500 feet surrounding it.
I=Introduced species
a. Source: Wahl et al. (2005), Smith et al. (1997)
b. Source: Johnson and Cassidy (1997)
c. Source: Dvornich et al. (1997), Henning (2004)
d. Source: Dvornich et al. (1997)

Threatened and Endangered Species

Table 3.4-5 lists special status wildlife likely to occur in the vicinity of the terrestrial study area. The northern spotted owl (*Strix occidentalis*) is the only federally listed (threatened) wildlife species likely to occur in the terrestrial study area. This species depends on large stands of mature and old-growth forest. Surveys for the northern spotted owl were conducted in mature forest habitat at the Satsop Development Park in 1993 and 1994 by qualified biologists from the Washington State DNR. The surveys were designed to meet US Fish and Wildlife Service protocol. No spotted owls were detected during these surveys (Welker 1993, Schinnell 1994).

TABLE 3.4-5
THREATENED, ENDANGERED, SENSITIVE, CANDIDATE WILDLIFE SPECIES AND SPECIES OF CONCERN LIKELY TO OCCUR IN THE STUDY AREA VICINITY

Common Name	Scientific Name	Federal Status	State Status
Long-eared myotis	*Myotis evotis*	SOC	NA[b]
Long-legged myotis	*Myotis volans*	SOC	NA[b]
Townsend's big-eared bat	*Coryhorhinus townsendii*	SOC	C
Oregon vesper sparrow	*Pooectetes gramineus affinis*	SOC	C
Bald eagle	*Haliaeetus leucocephalus*	SOC	S
Northern goshawk	*Accipiter gentiles*	SOC	C
Northern Spotted owl	*Strix occidentalis*	FT	E
Vaux's swift	*Chaetura vauxi*	NA[a]	C
Pileated woodpecker	*Dryocopus pileatus*	NA[a]	C
Olive-sided flycatcher	*Contopus cooperi*	SOC	NA[b]
Purple martin	*Progne subis*	NA[a]	C
Western toad	*Bufo boreas*	SOC	C

The study area is defined as the proposed plant and 500 feet around it.
Sources: Data from Natural Heritage Data Systems, WDFW (2008a and 2008b), USFWS (2008)
C – State Candidate: A species that is under review for possible listing as endangered, threatened, or sensitive.
E – State Endangered: A species, native to the state of Washington, that is likely seriously threatened with extirpation throughout all or a significant portion of its range.
FT – Federal Threatened Species
S – State Sensitive: A species native to the state of Washington that is vulnerable or declining and likely to become endangered or threatened throughout a significant portion of its range within the state without cooperative management or removal of threats.
SOC – Federal Species of Concern
a. N/A – Not applicable - A species that has no federal status
b. N/A– Not applicable - A species that is has not yet been added to the state list.

There is habitat in the vicinity of the terrestrial study area that would support foraging spotted owls; however, there is insufficient evidence to establish territory. The edge of a spotted owl management circle is approximately 0.75 mile east of the project site. No spotted owls have been observed in the project vicinity. The patches of coniferous forest within the laydown area are large enough for thinning and limited harvest, but do not constitute a mature, old-growth coniferous forest with the complex structure necessary for northern spotted owl nesting, roosting, and foraging. Therefore, other than individual owls occasionally dispersing through the area to establish territories elsewhere, northern spotted owls are unlikely to occur in the terrestrial study area.

Although there is a federally listed (threatened) marbled murrelet (*Brachyramphus marmoratus*) buffer a little more than 1 mile northwest of the project site, no marbled murrelets have been observed in the project vicinity. Unlike the spotted owl, marbled murrelets would not forage within the terrestrial study area, confining their foraging activities to coastal marine waters. None of the trees within the terrestrial study area are large enough to provide suitable nesting for either species.

There are eight federal species of concern that may occur in the vicinity of the terrestrial study area. Of these, three species of bats may forage over the terrestrial study area, but suitable roosting, nursery, or hibernation sites are not available in the project vicinity for Townsend's big-eared bat (*Coryhorhinus townsendii*). The long-eared myotis (*Myotis evotis*) and long-legged myotis (*M. volans*) may make limited use of conifer trees as roost sites. Only the Townsend's big-eared bat (state candidate) has special state status. The bald eagle (*Haliaeetus leucocephalus*) is a state sensitive species, with the closest mapped nest approximately 1.5 miles northeast of the study area. It has been confirmed that there are no bald eagle nests, roosts, or perch trees in the terrestrial study area or vicinity (M. Zahn, personal communication). Hence, eagle use of the project vicinity is limited to opportunistic foraging by bald eagles flying over the project site. The Oregon vesper sparrow (*Pooectetes gramineus affinis*), northern goshawk (*Accipiter gentiles*), and western toad (*Bufo boreas*) are state candidate species that may occur within the vicinity of the study area. The final federal species of concern is the Olive-sided flycatcher (*Contopus cooperi*), which does not have any special state status.

Finally, three state candidate species, Vaux's swift (*Chaetura vauxi*), Pileated woodpecker (*Dryocopus pileatus*), and purple martin (*Progne subis*), that have no federal status may occur in the vicinity of the terrestrial study area. Signs of pileated woodpecker foraging activity was observed in forested stands near Fuller Creek, to the east of the terrestrial study area.

3.4.3.2 Impacts

Construction

Approximately 5 acres of coniferous forest habitat and 5 acres of grassland/agriculture would be removed within the laydown area and would disturb wildlife in the laydown area. Because of its proximity to the existing Grays Harbor Energy Center and its separation from other forest land by the BPA right-of-way on the south, the annually mown grassland to the east, and a roadway to the north, this loss of 5 acres of habitat is considered a minor impact. Human activity and noise generated from construction of Units 3 and 4 will be temporary and result in temporary disturbance of wildlife in immediately surrounding habitat areas. Wildlife tends to habituate, so only minor impacts are expected to occur.

Operation

Baseline noise level for forested habitat is 40 A-weighted decibels (dBA) (WSDOT 2008). Nesting birds are the most likely wildlife to be affected by operational noise in the vicinity of the project site. Based on a study of 17 species of birds, the average threshold level where a sound increase is detectable but no reaction occurs is 4 dB above baseline noise level. The threshold level where birds show apparent interest (alert) by turning the head or extending the neck is 17 dB above baseline and the threshold level where birds show avoidance of the sound by hiding, defending themselves, moving their wings or body, or postponing a feeding (disturbance) is 30 dB. Adding the baseline level of 50 dBA to the threshold increases yields a detection level of 44 dBA, alert level of 57 dBA, and disturbance level of 70 dBA. The threshold of injury level, where a bird is actually injured by flushing from the nest or the young missing a feeding, is defined as 92 dBA, regardless of the baseline noise level.

Based on the information presented in Section 4.1, Environmental Health, WAC 463-60-352, operational noise will alert nesting birds in the area immediately surrounding the project site. Noise will only reach the threshold of the disturbance level within the property boundaries. The threshold of injury will not be reached within the project area. Nesting birds within the area outside the property line that exceeds the threshold 57 dBA will be affected, but not disturbed or injured by operational noise. Small mammals and deer may have similar levels of noise related impacts.

There were no bald eagle nests found near the study area, therefore no buffers or timing restrictions are needed.

No special wildlife use areas, such as fawning areas, seasonal congregation areas, or critical seasonal use habitats have been reported adjacent to the study area, and none were noted during fieldwork. It is possible that fawning areas may exist and are unknown.

Construction and maintenance vehicle traffic may cause mortality among some individual animals as they cross the access roads. These impacts generally will affect a very small percentage of the existing animal populations, and therefore the impacts will not be significant.

No spotted owls have been detected during surveys in mature forest habitat of the Satsop Development Park property. No other stands of mature or old-growth forest are located in the study area.

There are no wetlands or water bodies on the project site. Therefore, there would be no impacts to species relying on those habitats. The previously graded 22 acres of the project site has minimal vegetation and marginal if any current habitat value. There would be a permanent impact from the removal of the 5 acres of forest habitat and 5 acres of grassland/agriculture habitat on the construction laydown and access area. The state listed wildlife in the vicinity of the study area may be temporarily displaced due to either the construction or operational noise.

Signs of pileated woodpecker foraging activity was observed in forested stands near Fuller Creek, but no long-term impacts are anticipated with either the construction or operation of the plant. None of the remaining listed wildlife have been documented on site or within the study area by Washington Department of Fish and Wildlife.

3.4.4 MITIGATION MEASURES

No significant impacts to habitat, fish, or wildlife are anticipated to occur from the construction and operation of Units 3 and 4, or in combination with the operation of the existing Units 1 and 2, and no mitigation measures are required.

SECTION 3.5 WETLANDS (WAC 463-60-333)

Biologists surveyed the vegetation, focusing primarily on the areas potentially affected by construction activities. A wetland reconnaissance was conducted in conjunction with vegetation surveys.

3.5.1 EXISTING CONDITIONS

On June 19, 2008, URS biologists conducted a wetland reconnaissance and vegetation survey on the 10-acre construction laydown and access area to the east of the existing 22-acre site.

3.5.1.1 Regional Conditions

The study area is located within the Puget Trough Province (Franklin and Dyrness 1988). Relief is moderate, with elevations seldom exceeding 525 feet above msl. The majority of the soils were formed in glacial materials under the influence of coniferous forest vegetation.

3.5.1.2 Plant Site

Prior to the construction of the Grays Harbor Energy Center, most of the 22-acre project site had been filled and graded with several feet of compacted gravel (Parametrix 1993), lacked vegetation, and a portion of the site was covered with asphalt. The site was used as a construction laydown area and had stockpiles of concrete forms, steel reinforcing bars, and other materials remaining from construction of the nuclear facilities located on the Satsop Power Plant property. The site was completely regraded for the Grays Harbor Energy Center, including the portion of the site that would be used for the construction and operation of Units 3 and 4.

The area immediately surrounding the plant site is a mix of developed and undeveloped areas. The area north of the site is industrial with some conifers to the northeast. The area south of the project site consists of the transmission line corridor and is mostly brush, followed by conifers further south. Keys Road lies immediately west of the project site. The 10-acre construction laydown and access area east of the existing project site consists of approximately 5 acres of thinned conifers managed as a mature forest, and approximately 5 acres of grassland/agriculture that is mowed every year. Further to the east is a continuation of the grassland area that is mowed every year.

No wetlands were found on the existing 22-acre site or the construction laydown and access area to the east.

3.5.2 IMPACTS

Construction and operation of Units 3 and 4 will not affect wetlands because there are no wetlands on the existing site or in the area proposed for construction laydown and access.

3.5.3 MITIGATION MEASURES

No impacts to wetlands will occur and no mitigation measures are required.

SECTION 3.6 ENERGY AND NATURAL RESOURCES (WAC 463-60-342)

3.6.1 INTRODUCTION

Energy and natural resources are consumed during construction and operation of any facility. Because the proposed Units 3 and 4 will generate electricity, it will produce many times more energy than is invested in its materials or is used to construct them. Thus, the focus of this section is on the operational aspect of the facility expansion.

3.6.2 ENERGY REQUIRED

3.6.2.1 Construction

Cranes, trucks, mobile equipment, and power tools will all consume energy during project construction. Similarly, energy is used during manufacturing of the combined cycle equipment and materials necessary for constructing the new units. For example, the steel used in much of the equipment requires energy input during the foundry, rolling mill, and fabrication processes. Until the project's detailed design has been completed, estimates of materials content and manufacturing energy use cannot be made; however, the purpose of the combustion turbine facility will be to produce electrical and steam energy over a planned project lifetime of at least 30 years. During this time the Grays Harbor Energy Center will produce approximately 171 million MW-hours of electricity, an amount far in excess of the energy required for production of the materials used in the manufacture and fabrication of the equipment used in the project.

3.6.2.2 Operation

The Grays Harbor Energy Center will continue to be fueled by natural gas. A small amount of diesel fuel (#2 distillate) will be on site for the backup generators and fire-water pump.

Natural gas will continue to be delivered to the project by the existing natural gas pipeline installed for Units 1 and 2. Natural gas will continue to flow from the pipeline through a metering/pressure-regulating station located on the northern boundary of the project site.

The expanded Grays Harbor Energy Center will require a maximum of 103,048 pounds per hour of natural gas to fuel each combustion turbine and duct burner, for a total maximum consumption of 412,192 pounds per hour. Annually, a maximum of 3.6 billion pounds of natural gas will be used to fuel the expanded project, assuming 8,760 hours of operation per unit. The auxiliary boilers will use a maximum of 1,254 pounds per hour of natural gas. Annually, a maximum of 6.3 million pounds of natural gas will be used to fuel the auxiliary boilers assuming 2,500 hours of operation per boiler. Assuming a 30 -year project life, the Grays Harbor Energy Center will require a maximum of 108 billion pounds of natural gas to generate a maximum of 342 million MW-hours of electricity.

Distillate fuel oil will be used to operate the emergency backup diesel generators. Each diesel generator uses 40.4 gallons of distillate fuel per hour of operation, resulting in a maximum annual consumption rate to operate the diesel generators of 2,101 gallons of fuel oil per year, based on 26 hours of operation for each diesel generator.

3.6.3 SOURCE AND AVAILABILITY OF ENERGY AND NATURAL RESOURCES

The project's fuel will continue to be natural gas that will be supplied by the pipeline constructed as part of the original project. A final determination of the fuel source will be made after final commitment for construction, is likely to be drawn from both domestic and Canadian sources. The suppliers have sufficient gas available to provide for the needs of the project and other customers over the 30-year life of the project.

3.6.4 NONRENEWABLE RESOURCES

3.6.4.1 Construction

Construction of Units 3 and 4 will require use a variety of natural resources, although in relatively small amounts. The largest quantities will be of steel (from iron ore) and concrete (from aggregate, sand and cement). Diesel fuel and electrical power also will be consumed during construction.

3.6.4.2 Operation

The main resource consumed by operation of Units 3 and 4 will be natural gas.

In addition, operation of Units 3 and 4 will entail consumption of minor amounts of other materials, such as metals, petroleum-based lubricants, paints, and various chemicals used in the process of operation and normal maintenance of the plants.

3.6.5 CONSERVATION AND RENEWABLE RESOURCES

Compared with many other sources of electricity, the Grays Harbor Energy Center will conserve energy. The facility is expected to operate at approximately 54 to 54.5 percent efficiency across the ambient temperature range, compared to 30 to 45 percent efficiency for other types of thermal plants. A discussion of water reuse can be found in Section 2.8, Wastewater Treatment, WAC 463-60-195.

Large combined cycle gas-fired power plants also provide the benefit of integrating large amounts of variable, intermittent wind generation resources by providing a firm backup resource in times when wind speeds are less than optimal for energy generation.

3.6.6 SCENIC RESOURCES

Impacts to scenic resources are described in Section 4.2, Land and Shoreline Use, WAC 463-60-362.

As shown on Figure 5.1-4 *Locations of Class I Areas and the CRGNSA within the AQRV Modeling Domain* in Section 5.1 PSD Application, four Class I areas are located within 160 kilometers (100 miles) of the project site: Mt. Rainier National Park, Goat Rocks Wilderness Area, Alpine Lakes Wilderness Area, and Olympic National Park. The Class I area closest to the proposed Grays Harbor Energy Center is Olympic National Park, located approximately 58 kilometers (35 miles) to the northeast. Other Class I areas considered in the modeling analysis are Pasayten Wilderness, Glacier Peak Wilderness, Mt. Adams Wilderness, and the Mt. Hood Wilderness. At the request of the US Forest Service, the analysis also considers impacts to the Mt. Baker Wilderness and the Columbia River Gorge National Scenic Area. Results of the CALPUFF dispersion modeling performed for the proposed project show that concentrations of pollutants from all four units are below the Class I allowable increment for the nearest Class I area and thus are not expected to have a significant impact upon these scenic resources. Additionally, the regional haze analyses show minimal impact from the project.

Visual impacts of Units 3 and 4 upon the existing regional landscape are not expected to be significant. A small portion of the emission stacks may be visible from some viewpoints in the Chehalis River Valley. If visible, the presence of small portions of the project's emission stacks will be an additional, but minor, element to the west of the existing and taller cooling towers of WNP-3 and WNP-5, and the existing stacks of Units 1 and 2. Depending on the time of year and weather conditions, attention to the stacks could be more pronounced when a vapor plume is present.

The impact to local residents adjacent to the site is expected to be slightly negative but not significant, due to the overall visual compatibility with the existing conditions. Even though the emission stacks and the higher plant structures will be visible, Units 3 and 4 will be an addition to the existing Grays Harbor Energy Center. The vegetated screening berm and turbine equipment enclosures also will reduce visual impacts.

4.0 BUILT ENVIRONMENT

SECTION 4.1 ENVIRONMENTAL HEALTH (WAC 463-60-352)

4.1.1 NOISE

In support of the permitting effort for the addition of Units 3 and 4 to the Grays Harbor Energy Center, an assessment was conducted to examine potential noise impacts. The assessment consisted of: (1) identifying all sensitive receivers in the vicinity of the Grays Harbor Energy Center site potentially impacted by noise; (2) monitoring existing ambient noise levels at these locations; (3) predicting project noise levels at the property boundary and at off-site receivers using three-dimensional computer modeling techniques; (4) comparing projected noise levels to various impact criteria including State of Washington performance standards; and (5) incorporating appropriate noise controls into the design of the plant to minimize any potential impact.

Results of the analysis showed that facility noise levels are expected to fully comply with requirements established by the State of Washington (70 dBA at adjacent industrial properties; 50 dBA at nearby residences), given the proposed acoustical design of Units 3 and 4, which includes combustion turbine generator (CTG) air intake silencers, high-performance CTG acoustical enclosures, CTG ventilation system silencers, CTG exhaust silencers, and acoustical barriers. Moreover, noise levels are not expected to cause pure tones or annoyance due to low-frequencies. [1]

The acoustical terminology and concepts used in this analysis are included in Appendix B.

4.1.1.1 Regulatory Controls

The Washington Administrative Code, Chapter 173-60, which EFSEC has adopted as the noise standards for facilities under its jurisdiction (WAC 463-62-030), limits environmental noise according to the land use classifications of both the noise emitting property and the receiving property, as presented in Table 4.1-1. Classes A, B, and C generally correspond to residential, commercial, and industrial or agricultural areas, respectively. Furthermore, between the hours of 10 pm and 7 am, the noise limitations for Class A receiving properties are reduced by 10 decibels.

[1] Initial results of recent noise monitoring of existing Units 1 and 2 indicate that noise levels comply with WAC standards. A separate assessment report documenting these results will be prepared and submitted for EFSEC review.

TABLE 4.1-1
MAXIMUM PERMISSIBLE ENVIRONMENTAL SOUND LEVELS

EDNA of Noise Source	Maximum Permitted Sound Level by EDNA of Receiving Source (dBA)		
	Class A	Class B	Class C
Class A	55	57	60
Class B	57	60	65
Class C	60	65	70

Source: Washington State Department of Ecology Noise Regulations, Chapter 173-60.
EDNA – Environmental Designation for Noise Abatement
Class A: Residential areas or lands where human beings reside and sleep; such as residential areas, multiple family living areas, recreational and entertainment areas (e.g., camps, parks, resorts), community service areas (e.g., retirement homes, hospitals, health and correctional facilities).
Class B: Commercial areas or land uses requiring protection against noise interference with speech; such as commercial living and dining areas, motor vehicle services, retail services, banks, office buildings, and commercial and recreational areas not used for human habitation (e.g., theaters, stadiums, fairgrounds, amusement parks, and educational, religious, governmental, and cultural facilities).
Class C: Industrial areas or lands involving economic activities; such as agricultural, storage, warehouse, production, and distribution facilities.

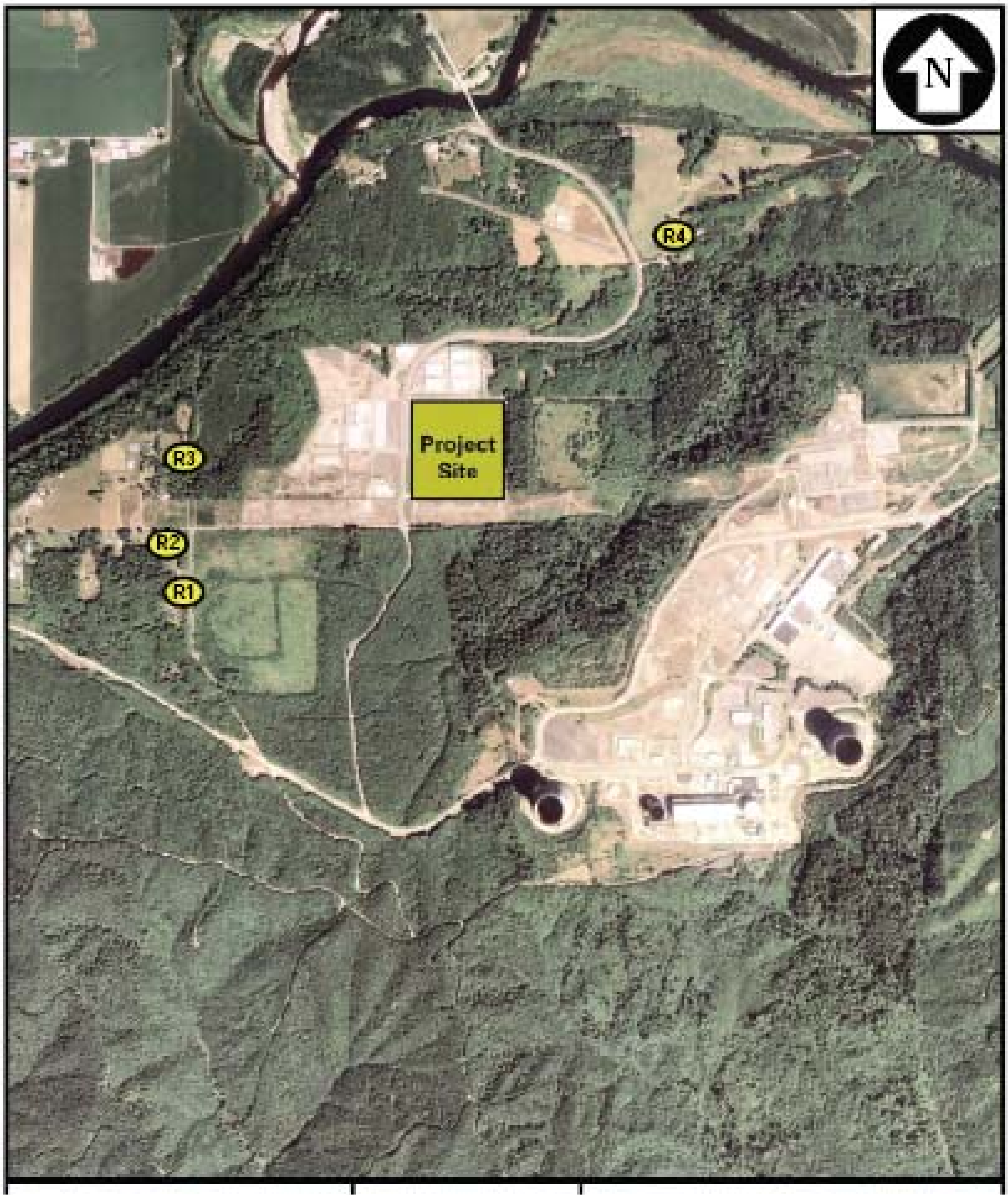
4.1.1.2 Existing Conditions

The Grays Harbor Energy Center is sited along Keys Road, between the Chehalis River and Fuller Creek, in Grays Harbor County in the State of Washington, as depicted in Figure 2.1-1. The land immediately adjacent to the site includes wooded areas, and industrial and commercial uses, including a transmission line easement to the south. Units 3 and 4 would be constructed entirely within the boundaries of the approximately 22-acre Grays Harbor Energy Center site. A 10-acre site immediately east of the project site would be used for construction laydown and access and would become part of the overall site boundary. The 10-acre site is covered with approximately 5-acres of thinned conifers and 5-acres of grassland/agriculture that is mowed every year. For noise assessment purposes, the eastern property boundary will include this 10-acre expansion area.

Nearby residences exist approximately 2,200 feet west of the site along Keys Road West, and approximately 1,900 feet northeast of the site along Fuller Road. These residences are identified in Table 4.1-2 and shown in Figure 4.1-1.

TABLE 4.1-2
NEAREST NOISE-SENSITIVE RECEIVERS

Location	Distance from Project Site	Description
R1	2,250 Feet	20 Keys Road South
R2	2,200 Feet	Southeast Corner of Keys Road West and Keys Road South
R3	2,200 Feet	North of Access Road Gate
R4	1,900 Feet	Southeast Corner of Fuller Road and Keys Road



Source: Michael Theriault Acoustics Inc.

Figure 4.1-1
Noise Sensitive Receivers

Ambient Survey Instrumentation

Noise measurements were taken at four locations as shown in Figure 4.1-2. All measurements were conducted using precision real time sound analyzers and microphones conforming to Type 1 tolerance requirements of the American National Standards institute (ANSI S1.4 – General Purpose Sound Level Meters). All instrumentation was within its laboratory calibration period, and appropriate calibration settings were verified in the field.

Ambient Monitoring Results

Daytime ambient noise levels (7 am to 10 pm) were generally controlled by vehicle traffic on Keys Road, Keys Road West, Keys Road South, Irwin Lane, and Fuller Road, as well as by wood processing activity, and residential activity. Ambient levels were influenced to a lesser degree by intermittent sources including dog barks, bird song, and aircraft flyovers. Nighttime noise levels (10 pm to 7 am) did not appear to be significantly influenced by man-made sources.

As shown in Table 4.1-3, daytime ambient noise levels (L_{EQ}) ranged from 32 dBA to 60 dBA at nearby residences, whereas nighttime ambient noise levels (L_{EQ}) ranged from 26 dBA to 45 dBA.

4.1.1.3 Impacts

Noise levels from the project will be relatively steady and continuous. Because the WAC noise limits apply to the total noise levels from both the existing Units 1 and 2 and the additional Units 3 and 4, noise levels from the entire facility (Units 1 through 4) were used for this analysis.

The Grays Harbor Energy Center is considered a Class C emitter. Since it may operate 24-hours per day, Units 3 and 4 will be designed to achieve more stringent nighttime limits (50 dBA) at Class A (residential) receivers. Since land uses adjacent to the facility site are industrial and agricultural, a limit of 70 dBA will apply at the property boundaries, which includes the additional 10-acre site on the east.

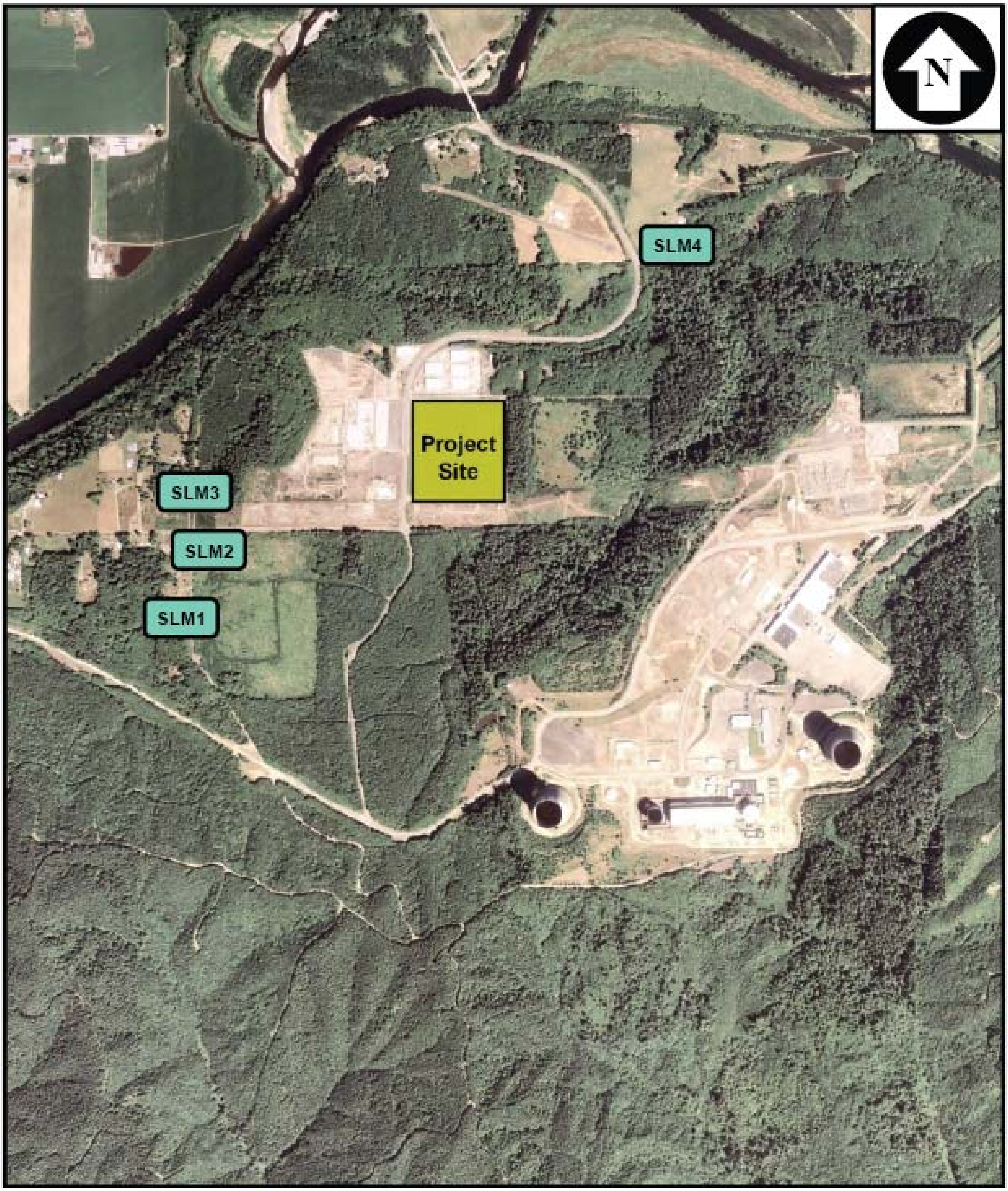
Additional Impact Criteria

Grays Harbor Energy Center noise levels were also evaluated in terms of low-frequency noise impact, and potential for tonality, as described below.

Low-Frequency Noise Impact: The State of Washington has not established specific guidelines for low-frequency noise impacts. For purposes of assessing potential impacts, American National Standards Institute (ANSI) Standard B133.8-2, "Gas Turbine Installation Sound Emissions", was used to evaluate project noise levels. To address low frequency noise, Annex B of this standard recommends that noise levels not exceed 75-80 dBC.[2]

---

[2] C-weighted levels (dBC) are generally considered a better indicator of perceived low-frequency noise, as compared to only A-weighted levels which emphasize mid- to high-frequencies.



Source: Michael Theriault Acoustics Inc.

Figure 4.1-2
Noise Monitoring Locations

Table 4.1-3
PRE-EXISTING AMBIENT SOUND LEVELS (dBA)

Location	Description	Time Period	Range of Hourly L_{EQ} Levels
SLM1	20 Keys Road South	Daytime	35-54
		Nighttime	27-37
SLM2	Intersection of Keys Road West and Keys Road South	Daytime	45-60
		Nighttime	26-45
SLM3	Access Road Gate	Daytime	32-44
		Nighttime	26-36
SLM4	Intersection of Fuller Road and Keys Road	Daytime	40-48
		Nightime	37-44

Note: Daytime is 7 am – 10 pm; Nighttime is 10 pm to 7 am

Tonality: For purposes of this assessment, pure tones exist when any octave-band noise level exceeds that of its adjacent octave-bands by more than three decibels.

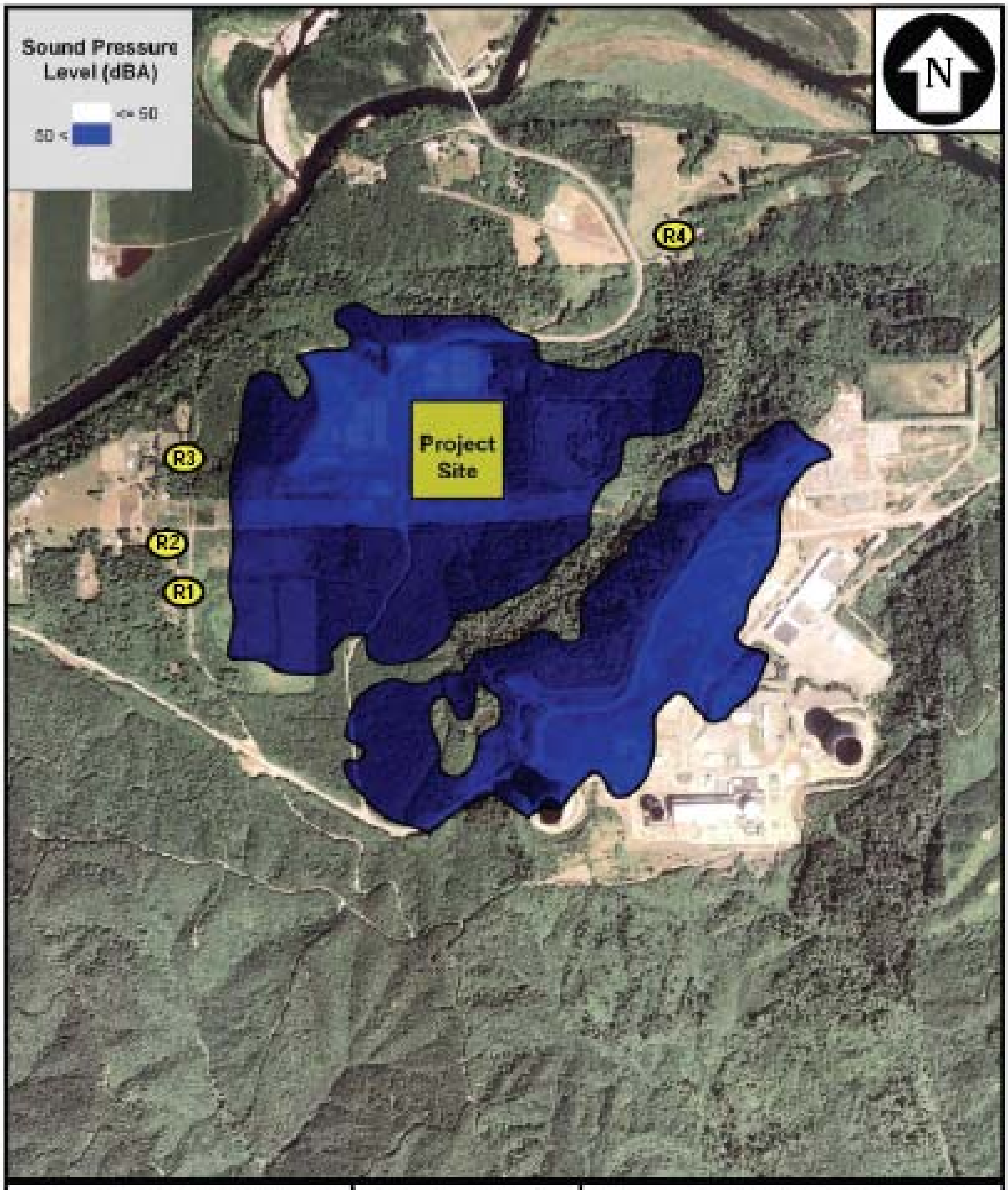
Operational Noise Levels

Total project A-weighted noise levels (Units 1 through 4) at nearby receivers are expected to range from 45 dBA to 49 dBA, and C-weighted noise levels are expected to range from 62 dBC to 65 dBC (Table 4.1-4). Predicted off-site noise levels also are shown in Figure 4.1-3.

TABLE 4.1-4
PREDICTED TOTAL PROJECT NOISE LEVELS AT NEARBY RESIDENCES

Location	A-Weighted dBA	C-Weighted dBC
Receiver 01	48	65
Receiver 02	49	65
Receiver 03	48	64
Receiver 04	45	62

Total project noise levels (Units 1 through 4) are expected to range from 56 dBA to 70 dBA at the property boundary (Table 4.1-5). Predicted property boundary noise levels also are shown in Figure 4.1-4.

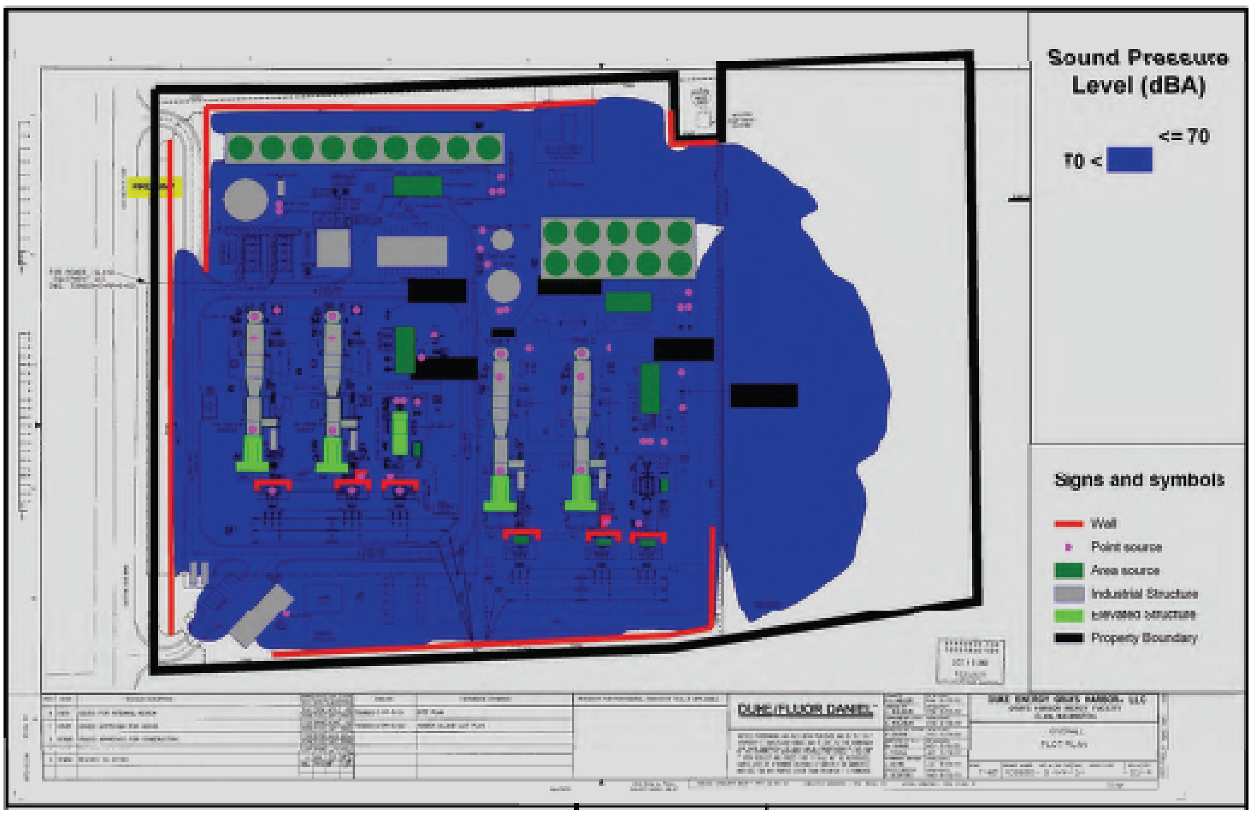


Source: Michael Theriault Acoustics Inc.

Figure 4.1-3
Predicted Off-Site Noise Level Contours

TABLE 4.1-5
PREDICED TOTAL PROJECT NOISE LEVELS AT SITE PROPERTY BOUNDARY

Location	Range of A-Weighted Levels
Property Line – North	59 - 70
Property Line – East	65 - 68
Property Line – South	65 - 70
Property Line – West	56 - 65



Source: Michael Theriault Acoustics Inc.

Figure 4.1-4
Predicted On-Site Noise Level Contours and Conceptual Barrier Layout

Operational Noise Impact Assessment

Table 4.1-6 compares the predicted noise levels at nearby residences and at the project property lines with the WAC permissible noise level.

TABLE 4.1-6
WAC NOISE ASSESSMENT (dBA)

Location	Predicted Project Noise Level	WAC Permissible Noise Level	Complies with WAC?
Receiver 01	48	50	Yes
Receiver 02	49	50	Yes
Receiver 03	48	50	Yes
Receiver 04	45	50	Yes
Property Line – North	70	70	Yes
Property Line – East	68	70	Yes
Property Line – South	70	70	Yes
Property Line – West	65	70	Yes

The maximum predicted noise level at nearby residences is 49 dBA, as presented in Table 4.1-6, or one decibel below the permissible level of 50 dBA. As such, noise levels are expected to fully comply with WAC requirements at the nearest residential receivers during operation of the existing Units 1 and 2 combined with the proposed Units 3 and 4.

The maximum predicted noise level at the property boundary is 70 dBA (Table 4.1-6). As such, noise levels are expected to fully comply with WAC requirements at adjacent industrial properties during operation of the existing Units 1 and 2 combined with the proposed Units 3 and 4.

Low-Frequency Noise Annoyance

As shown in Table 4.1-4, the maximum predicted C-weighted level at the nearest noise-sensitive receivers is 65 dBC, or ten decibels lower than the recommended maximum level (75 dBC). Given this, no significant impact is expected due to low-frequency noise levels from the project.

Tonal Assessment

Although it is difficult to predict with certainty whether pure tones will be perceptible at the nearest residential points of reception, at no receiver location is any octave-band noise level expected to exceed that of its adjacent octave-bands by more than three dB. Based on this finding, no pure tones are expected.

4.1.1.4 Construction Noise Impact Assessment

Like most projects, construction of Units 3 and 4 would result in increased noise levels for a limited period of time. Noise levels would vary widely, depending on the phase of construction and specific tasks being performed. For example, during site preparation, heavy equipment for grading, excavation and pad construction would be required, including shovels, front-end loaders, dump trucks and concrete trucks. Alternately, on-site fabrication during the equipment installation phase would require portable generators, air compressors, welding machines, etc.

Typical noise levels of construction equipment that may be employed during the construction process are given in Table 4.1-7.

TABLE 4.1-7
TYPICAL NOISE LEVELS FOR CONSTRUCTION EQUIPMENT

Equipment Item	Noise Level at 50 Feet (dBA)	Equipment Item	Noise Level at 50 Feet (dBA)
Air Compressors	76 – 89	Generators (Portable)	71 – 87
Backhoes	81 – 90	Jackhammers	69 – 85
Concrete Batch Plant	80 – 85	Rock Drills	83 – 99
Concrete Pumps	74 – 84	Pile Drivers	81 – 107
Concrete Vibrators	68 – 81	Pumps	68 – 80
Cranes (Derrick)	79 – 86	Steel Rollers	75 – 82
Cranes (Mobil)	80 – 85	Shovels	77 – 90
Dozers	77 – 90	Trucks	81 – 87
Front-End Loaders	77 – 90	Vibratory Conveyors	70 – 80
Graders	79 – 89	Welders	66 – 75

Source: Bolt, Beranek, and Newman, Inc. (1997)

Power plant construction generally occurs in phases, namely: 1) initial grading and excavation; 2) concrete pouring; 3) steel erection; 4) equipment installation; and 5) exterior finish and cleanup. Construction is expected to be completed within an 22-month period, and would likely occur over the course of single daytime shifts, although it is possible that extensions of the basic workday, or moderate amounts of evening or weekend work would occur. However, construction activities associated with higher increases in ambient noise levels would typically take place only during weekday daytime hours.

Construction Noise Levels

An acoustical model of construction operations and equipment was developed using SoundPLAN 6.5 to predict property line and off-site noise levels. Equivalent energy levels (L_{EQ}) were estimated for each of five major construction phases, including: 1) grading and excavation; 2) concrete pouring; 3) steel erection; 4) equipment installation; and 5) finishing and clean-up. Adjustments for hemispherical divergence, atmospheric absorption and ground effect were included. As shown in Table 4.1-8, L_{EQ} levels are predicted to range from 33 dBA to 46 dBA at nearby residential receivers. Note that noise levels presented in Table 4.1-8 are those expected outdoors and that a building or home would provide significant attenuation of these levels. Specifically, noise levels within homes and dwellings would be up to 27 dBA lower (with windows closed). Even in homes with open windows, indoor noise levels would be up to 17 dBA lower. [3]

[3] Environmental Protection Agency, Report No. EPA-550/9-74-004, March 1974.

TABLE 4.1-8
PREDICTED CONSTRUCTION NOISE LEVELS (dBA - L_{EQ})

Position	Construction Phase				
	Grading and Excavation	Concrete Pouring	Steel Erection	Equipment Installation	Finishing*
Receiver 01	46	42	46	41	36
Receiver 02	46	42	46	41	36
Receiver 03	46	42	46	41	36
Receiver 04	43	39	43	38	33
Property Line – North	70	66	70	65	60
Property Line – East	69	65	69	64	59
Property Line – South	73	69	73	68	63
Property Line - West	67	63	67	62	57

Note: Assumes mitigated steam-blows.

Any nighttime or weekend construction activities will likely be similar to the "finishing phase" of construction, which is typically ten decibels quieter than for other phases. Also, the size of a nighttime work force would be significantly smaller than during typical daytime, weekday hours, further reducing noise levels.

Plant Cleanout

At the conclusion of construction, but prior to commercial operation of Units 3 and 4, steam blows will be used to clear any accumulated dirt or debris from steam piping. This usually involves releasing high-pressure steam through the piping system and venting it to atmosphere. Steam blow sound levels are typically substantially louder than other construction activities, and may be disruptive to nearby residents. In order to minimize these short-term impacts, specially designed silencers will be installed on piping vents during plant clean-out, and nearby residents will be notified when this activity is set to begin.

4.1.1.5 Mitigation Measures

The proposed acoustical design of Units 3 and 4 will include silencers placed within the air intake ductwork of the combustion turbines to reduce high-frequency compressor and turbine blade noise levels. In addition, acoustical enclosures will reduce casing radiated noise from the combustion turbines, generators, gearing and other auxiliary support equipment. Turbine exhaust noise will be attenuated via the heat recovery steam generators (HRSGs) as well as by absorptive silencers placed either in the HRSG ductwork leading to the stacks or hung within the stacks themselves.

Moreover, the proposed expansion will take advantage of the existing acoustical barriers along the northern and western property boundaries. Additional acoustical barriers may be erected along the northern and southern property boundary to control property line noise levels (see conceptual barrier layout in Figure 4.1-4). Noise level measurements would be collected during performance testing (prior to commercial operation) and used to determine whether acoustical barriers along the property boundaries are necessary, and if so, the optimal height, length and placement of any barriers. Note that additional barriers are not required to achieve predicted levels at the residences.

Acoustical modeling indicates that based on this design, noise levels from the project are expected to fully comply with applicable limits at residential receivers and industrial properties. The precise details and extent of any noise control measures needed for the plant will be refined, if necessary, during the detailed engineering phase of the project, at a time when additional noise level data can be obtained from vendors, and when additional design details for Units 3 and 4 have been completed.

4.1.2 RISK OF FIRE OR EXPLOSION

The discussion of the risk of a fire or an explosion at the Grays Harbor Energy Center is organized in three parts: risk during construction, risk during operation, and mitigation of risk.

4.1.2.1 Risk During Construction

The risk of a fire or explosion during construction of Units 3 and 4 is considered to be extremely low. During construction, small quantities of flammable liquids and compressed gases will be stored and used. Liquids will include fuels, paints, and cleaning solvents. Compressed gases will include acetylene, oxygen, helium, hydrogen, and argon for welding. The potential hazards associated with use of these materials will be mitigated by following WAC 296-155 and Federal Occupational Safety and Health Administration (OSHA) Safety Standards listed in 29 CFR 1910, General Industry, and 29 CFR 1926, Construction Industry. The following is a list of applicable standards:

- OSHA training programs such as Hazard Communication 1910.1200, Confined Space Entry 1910.146, Lockout/Tagout 1910.147, and other OSHA mandated programs

- OSHA Standards such as Fire Prevention 1910.39, Traffic Control, Excavations 1926.650, Scaffolding 1926.451, Ladders 1926.1051, Use of Cranes and Crane inspections 1926.550, Storage of flammable and combustible liquids and gasses 1926.152, Fall Protection 1910.128, Welding and Burning 1910.252, 1910.255, Housekeeping 1926.25, Emergency Action Plans 1910.38, First Aid/Bloodborne Pathogens 1910.1030, Electrical Hazards 1910.332, Personal Protective Equipment. 1926.28, .100 -.106

4.1.2.2 Risk During Operation

Operation of the Grays Harbor Energy Center requires the use of two materials that can be explosive under certain conditions: natural gas and hydrogen gas. Natural gas will be the only fuel for the combustion turbines. The natural gas will be piped into the site; none will be stored on site. Hydrogen will be used as a coolant for the electrical generator for the combustion turbines and a maximum of approximately 110,000 cubic feet will be stored.

For many years, industry has stored and used natural gas, hydrogen, and fuel oil in large quantities with little history of explosions or fire. When explosions occurred, they resulted from equipment malfunctions or operator errors. During these incidents, flammable gases were released in an unsafe manner, either inside equipment or to the work area. The combination of flammable gases, ignition sources, and oxygen resulted in explosions. As a result of these incidents, codes, regulations, and consensus standards have been upgraded to reduce the likelihood of recurrences. All phases of construction and operation of Units 3 and 4 will be conducted in compliance with these codes and regulations, as applicable.

Aqueous ammonia will be used for injection into the SCR system for NO_x control and will be stored on site. However, aqueous ammonia is not considered a risk in terms of explosion potential or flammability, as it is composed of 70 percent water and will be stored separately from non-compatible materials in compliance with fire safety regulations.

4.1.2.3 Mitigation of Risk

The risk of an explosion at the Grays Harbor Energy Center will be mitigated by designing, constructing, and operating the facility as required in the latest versions of the applicable codes, regulations, and consensus standards.

As with the existing Grays Harbor Energy Center, Units 3 and 4 will be operated by qualified personnel using written procedures. Procedures provide clear instructions for safely conducting activities involved in the initial startup, normal operations, temporary operations, normal shutdowns, emergency shutdowns, and subsequent startups. The procedures for emergency shutdowns include the conditions under which emergency shutdowns are required, and the assignment of shutdown responsibilities to qualified operators to ensure that shutdowns are done in a safe and timely manner. Also covered in the procedures are the consequences of operational deviations and the steps required to correct or avoid the deviations.

Before being involved in operating the facility, employees will be presented with a facility plan, including a Health and Safety Plan, and will receive training regarding the operating procedures and other requirements of safe operation of the plant. In addition, employees will receive annual refresher training, which will include testing of their understanding of the procedures. Training and testing records will be maintained.

The existing hazardous materials emergency response program will continue to be used. Grays Harbor Energy emergency responders trained and equipped to the technician level will be available at all times when the project is in operation. The emergency responders will use a written emergency response plan developed for the Grays Harbor Energy Center and revised, if needed, to include the addition of Units 3 and 4.

4.1.3 RELEASES OR POTENTIAL RELEASES TO THE ENVIRONMENT

4.1.3.1 Handling, Storage, and Disposal of Hazardous Materials

No new hazardous materials will be used for the construction or operation of Units 3 and 4. Handling, storage, and disposal of toxic and hazardous materials used in construction and operation of the project will be in accordance with applicable state and federal regulations. The handling procedures for wastes produced by the operation of Units 3 and 4 will be similar to those currently approved for the Grays Harbor Energy Center and will not result in a threat to public health and safety. However, only minor amounts of hazardous wastes will be generated by Units 3 and 4, primarily small quantities of materials such as used paints, thinners, and solvents.

4.1.3.2 Hazardous Waste Management

Any dangerous wastes generated by the Grays Harbor Energy Center will be managed by project personnel to ensure compliance with the Washington Dangerous Waste Regulation (WAC 173-303). The dangerous wastes will be limited to solvents and paint wastes generated during maintenance activities. Grays Harbor Energy has been assigned generator identification number WAD 980188510. A comprehensive dangerous waste management program fulfilling all requirements of the regulation is in place for the Grays Harbor Energy Center. This includes waste designation, labeling, storage, handling and disposal procedures; record keeping; inspection; contingency planning; and management oversight elements. This program will apply to Units 3 and 4, and will include requirements for training of owner and contractor personnel in proper handling, storage, and disposal of hazardous materials.

4.1.3.3 Hazardous Substances

Title III of the Superfund Amendments and Reauthorization Act and OSHA's Hazard Communication Standard mandate communication of information to local agencies to assist in their response to emergency situations. Material safety data sheets (MSDS), which provide specified information on each toxic or hazardous material stored and used on site, will be maintained on file. A list of MSDS will be provided to local emergency response agencies, including the Elma Fire Department. The MSDS describe the potential health effects of each substance under different types of exposure and appropriate safety and treatment measures. The Certificate Holder will provide an annual inventory of the toxic and hazardous materials used on site (in accordance with Tier 2 reporting requirements).

4.1.3.4 Hazardous Substance Release

If during the operation of the facility any substance listed in 40 CFR 302 is released to the environment, the Certificate Holder will notify EFSEC, the National Response Center, the Environmental Protection Agency, and Ecology as required under Section 101(14) of the Comprehensive Environmental Response, Compensation and Liability Act. Grays Harbor Energy's response to any accidental release will be guided by its SPCC Plan, which will be updated if needed to include Units 3 and 4 (see Section 2.9, Spillage Prevention and Control, WAC 463-60-205), and any additional measures required by EFSEC or Ecology.

In addition, the state Dangerous Waste Regulations, as codified at WAC 173-303, enforce the federal Resource Conservation and Recovery Act in Washington state. The existing SCA for the Grays Harbor Energy Center stipulates waste management procedures in accordance with the state regulations and these will be followed for Units 3 and 4.

4.1.4 SAFETY STANDARDS COMPLIANCE

The contractor and its subcontractors will be required to comply with applicable local, state, and federal safety, health, and environmental regulations. The primary standards to be used in the design, construction and operation of Units 3 and 4 are the same as approved for the existing Grays Harbor Energy Center.

4.1.5 RADIATION LEVELS

The proposed addition of Units 3 and 4 is not expected to use or release any radioactive materials during operation. During construction, there will be a minor, controlled use of radiation. This will consist of X-rays of some plant equipment welds.

Minor controlled use of radiation during construction will be in accordance with state and federal standards and project-specific permit conditions covering these materials.

4.1.6 EMERGENCY PLANS

Grays Harbor Energy, the Certificate Holder, has prepared and implemented a series of emergency plans for the Grays Harbor Energy site, and the plans are applicable to the construction and operation of Units 3 and 4. These plans have been prepared to ensure public safety and environmental protection on and off the Grays Harbor Energy property in the event of a natural disaster or other major incident relating to or affecting the Grays Harbor Energy Center. The plans describe the emergency response procedures that are to be implemented during emergency situations. The plans were approved by EFSEC on November 1, 2005

SECTION 4.2 LAND AND SHORELINE USE (WAC 463-60-362)

This section addresses the land and shoreline use issues applicable to the proposed Units 3 and 4, including the following sections:

- Relationship to Existing Land Use, Land Use Plans, and Estimated Population (Section 4.2.1)
- Housing (Section 4.2.2)
- Light and Glare (Section 4.2.3)
- Aesthetics (Section 4.2.4)
- Recreation (Section 4.2.5)
- Historic and Cultural Preservation (Section 4.2.6)
- Agricultural Crops/Animals (Section 4.2.7)

4.2.1 RELATIONSHIP TO EXISTING LAND USE, LAND USE PLANS, AND ESTIMATED POPULATION

4.2.1.1 Existing Conditions

Land Uses

Units 3 and 4 will be located within the approved 22-acre Grays Harbor Energy Center site. Construction of the Grays Harbor Energy Center was completed in the second quarter of 2008 and it began commercial operation on April 25, 2008. The site is located in Grays Harbor County in western Washington. Adjacent development varies, generally characterized by office, industrial, rural, rural residential, and agricultural land uses. This section describes of existing land uses adjacent to the site and the plans and policies that guide development on this site, and discusses the impact of the project on these elements. Detailed discussion of the relationship of the project to estimated population can be found in Section 4.4, Socioeconomic Impacts, WAC 463-60-535.

Plant Site. The Grays Harbor Energy Center site is located near the town of Elma in Grays Harbor County, and is surrounded on all sides by the property boundary of the Satsop Development Park (Figure 2.1-1 in Section 2.1). The Satsop Development Park is owned by the Grays Harbor PDA. The approximately 22-acre site was previously developed for and used as a laydown area during construction of now-discontinued nuclear plants WNP-3 and WNP-5 located at the Satsop Development Park. Prior to the start of site work for the Grays Harbor Energy Center, most of the site was covered by a layer of graded gravel several feet deep and surrounded by a chainlike fence topped with barbed wire. The western portions of the site adjacent to Keys Road have been paved with asphalt.

Keys Road provides vehicular access to the site. This is a two-lane county road that runs along the western site perimeter in a generally north-south direction that connects with State Route (SR) 12 north of the proposed site. To the south of the site, the BPA maintains a transmission corridor as part of its Olympia-to-Aberdeen grid connection. Most of the other areas surrounding the site are forested. About a quarter mile southwest of the site, the Weyerhaeuser Timber Company manages an experimental forest that is approximately 50 acres in size. On the north side of this forest, about two-thirds of a mile west-southwest of the site, are about a dozen single-family houses (these appear as small black dots on Figure 2.1-1). Southeast of the site is the Fuller Creek preservation area. The discontinued nuclear power plant facilities (WNP-3 and WNP-5) lie beyond this area, approximately 1 mile south and southeast of the project site. Forested areas are located north of the site, beyond which the grade drops rapidly down toward the Chehalis River, which is approximately 0.5 mile from the project site.

Ten-Acre Construction Laydown and Access Area. The Satsop Development Park is the site of an unfinished and unfueled former nuclear power plant. Construction of the site began in 1977 by WPPSS and BPA, and was halted in 1983. Though construction ceased, a Wildlife Mitigation Agreement associated with the power plant project continued to be developed, and was approved in 1990. The Wildlife Mitigation Agreement imposed restrictions on activities throughout the Satsop Development Park and limited the developable area to what had already been disturbed, approximately 450 acres. The 10 acres proposed for construction laydown and access were originally included within the area set aside for wildlife mitigation; however, they have since been designated for intensive development in the Satsop Development Park's Master Plan.

The Satsop nuclear site was left unused for over a decade until the project was formally terminated in 1995. Subsequently, leaders of Grays Harbor County, the Port of Grays Harbor, Grays Harbor Public Utility District, and the Grays Harbor Council of Governments collaborated to evaluate the redevelopment potential of the site to bring jobs and provide an economic stimulus to Grays Harbor County. In 1999, the Washington State Legislature formed the Grays Harbor PDA and allocated seed capital to develop the site as a business and technology park to attract diverse technological and manufacturing companies. The Satsop Development Park is now a business and industrial park with industries ranging from data centers to energy production.

In October 2007, the Grays Harbor PDA published the Satsop Development Park Master Plan, which is intended to guide and direct the future infill and build-out of the site to realize its full potential. A number of State of Washington staff members participated in creation of the Master Plan, including Stephan A. Kalinowski of Washington Department of Fish and Wildlife and Rich Scrivner of Washington State DNR.

The Master Plan identifies seven planning areas. The Grays Harbor Energy Center site and the proposed 10-acre construction laydown and access area are located within Area 2: West Park (see Figure 3.1 in the Satsop Development Park Master Plan.). The Satsop Development Park Master Plan establishes two primary land use designations: developable and multi-use areas. Page 35 states, "*Developable areas are where development in the form of buildings, roads, parking, and other infrastructure will occur or already exists. Developed areas are generally those that have already been cleared and graded, and have infrastructure in place, or are immediately adjacent to existing development. Multiuse areas encompass a variety of non-development uses, including passive recreation, forest management, wildlife habitat, infrastructure corridors, and education and research. In some areas, habitat restoration or enhancement could be achieved in order to improve natural functions and conditions. Areas 1 and 2 are designated for intensive development and Areas 3 through 7 are designated as multi-use.*"

Area 2: West Park, the planning area in which the combined 32-acre site is located, is designated for intensive development, and not for wildlife habitat. The West Park Planning Area is further described on page 53 of the Master Plan: *"The West Park Planning Area is a key component of the Park's economic development goals. West Park is approximately 170 acres, much of which is currently undeveloped. It is a secondary 'gateway' into the Park, accessed from State Route 12 via Keys Road."*

The West Park area's direct access to the highway, separation from the Main Campus, and the character of existing uses make it most suitable for more intense industrial uses. Current tenants include Livingston Boats, Simpson Door Company, L&L Machinery Company, Northwest Pipeline, and Invenergy, which owns its 32-acre parcel where it houses a combustion turbine facility. The siting of this power plant creates a restriction on residential development within a 200-foot buffer. The BPA right-of-way cuts through the southern portion of the area. Due to its remote location within the park and heavy industrial uses, the West Park area will have restricted public access. It is estimated that West Park has capacity for 30,000 square feet of office and 690,000 square feet of light and heavy industrial at full-build-out.

Existing Plans and Policies

The plant site is located in unincorporated Grays Harbor County near the town of Elma and surrounded by the property boundary of the Satsop Development Park (Figure 2.1-1).

As described above, the continued use of the Grays Harbor Energy Center site and the use of the adjacent 10-acre site for construction access and laydown is consistent with the Satsop Development Park Master Plan.

The plant site is located in areas zoned as Industrial District 2, or I-2, under Grays Harbor County Comprehensive Zoning Ordinance No. 241 (Title 17). According to Grays Harbor Zoning Ordinance 17.52.010, *"The purpose and intent of the industrial district is to provide areas where industrial activities and uses involving the processing, fabrication and storage of products may be located. The district also allows such commercial uses that serve primarily the industrial district."* Uses permitted outright include industrial uses and industrial development facilities as defined by RCW 39.84.020 Part 6. Energy facilities are included within this definition and are permitted outright.

In passing the rezone at a Grays Harbor Planning Commission meeting on November 2, 1998, the Planning Commission found that the utilization of the infrastructure originally built for the Satsop Nuclear Plant and the reuse of existing sites for industrial purposes will promote job creation and economic diversification, which are expressed purposes of the Grays Harbor County Comprehensive Plan.

In connection with the application for the original Grays Harbor Energy Center, EFSEC found that the project was *"consistent with applicable land use laws and regulations"* (EFSEC Order No. 694 *as modified,* April 15, 1996). In 2002, the Council considered a propose for an expansion of the Satsop CT Project that was very similar to the current proposal for Units 3 and 4, and EFSEC found that the proposed project *"is consistent and in compliance with Grays Harbor County and regional land use plans and zoning ordinances"* (EFSEC Order No. 766, March 27, 2002).

4.2.1.2 Impacts

During construction of Units 3 and 4, adjacent land uses may be affected by noise, dust, and construction-related traffic. Mainly due to the nature of the construction activities, impacts near the project site are expected to be temporary and minor. Further discussion of these impacts and measures that will be taken to mitigate them can be found in Section 3.2.4 Dust ; Section 4.1.1 Noise, and Section 4.3 Traffic.

In terms of land use, the presence of Units 3 and 4 at the project site will be compatible with the existing Grays Harbor Energy Center plant and adjacent industrial structures and facilities. Nearby residents may perceive the expanded plant as an intensified land use. However, this perception would be lessened as views into the project site become increasingly screened by maturing vegetation along Keys Road (see Section 4.2.4).

4.2.2 HOUSING

The existing housing stock and potential impacts are discussed in Section 4.4, Socioeconomic Impacts, WAC 463-60-535.

4.2.3 LIGHT AND GLARE

4.2.3.1 Existing Conditions

Units 3 and 4 would be added to the existing Grays Harbor Energy Center. The Grays Harbor Energy Center plant is illuminated at night for facility operations under normal conditions and for means of egress under emergency conditions. Illumination levels were designed in accordance with the Illuminating Engineering Society standards recommended by the following guidance:

- ANSI/IES RP-7, 1983, Industrial Lighting
- ANSI/EIS RP-8, 1983, Roadway Lighting
- Federal Aviation Administration guidance
- OSHA guidance

In addition, existing high-mast lights in the adjacent industrial yards provide wide-area illumination. Other lights in the immediate area include entry and yard lights around a small group of residences located within approximately two-thirds of a mile of the project site. Evergreen trees screen the project site on the east. Additional forested areas are located north of Keys Road, and these trees as well as a 25-foot-high wall with a vegetated berm along Keys Road screen lights originating from the Grays Harbor Energy Center, the Satsop Development Park and other adjacent land uses.

4.2.3.2 Impacts

The construction and operation of Units 3 and 4 would not significantly increase the existing light and glare conditions. The additional two units would be illuminated at the same times and illumination levels as the existing Grays Harbor Energy Center plant. Table 4.2-1 summarizes the illumination levels expected for Units 3 and 4.

Lighting would be provided for the purposes of general operator access and safety under regular operating conditions. Precise and detailed placement of lighting fixtures has not yet been determined, but light poles will likely be standard street light height, in the range of 20 to 50 feet. Outside lighting around the exterior of buildings and ancillary equipment would likely be attached to walls.

TABLE 4.2-1
EXPECTED ILLUMINATION LEVELS FOR EXTERIOR FACILITY AREAS

Exterior Location	Maintained Foot-Candles
Boiler platforms	10
Emergency lighting	3
Hydrogen manifold area	20
Electrical switchyard	5
Exterior walkways and platforms	2
Roadway	1
Security fence	0.5
Outdoor areas containing equipment that requires periodic inspection	5
Cooling tower	5

Source: N. DeRidder, personal communication

Spot lighting (up to 20 foot-candles) would be provided for localized area illumination for specific work activities such as the hydrogen manifold area. This lighting would be of higher intensity than wide-area lighting, but will be limited to specific areas and occasional usage. Emergency lighting would be provided for personnel egress and continuance of critical activities during emergency conditions. These instances are anticipated to be infrequent.

During construction, there would be some lighting associated with construction machinery. During operation, the most visible points of illumination would be small, high-intensity anti-collision lights on the emission stacks to warn aircraft. These lights are intermittent and would be similar to warning lights present on the nearby WNP-3 and WNP-5 cooling towers and on the existing cooling towers for the Grays Harbor Energy Center.

Light and glare impacts upon nearby residents and travelers along Keys Road are expected to be insignificant. Prior to the start of construction of the Grays Harbor Energy Center, there were existing high-mast lights providing wide-area illumination of the industrial yards. Local residents are already used to this local light source and the separation distance of approximately 3,375 feet provides a buffer zone for light falloff. The existing 25-foot-high wall and vegetated berm located along Keys Road will reduce the light from Units 3 and 4. Vegetation located on the berm and scattered existing vegetation between the project site and residences would screen most of the lights. Additional screening is provided by high trees located along the residential road since the residences are set back an estimated 50 to 75 feet.

4.2.3.3 Mitigation Measures

In specific locations where glare or light spillover could impact Keys Road or be obtrusive to nearby residences, lighting angles could be adjusted to minimize glare impacts, or supplemental light shields/vegetation could be used for extra screening.

4.2.4 AESTHETICS

4.2.4.1 Assessment Methodology

This section describes existing visual conditions of the proposed project setting. The visual inventory study consisted of the following:

- Setting criteria for rating levels of visual quality and viewer sensitivity
- Assessing existing visual quality levels
- Identifying viewer types, estimating their view of the facility (general visibility and distance range), and their visual sensitivity
- Selecting key representative viewpoints

Regional topography and site context information were reviewed using US Geological Survey topographic maps. Detailed topography and layout for the project site were analyzed by reviewing project plans provided by the Certificate Holder and its engineering and design contractor. Field work was conducted by driving and hiking the area to qualitatively determine general visibility of the project site from residences, major roads, and other potentially sensitive viewpoints. Based on visibility, representative viewpoints were photodocumented and two key viewpoints were selected for visual simulation (Figure 4.2-1).

Assessment methods were based on a combination of visual assessment techniques that characterize visual impact in terms of changes in visual quality, character, and viewer sensitivity. Visual quality levels were estimated for both regional and immediate project area settings. The regional landscape setting is defined as those areas north of the Chehalis River, typically at a distance of 1 mile or greater. Levels of visual quality and viewer sensitivity were qualitatively estimated based upon general criteria that establish ratings of "high," "moderate," or "low."

Levels of visual quality consist of three primary components: *vividness*, the memorability of the landscape resulting from distinctive landmark features or visual patterns; *intactness*, the visual integrity between natural and modified landscape components and the absence of encroaching disturbances; and *unity*, the visual coherence, composition, and harmony of landscape elements. Visual quality was evaluated using the following general criteria:

- ***Low –*** Landscape is common to the region and exhibits few, if any, memorable features or patterns which provide visual diversity. A prevalence of encroaching human elements or landscape modifications exist that do not compatibly blend with the natural surroundings (low visual intactness and unity). Human alterations (such as roads and power lines) exhibit low maintenance or siting sensitivity (such as grading and alignment).

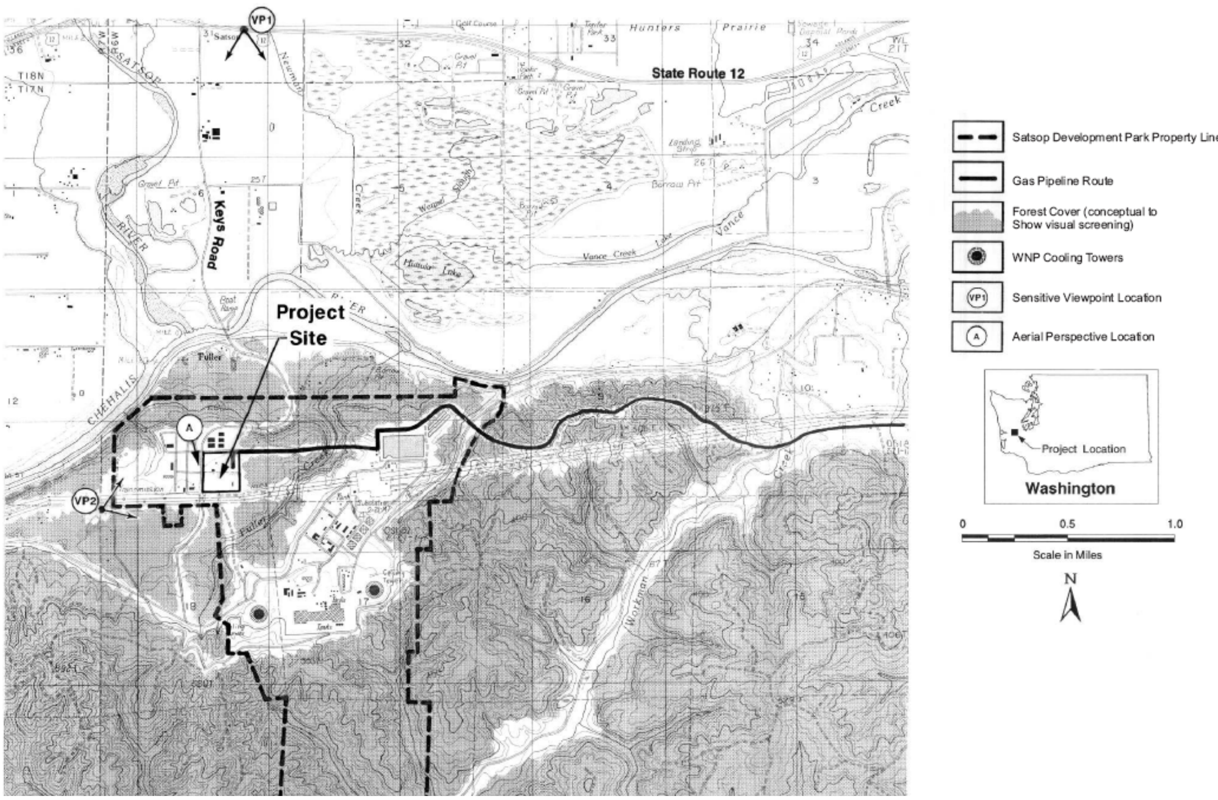


Figure 4.2-1
Sensitive Viewpoint Locations Map

- ***Moderate* –** Landscape exhibits reasonably attractive natural and human-made features/ patterns, although they are not visually distinctive or unusual within the region. The landscape integrity of the area provides some positive visual experiences such as natural open space with some existing disturbance (farm fields, etc.), or well-maintained industrial parks and residential areas.

- ***High* –** Landscape exhibits distinctive and memorable visual features (such as landforms and rock outcrops) and patterns (vegetation/open space) which are largely undisturbed—usually a rural or open space setting. Development or visual disturbances, if present, are exceptionally well-planned to integrate with the natural landscape materials and character.

Viewer sensitivity depends on viewer types and exposure (number of viewers and view frequency), view orientation and duration, and viewer awareness and sensitivity to visual changes. Levels of viewer sensitivity were evaluated using the following criteria:

- ***Low* –** Viewer types in the project vicinity representing low visual sensitivity include agricultural and power plant workers. Compared with other viewer types, the number of viewers is generally considered small, and the duration of view is short. Viewer activities typically limit awareness and sensitivity to the visual setting immediately outside the workplace, which are often screened by vegetation or adjacent buildings.

- ***Moderate* –** Viewer types representing moderate visual sensitivity consist of highway and local travelers. The number of viewers varies depending on location; however, in the vicinity of the proposed plant, viewer numbers tend to be moderately large since they include travelers using SR 12 and other roads throughout the Chehalis River Valley. Viewer awareness and sensitivity also are considered moderate because destination travelers often have a focused orientation.

- ***High* –** Residential and recreational viewers and those congregating in public gathering places (such as churches and schools) are considered to have comparatively high visual sensitivity. The visual setting may in part contribute to specific building orientation or the enjoyment of the experience. Views may be of long duration and high frequency.

4.2.4.2 Existing Conditions

Visual Quality

Regional Setting. The Grays Harbor Energy Center site is within the property boundaries of the Satsop Development Park, which includes the cooling towers remaining from discontinued nuclear power projects WNP-3 and WNP-5. The Satsop Development Park is located in hilly terrain on the south side of the Chehalis River Valley. The two 496-foot-high cooling towers, associated with the nuclear facility, are dominating visual elements within the existing landscape.

The Chehalis River Valley is bounded by tree-covered hills rising approximately 540 feet from the elevation of the valley floor and is dissected by secondary water courses, including the

Satsop River, Fuller Creek, Newman Creek, and Vance Creek. Agriculture is the primary activity in the valley, and the landscape is a patchwork of fields whose textures and colors change with the season. Farm buildings, surrounded by groupings of trees, are located throughout the valley. Other elements in the valley that contribute to the visual character of the region include a golf course, trailer park, and gravel pits.

Overall visual quality of the regional landscape setting is classified as "moderate." The regional landscape exhibits moderate vividness because the natural and agricultural features, which are reasonably attractive, are not visually distinctive or unusual within the region. Visual intactness is also moderate because agricultural activities are visually compatible with the colors, textures, and patterns of the river valley, but other elements such as roads, farm buildings, and the cooling towers are not visually integrated with the surrounding landscape. Many farm buildings, for example, are light colored and have reflective metal roofs. Regional visual unity is rated moderate to high. Most scene elements seem to complement a rural/agricultural setting. With the exception of the cooling towers, constructed roads and utility corridors blend with the landform or are not visible.

Plant Site. From SR 12, the site is accessed by traveling south on Keys Road, which passes agricultural fields and then crosses the Chehalis River. The road then ascends a wooded hillside and emerges into a clearing on both sites of Keys Road that was formerly used as an equipment laydown area during construction of WNP-3 and WNP-5. The portion of the former laydown area located east of Keys Road is now occupied by the existing Grays Harbor Energy Center.

Visually, this area can be characterized as industrial. The existing Grays Harbor Energy Centergives the site an industrial appearance with block building forms ranging from 20 to 64 feet in height. Ancillary elements include enclosed combustion turbines and steam turbines, liquid storage tanks, electrical switchyards, two 48- to 52-foot-high cooling towers, fencing, two heat recovery steam generators, and two 180-foot-high emission stacks. Figure 2.3-1 in Section 2 shows an isometric view of the existing Grays Harbor Energy Center without the surrounding existing vegetation or topographic features.

During certain seasons or weather conditions, water vapor and combustion products are visible from the cooling towers and emission stack of the Grays Harbor Energy Center. In addition, transmission poles extending along the northern portion of the existing BPA Olympia-to-Aberdeen right-of-way were replaced as part of the Grays Harbor Energy Center construction. The former wooden poles in the right-of-way were replaced with steel towers similar to the two rows of steel towers currently in the right-of-way. These towers carry existing transmission lines from the plant to the Satsop substation located approximately 4,000 feet east of the project.

A composite visual quality rating of "low" for the immediate project area is a result of low ratings of vividness, intactness, and unity. Although the hilly terrain of the area provides some visual variety, the flat landscape of the project site is fairly monotonous. There are no long-range penetrating views. Surrounded by a uniform stand of trees around the periphery of the cleared laydown area, there is limited color, texture, or pattern variety. Visual intactness is low because elements of the existing storage yard are not visually integrated with the landscape. No screening is provided, and visually contrasting materials consist of asphalt, cinders, and steel.

Visual unity is also low because layout configuration of the storage yards is rectilinear (contrasts with native forms), piles of stored materials are scattered across the site, and the transmission line corridor passes through a linear swath of cleared vegetation.

Viewer Types and Sensitivity

Primary viewer types in the vicinity of the Grays Harbor Energy Center site are residents, travelers along SR 12 and local roads, agricultural workers, and workers at businesses located in the Satsop Development Park..

The nearest communities are Montesano, Satsop, and Elma, which are located along SR 12. Residents along the edges of these communities generally have open views across the Chehalis River Valley. These views are bounded by tree-covered hillsides seen in the distance. The WNP-3 and WNP-5 cooling towers and the upper portion of the discontinued nuclear facility building are widely visible. Community residents represent the highest concentration of viewers in the region, and would be potentially sensitive to visual changes. Typical viewing range to the plant site from the closest community of Satsop would be approximately 2 miles. Similar viewing conditions would exist for scattered farmstead residences throughout the valley between SR 12 and the Chehalis River where the minimum viewing distance would be approximately 1 mile.

The closest and most sensitive residential views are in the vicinity of several houses located on a rural road paralleling the BPA transmission line right-of-way (the houses appear as small black dots on Figure 2.1-1). These viewers are located approximately 2,300 feet from the project area. Existing views from this location consist of the existing Grays Harbor Energy Center plant, electrical equipment, including transmission lines and towers, and laydown yards containing concrete forms, steel reinforcing bars, and other remnants of WNP-3 construction. The number of viewers at this location is small, estimated to be 8 to 15. But because the plant site will be relatively close, the residential viewers could be sensitive to visual changes.

SR 12 is the main east-west travel route through the Chehalis River Valley. The attention of travelers is drawn to the open agricultural fields south of the highway. Views are open for approximately 2 miles and are terminated by tree-covered hillsides. Again, the existing cooling towers and the nuclear facilities are dominant visual elements. Visual sensitivity for travelers along SR 12 and local streets within nearby communities is considered “moderate.”

Views from local roads within the immediate plant site area are generally short-range and are typically blocked by vegetation and topography. A few elevated dirt roads located in the hills south of the site have open, overlooking views of the discontinued Satsop nuclear facilities, and the Chehalis River Valley can be seen in the distance. Since these roads are not considered destinations for scenic driving and traffic volumes are estimated to be low, overall visual sensitivity is considered “moderate” to “low.”

The project site is located approximately 2.5 miles south of the intersection of SR 12 and Keys Road. Keys Road continues to the south, and passes immediately adjacent to west side of the plant site. The primary travelers along this section of Keys Road are power plant employees and a few local residents. In general, local residents who travel this road are expected to be more sensitive to visual impacts than industrial workers, but the overall visual sensitivity of travelers using Keys Road is considered "low" because of the short view duration and the presence of existing industrial yards, which has desensitized viewers over time. The higher visual sensitivity of residential travelers, compared to other types of travelers, is reflected in the higher sensitivity rating already given to residential viewers.

Agricultural workers throughout the Chehalis River Valley have views comparable to those of travelers along SR 12. Workers at the Satsop Development Park have short-range views that are predominately blocked by dense evergreen trees and hilly topography around the facility. The visual sensitivity of agricultural and power plant workers will generally be low because attention is focused on work activities with limited awareness of peripheral visual conditions.

Visual Changes Introduced by the Proposed Project

Prior to construction of the Grays Harbor Energy Center, materials stored on the plant site were relocated and the foundations of former buildings were removed. The site was regraded. A 25-foot-high noise wall with a 12-foot high vegetated berm has been constructed to screen views along Keys Road. This berm is vegetated with native shrubs, grasses, and other appropriate vegetation in a random arrangement to simulate native patterns.

The purpose of this berm is primarily to provide partial visual screening for nearby residents and travelers along Keys Road. The relationship of the berm to the existing Grays Harbor Energy Center and proposed Units 3 and 4 is shown in Figure 2.3-2**.**

Project Visibility

A field visit was conducted to qualitatively note or photograph potential views of the project site from a variety of surrounding land use areas, located both near (less than 1/8-mile) and distant (up to 4 miles). These represent residential, traveler, and industrial/agricultural viewer types. Since topography limits most views from the south and east, field work was concentrated to the north and west of the project site. Areas checked included:

- Peripheral edge of the community of Satsop
- SR 12 corridor (east/west)
- Keys Road corridor (north/south)
- Agricultural fields in the Chehalis River Valley
- Elevated dirt roads in the hills south of the project site near WNP-3
- Area immediately surrounding the project site within a 0.5-mile radius

Other surrounding areas were visited, but views were blocked either by topography or vegetation.

Based on the number of viewers, viewer types/sensitivities, and viewing distance, two viewpoints were selected from the general areas having project visibility. These two viewpoints, shown on Figure 4.2-1, were used to prepare two photo simulations depicting proposed conditions of adding Units 3 and 4. Viewpoint 1 (Figure 4.2-2) looks south from SR 12 approximately 0.25 mile east of the Keys Road junction. It represents the mid-to-distant viewing range (1 to 2 miles) seen by the largest number of viewers including SR 12 travelers, residents of nearby communities, and agricultural workers.

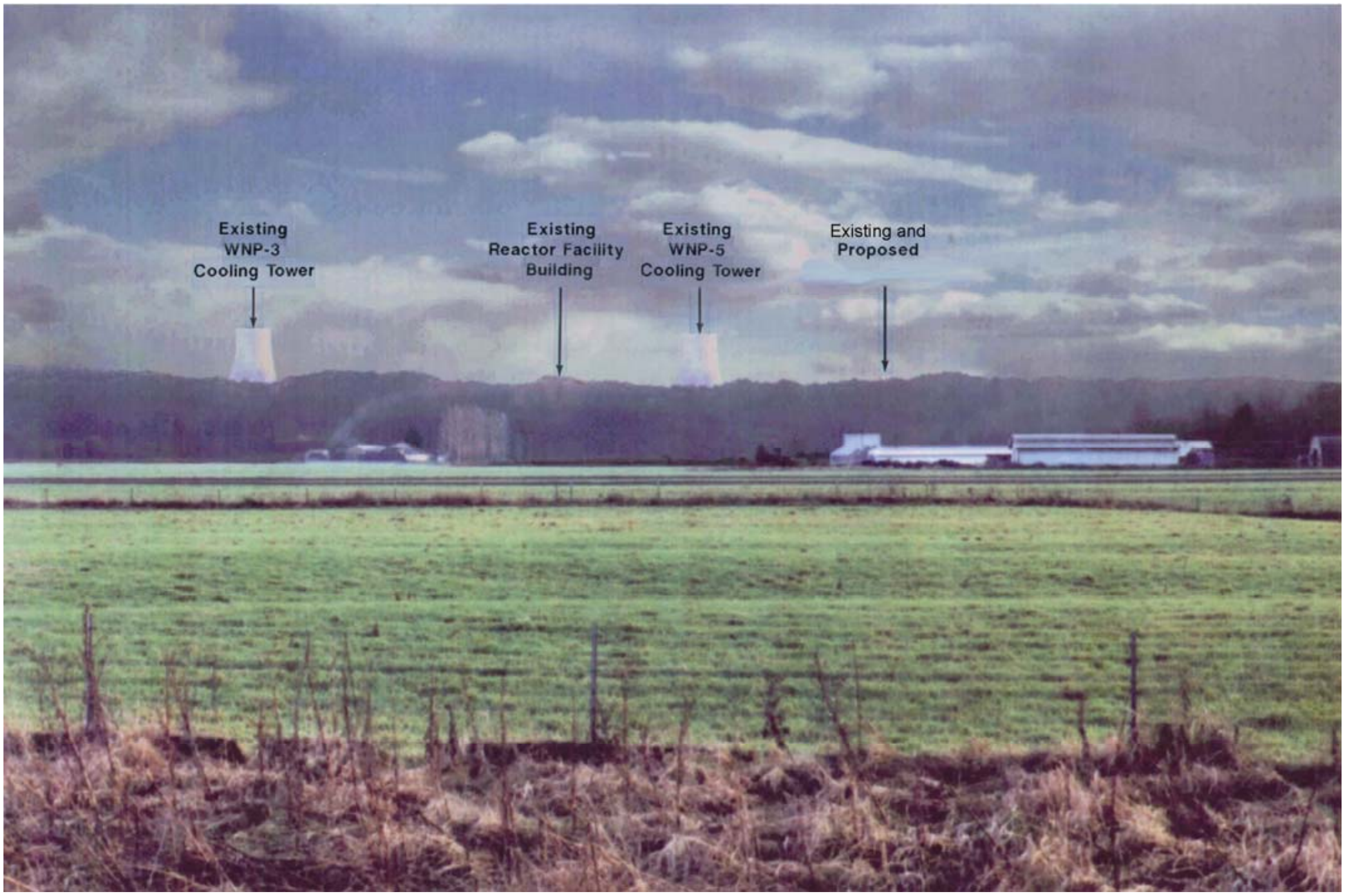


Figure 4.2-2
Simulated View of the Proposed Units 3 and 4 Stacks

Figure 4.2-2 shows the existing nuclear facility buildings protruding above the treeline. The cooling towers for WNP-3 and WNP-5 dominate the existing view. The emission stacks of the proposed Units 3 and 4, if visible above the treeline, will be located west of the existing cooling towers. Based on available project and topographic data, the tops of the Unit 3 and 4 stacks, like the Unit 1 and 2 stacks, will likely be at or just below the treeline elevations from this viewpoint. Since visibility versus no visibility is close to the threshold of model accuracy based on available data, the tops of the stacks protruding above the treeline are shown as a conservative graphic depiction.

If flashing airplane warning lights are required on the emission stacks, the lights also may be visible at night, as are the lights on the existing WNP-3 and 5 cooling towers. Generally, the project buildings and ancillary facilities would not be visible from this viewpoint because the site is screened by topography and vegetation.

The second viewpoint (VP2 on Figure 4.2-1) was chosen because the view is sensitive due to close residences that are within about 2/3 of a mile of the proposed additional two units. This view shows the existing power transmission lines as well as portions of the proposed facility, including the emission stacks (Figure 4.2-3). The vegetated berms adjacent to and west of the plants partially block the view towards the facility, as well as the view of some of the existing buildings on other portions of the laydown area.

Figure 4.2-3
Simulated View of the Proposed Grays Harbor Energy Center (Viewpoint 2)

The vegetated screening berms along Keys Road will block views of the lower portion of the facility, but the tops of the turbine buildings, cooling towers, emission stacks, and electrical switchyards will be visible. The most visible portion of the plant from this location will be the electrical switchyards, which are the closest elements. Visibility will decrease somewhat as screening vegetation reaches maturity. After vegetation is established, views of the project site area may be improved compared to current conditions. Again, the facility's higher components will protrude above the screen.

In addition to the views selected for visual simulation representing travelers and residents who have higher visual sensitivity, views were selected for less sensitive viewer types, including agricultural and industrial workers.

General visibility of the enlarged Grays Harbor Energy Center by agricultural workers in the Chehalis River Valley will be similar to that of travelers on SR 12 represented by Viewpoint 1. As from most other viewpoints, it is possible that agricultural workers could see a small portion of the emission stacks protruding above the treeline in the distance.

Satsop Development Park workers will have views of the facility when using Keys Road, but once inside the Development Park, views of the facility will be blocked by intervening trees.

4.2.4.3 Impacts

The assessment of impacts of the addition of Units 3 and 4 on visual quality included consideration of contrasts between current and proposed conditions for high or moderate levels of visual quality and high or moderate levels of viewer sensitivity as shown in Table 4.2-2. Following these guidelines, high sensitivity and a moderate change in visual quality could be considered potentially significant. Where sensitivity and visual change were both judged to be moderate, impacts are not considered potentially significant.

TABLE 4.2-2
VISUAL IMPACT ASSESSMENT MATRIX

Sensitivity Level	Level of Change in Visual Quality		
	High	Moderate	Low
High	PS	PS	A/N
Moderate	PS	A/N	N
Low	A/N	N	N

A/N – minor adverse, not significant
N – not significant
PS – adverse, potentially significant (without mitigation)

Visual impacts of Units 3 and 4 construction activities would be "not significant" regarding the overall landscape setting. Viewers throughout the Chehalis River Valley would not observe construction of the buildings or ancillary facilities, with the possible exception of a small portion of the emission stacks. For nearby residents and travelers on Keys Road passing adjacent to the site, construction of Units 3 and 4 would be seen less and less as the planting on the berm matures and screens views.

The wall and vegetated berm located adjacent to the project site along Keys Road would provide some degree of visual screening of construction activities. Equipment enclosure buildings and exterior tanks would be painted earth-tone beige and gray to reduce contrasts. The emission stacks would be painted to blend with the sky as seen from distant viewpoints.

Visual impacts of the operation of Units 3 and 4 in combination with Units 1 and 2 upon the existing regional landscape (Figure 4.2-3) are expected to be "minor adverse, not significant." Even though project buildings and ancillary facilities would not be seen, a small portion of the emission stacks may be visible from some viewpoints in the Chehalis River Valley. The cooling towers, juxtaposed against the horizontal profile of the background hills, are objects of attention for viewers looking across the open plain of the Chehalis River Valley. If visible, the presence of small portions of the emission stacks will be an additional, but minor, element to the west of the existing and taller cooling towers of WNP-3 and WNP-5. Depending on the time of year and weather conditions, attention to the stacks could be more pronounced when a vapor plume is present.

The impact to local residents adjacent to the site (Figure 4.2-3) is expected to be "minor adverse, not significant" due to overall visual compatibility of the project with the existing conditions. Even though the emission stacks and the higher plant structures would be visible, the proposed Units 3 and 4 would be screened by the 25-foot-high wall with vegetated berm along Keys Road. The buildings enclosing the turbine equipment would also reduce visual impacts. The screening berm is primarily intended to reduce the visual impacts to nearby residents, and would reduce the visual impacts for travelers using Keys Road, even though the visual sensitivity for travelers is comparatively lower than other viewer types.

4.2.4.4 Mitigation Measures

Equipment enclosure buildings and exterior tanks would be painted earth-tone beige and gray to reduce contrasts. The emission stacks would be painted to blend with the sky as seen from distant viewpoints.

4.2.5 RECREATION

The addition of Units 3 and 4 to the existing Grays Harbor Energy Center would be entirely within the previously-studied project vicinity. No recreational activities exist on the 10-acre construction laydown and access area and conversion from forest and pasture land would have no recreation impacts. During construction, there may be temporary indirect impacts due to the possible the use of recreational facilities by construction workers during the 22-month construction period.

No mitigation measures are required.

4.2.6 HISTORIC AND CULTURAL PRESERVATION

Previous studies for historic and cultural resources were performed for both the existing 22-acre site and the surrounding area, including the 10-acre site proposed for construction laydown and access. No historic or cultural resources were found. The addition of Units 3 and 4 to the existing Grays Harbor Energy Center would be entirely within the previously disturbed area. The 10-acre construction laydown and access site is within the studied project vicinity; as a result, the addition of Units 3 and 4 would have no anticipated historic and cultural preservation impacts.

No mitigation measures are required.

4.2.7 AGRICULTURAL CROPS/ANIMALS

The 10-acre site proposed for construction laydown and access includes approximately 5 acres of forest and 5 acres of grassland/agriculture that is mowed every year. The loss of the 5 acres of grassland is considered a minor impact.

No mitigation measures are required.

SECTION 4.3 TRANSPORTATION (WAC 463-60-372)

This section presents information on existing traffic conditions and impacts related to transportation, including the following sections:

- Transportation Systems and Vehicular Traffic (Section 4.3.1)
- Waterborne, Rail, and Air Traffic (Section 4.3.2)
- Parking (Section 4.3.3)
- Movement/Circulation of People or Goods (Section 4.3.4)
- Hazards (Section 4.3.5)
- Conclusions and Recommendations (Section 4.3.6)

4.3.1 TRANSPORTATION SYSTEMS AND VEHICULAR TRAFFIC

This section identifies existing transportation facilities and traffic volumes in the vicinity of the proposed project and describes the potential traffic impacts due to construction and operation of the Units 3 and 4, in conjunction with the operations of Units 1 and 2.

4.3.1.1 Existing Conditions

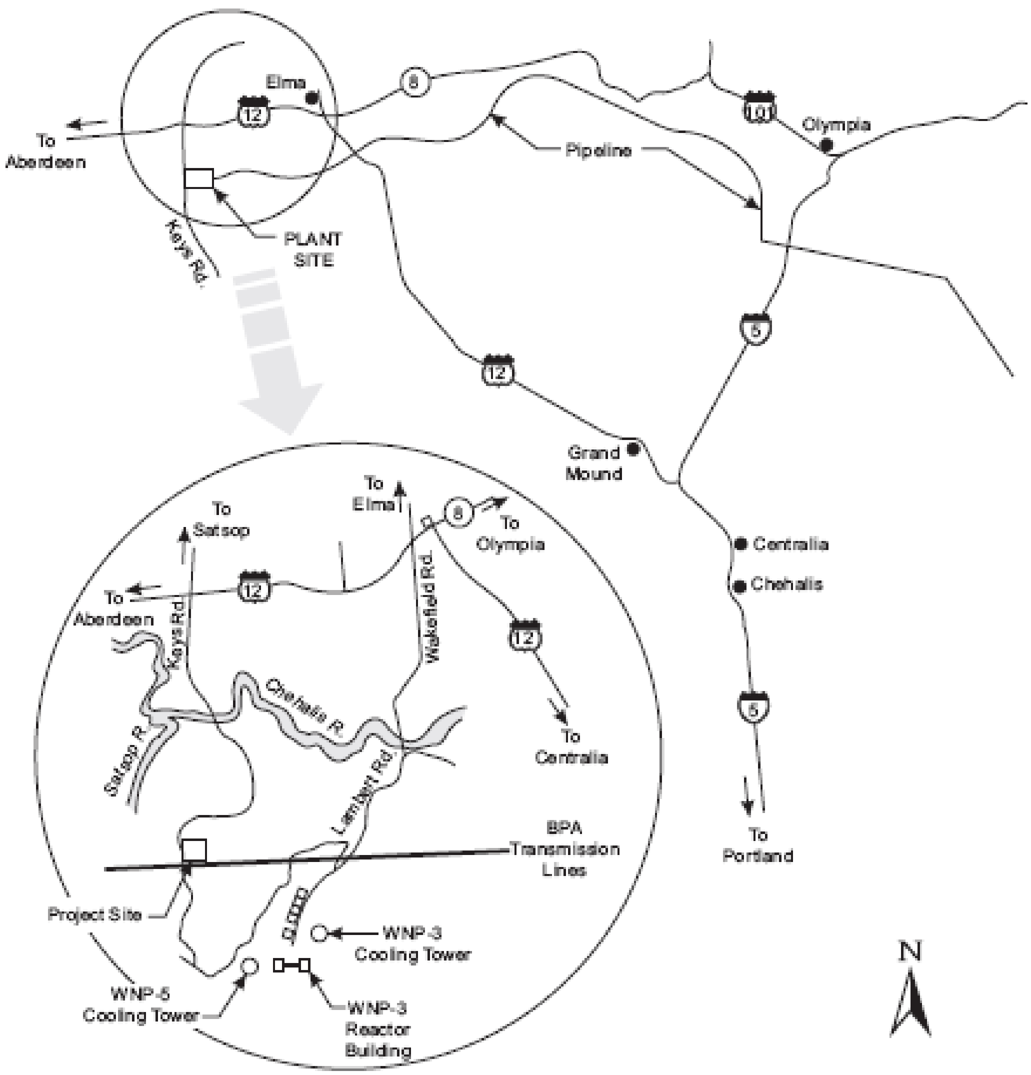
Street Highway System

Figure 4.3-1 shows the major roadways in the area. SR 12 is the predominant highway serving the plant site. SR 12 is a four-lane divided highway providing east-west access that extends from Aberdeen on the west to its intersection with SR 8 near Elma, then southeasterly to connect with Interstate 5 (I-5) north of Centralia. SR 8 continues east from Elma until it becomes US Highway 101 and connects to I-5. South of SR 8, SR 12 continues as a two-lane highway with shoulders of varying widths. The posted speed limit on SR 12 is 60 mph in the Elma to Montesano area. SR 12 at the intersection with Keys Road provides dedicated left and right turn lanes in the eastbound direction, and a dedicated left turn lane in the westbound direction.

Keys Road is a two-lane minor collector county arterial providing direct connection to the plant site and proposed project site. Keys Road is 24 feet in width with shoulders of varying widths (paved or gravel) and is stop sign controlled (two-way on Keys Road) at its intersection with SR 12. Keys Road at the intersection with SR 12 provides a dedicated right turn lane in the northbound direction, and a flared approach for right-turning southbound vehicles.

Access to the site is provided directly from Keys Road by an access driveway constructed within the site boundaries as part of the Grays Harbor Energy Center. The asphalt surface of Keys Road is in good condition, and the posted speed limit is 35 mph. The proposed plant site is located approximately 2.5 miles south of SR 12 along Keys Road.

Figure 4.3-1
Primary Roadways in the Project Area



The Wakefield Road corridor provides access to/from the project site from the east. Wakefield Road connects SR 12 to Keys Road via Lambert Road and is rated for heavy vehicles. Wakefield/Lambert Road is two lanes and the speed limit is 45 mph.

Review of existing traffic volumes at the intersection of SR 12 and Keys Road indicates that approximately 94 percent of the total entering traffic on SR 12 remains on SR 12, four percent exits to northbound Keys Road, and two percent exits to southbound Keys Road. Traffic on Keys Road approaching SR 12 distributes evenly to the east and west from either the north or south approaches.

Existing Traffic Volumes

Traffic volumes for the primary roadways in the project area for 2006 were obtained from the Washington State Department of Transportation *2006 Annual Traffic Report* (WSDOT 2006) and are presented on Figure 4.3-2. Forecasted 2008 volumes are based on historic average growth rates of approximately two percent per year between 1996 and 2006. Estimated 2008 pm peak traffic volumes for the intersection of SR 12 and Keys Road are presented in Figure 4.3-3. Traffic distributions were obtained from previous counts. Estimated 2008 volumes at this intersection are based on historic average growth rates of approximately one percent per year between 1993 and 2006 on SR 12 west of the interchange with SR 8.

Existing Levels of Service

The greatest delay to motorists in the project vicinity occurs during the pm peak hour. Delay for motorists at intersections is determined through calculation of level of service (LOS). Traffic operations at SR 12 and Keys Road were analyzed using *Highway Capacity Software Plus* (HCS+). HCS+ methodologies are based on the *Highway Capacity Manual* (TRB 2000). Level of service as defined in the *Highway Capacity Manual* is broken into several categories using a letter scale from A to F. LOS A represents little or no delay, whereas LOS F represents extreme delay. LOS E represents "capacity conditions" and LOS C or D represents the threshold for rural highway operations.

The LOS for unsignalized intersections is determined by the control delay experienced per vehicle. Control delay is defined as only that delay that is attributed to control measures such as traffic signals or stop signs. Table 4.3-1 presents LOS criteria for two-way stop controlled intersections as defined in the *Highway Capacity Manual*.

Using HCS+, LOS was determined for operations at the intersection of SR 12 and Keys Road for estimated 2008 traffic volumes (Table 4.3-2). All movements on SR 12 and the northbound right turn on Keys Road operate at LOS B or better.

2008 traffic volumes during the pm peak hour at the intersection of SR 12 and Keys Road were already at or were approaching the operational threshold for LOS E on the northbound and southbound approaches to SR 12 on Keys Road.

The overall northbound approach is just above the minimum control delay operationally for LOS D, with approximately 29 seconds of control delay per vehicle. The northbound left turn is near the maximum control delay, operating at LOS E with approximately 47 seconds of control delay per vehicle.

The southbound approach on Keys Road operates at LOS D with approximately 34 seconds of control delay per vehicle.

Figure 4.3-2 Existing Traffic Volumes

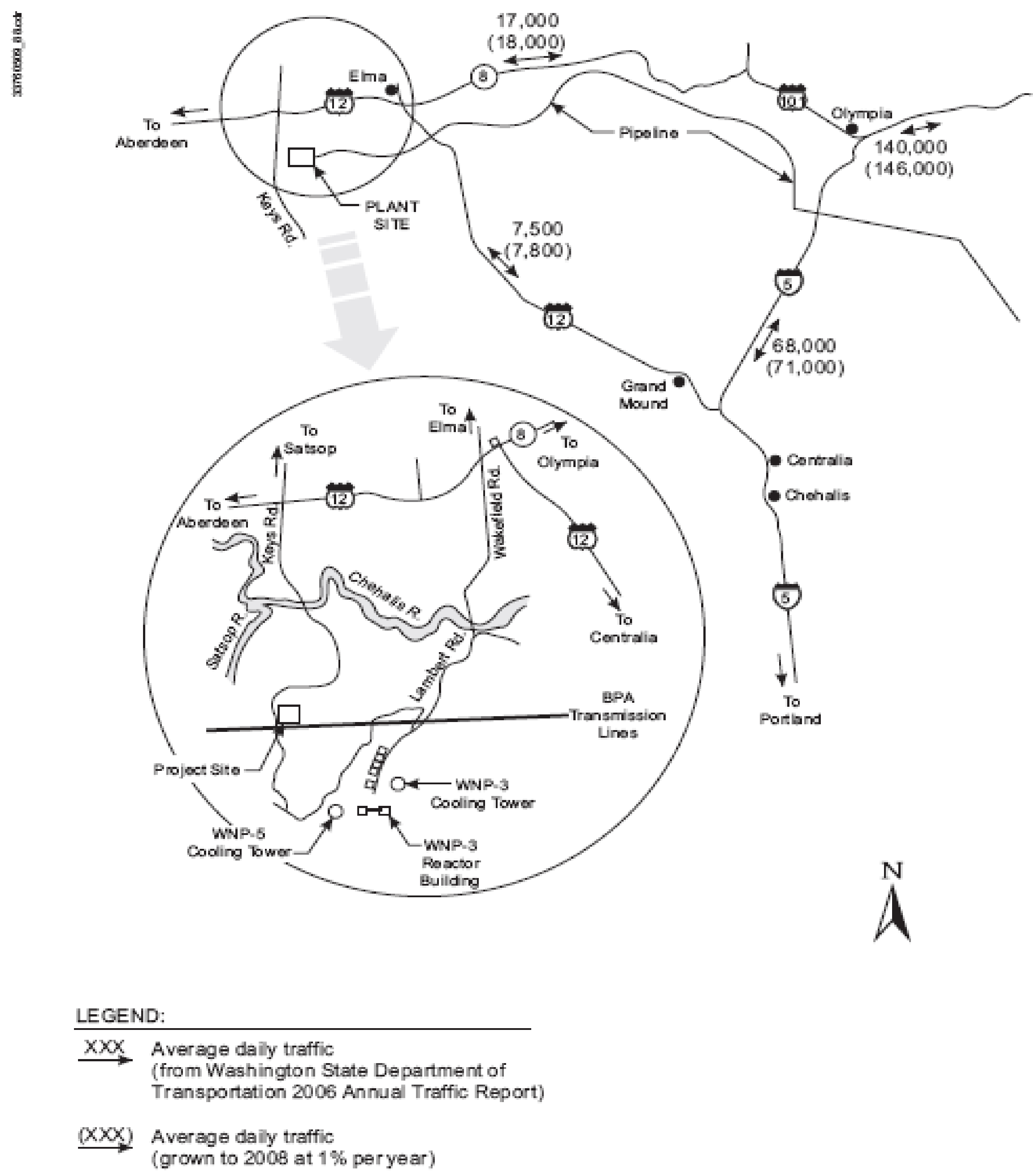
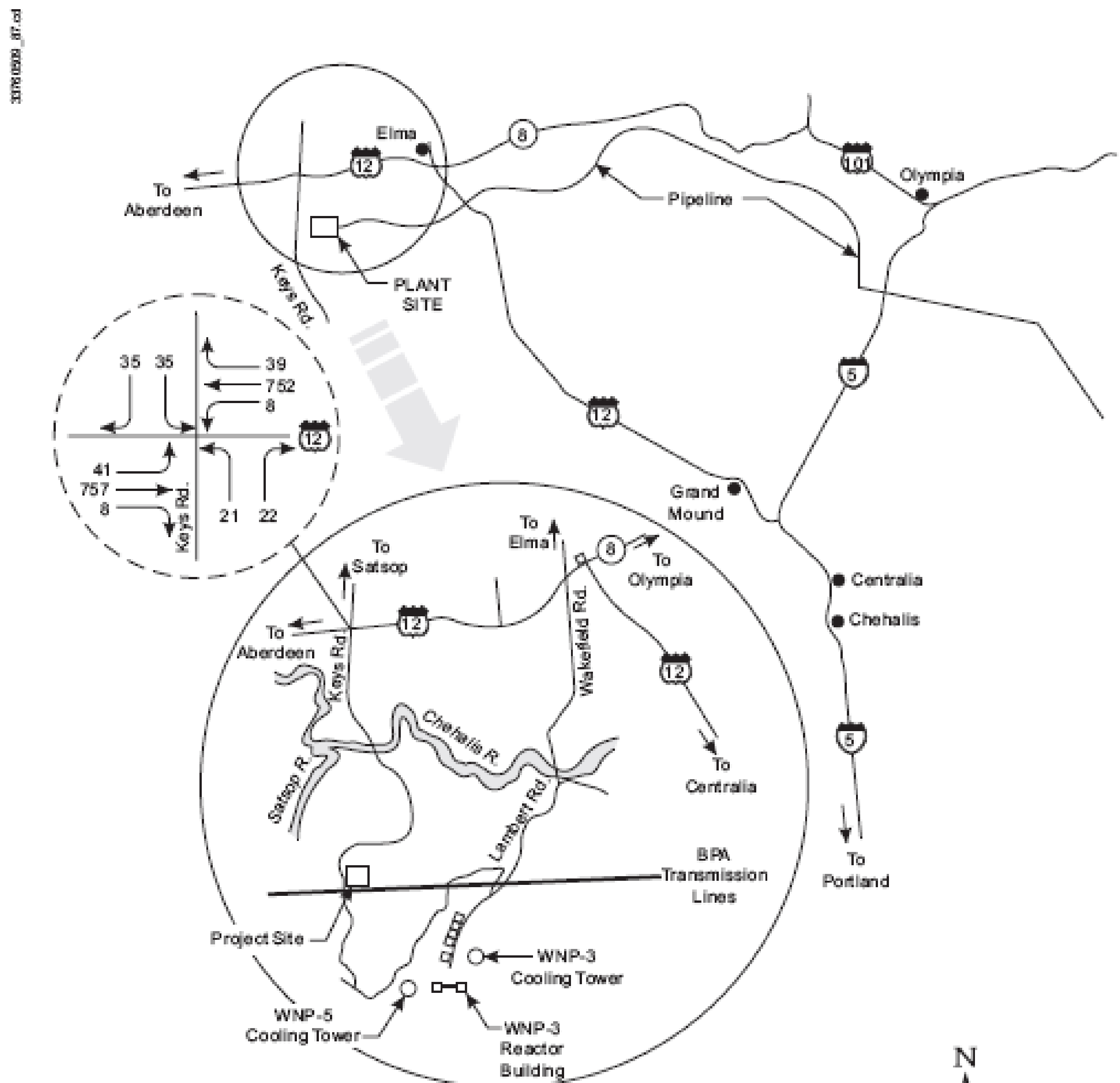


Figure 4.3-3 Estimated 2008 PM Peak Traffic Volumes – SR 12 and Keys Road



LEGEND:

XXX Estimated 2008 traffic volumes

Note: Estimated 2008 traffic volumes based on 1% per year growth over 2006 volumes.

TABLE 4.3-1
LEVEL OF SERVICE CRITERIA FOR TWO-WAY STOP-CONTROLLED INTERSECTIONS

Level of Service	Delay per Vehicle (seconds)	Expected Delay to Minor Street Traffic
A	< 10	Little or no delay
B	>10 and < 15	Short delay
C	>15 and < 25	Average delay
D	>25 and < 35	Long delay
E	>35 and < 50	Very long delay
F	>50	Extreme delay

Source: TRB (2000)

TABLE 4.3-2
EXISTING LOS AND CONTROL DELAY FOR SR 12 AND KEYS ROAD

Condition	Eastbound		Westbound		Northbound				Southbound			
	Left turn		Left turn		Left-turn		Right-turn		Left-turn		Right-turn	
	Control Delay[a]	LOS[b]	Control Delay[a]	LOS[b]	Control Delay[(b)]	LOS[b]	Control Delay[a]	LOS[b]	Control Delay[a]	LOS[b]	Control Delay[a]	LOS[b]
Existing 2008 (with Grays Harbor Energy Center operation)	10.1	B	9.6	A	47.3	E	11.2	B	33.9	D	33.9	D

a. Control Delay is measured in seconds per vehicle.
b. See Table 4.3-1 for LOS criteria.

Pedestrian Bicycle Facilities and Transit

The streets and highways serving the plant site have neither pedestrian nor bicycle facilities. Grays Harbor Transit Bus route 40 currently operates along SR 12, providing service between Hoquiam and Olympia. This route operates between 5:10 am and 8:25 pm in the eastbound direction, and between 6:15 am and 9:30 pm in the westbound direction on weekdays. Route 40 also operates between 8:00 am and 6:30 pm in the eastbound direction, and between 9:55 am and 8:20 pm in the westbound direction on weekends.

Intersection Improvements

Intersection improvements at SR 12 and Keys Road were implemented prior to construction of the Grays Harbor Energy Center. These improvements included dedicated left and right turn lanes on SR 12 in the eastbound direction, and a dedicated left turn lane on SR 12 in the westbound direction. The improvements also included a dedicated right turn lane on Keys Road in the northbound direction, and a flared approach for right turning vehicles in the southbound direction. These improvements were required prior to construction of the Grays Harbor Energy Center in an effort to reduce the number of accidents, and the delay to vehicles at the intersection of SR 12 and Keys Road.

Future Plans and Project

There is one project proposed in the project vicinity: a fish barrier is to be removed along SR 12 near Montesano (Nancy Thompson, personal communication). This project is proposed for the summer of 2011.

4.3.1.2 Impacts

Construction

Traffic estimates during construction of the additional two units include an approximate increase of 270 vehicles in the project vicinity during the pm peak hour. It is conservatively assumed for the purpose of analyses that all 270 vehicles would use the northbound approach to SR 12 on Keys Road. Under this assumption, operational analyses for the intersection of SR 12 and Keys Road indicate that LOS would degrade from D to F during the pm peak hour for both the northbound and southbound approaches to SR 12 on Keys Road. Without mitigation, unacceptable delays would result for left-turning vehicles at the northbound approach to SR 12 on Keys Road during the approximately two-year construction period.

The eastbound and westbound approaches to Keys Road on SR 12 and the northbound right turn movement would continue to operate at LOS B or better during construction of Units 3 and 4.

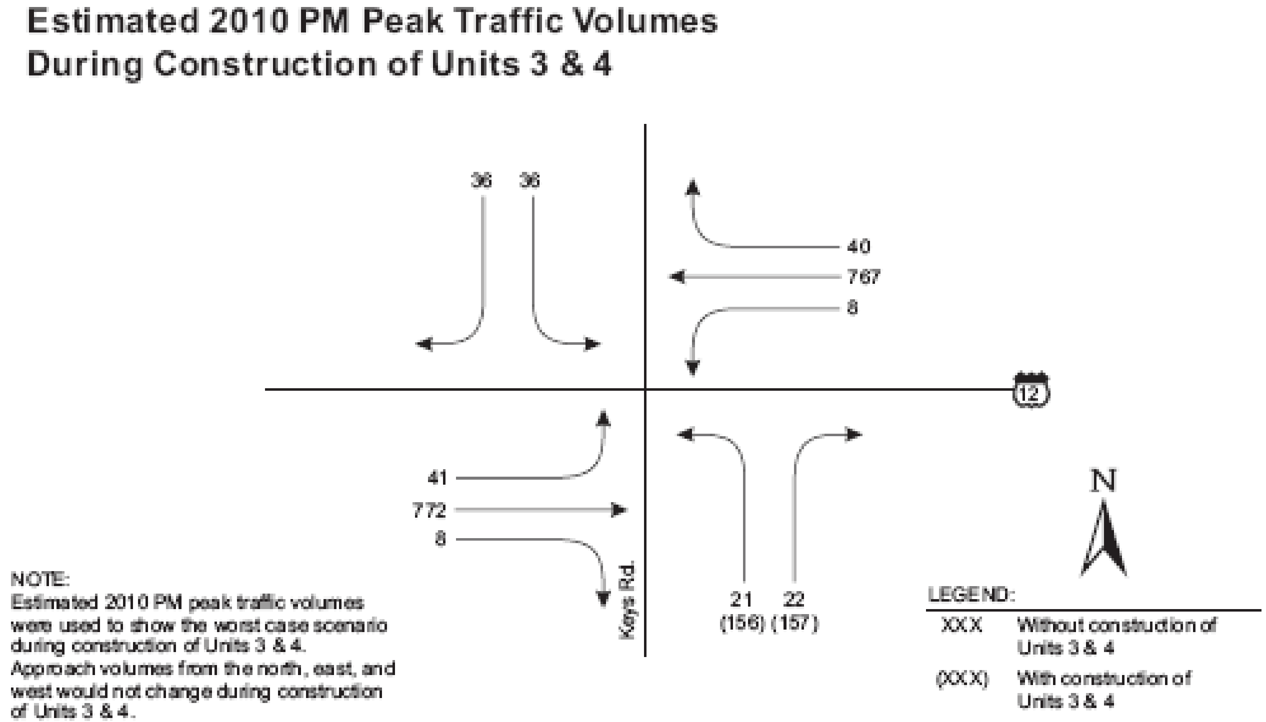
Operation

Traffic analyses for the operation of Units 3 and 4 only include those additional trips assumed to be associated with plant employees, and other services associated with the plant.

During operation of Units 3 and 4, an additional eight full-time employees will be required to be added to the existing staff of 23, for a total of 31 employees needed to operate all four units. Operation will involve two 12-hour shifts. For the purpose of determining a worst-case scenario, the operational analyses assumed that all trips would use the northbound approach to SR 12 on Keys Road. Estimated pm peak hour traffic volumes are shown on Figure 4.3-4.

Vehicles traveling on SR 12 on the approaches to Keys Road and northbound right turning vehicles on Keys Road would not experience noticeable changes in delay, or a change in LOS as a result of the operation of the Grays Harbor Energy Center. The eastbound and westbound approaches to Keys Road on SR 12 and the northbound right turn movement would continue to operate at LOS B or better (Table 4.3-3).

During project operation, estimated 2012 traffic volumes (including the eight additional employees) during the pm peak hour at the intersection of SR 12 and Keys Road would cause operations to degrade from 2008 existing conditions. Northbound left turning vehicles on Keys Road would experience an increase of approximately eight seconds of control delay per vehicle, and degradation in LOS from E to F. The overall northbound approach control delay would increase by approximately four seconds, with LOS remaining at D. Vehicles on the southbound approach to SR 12 on Keys Road would experience an increase of approximately four seconds of control delay per vehicle, and a degradation in LOS from D to E.



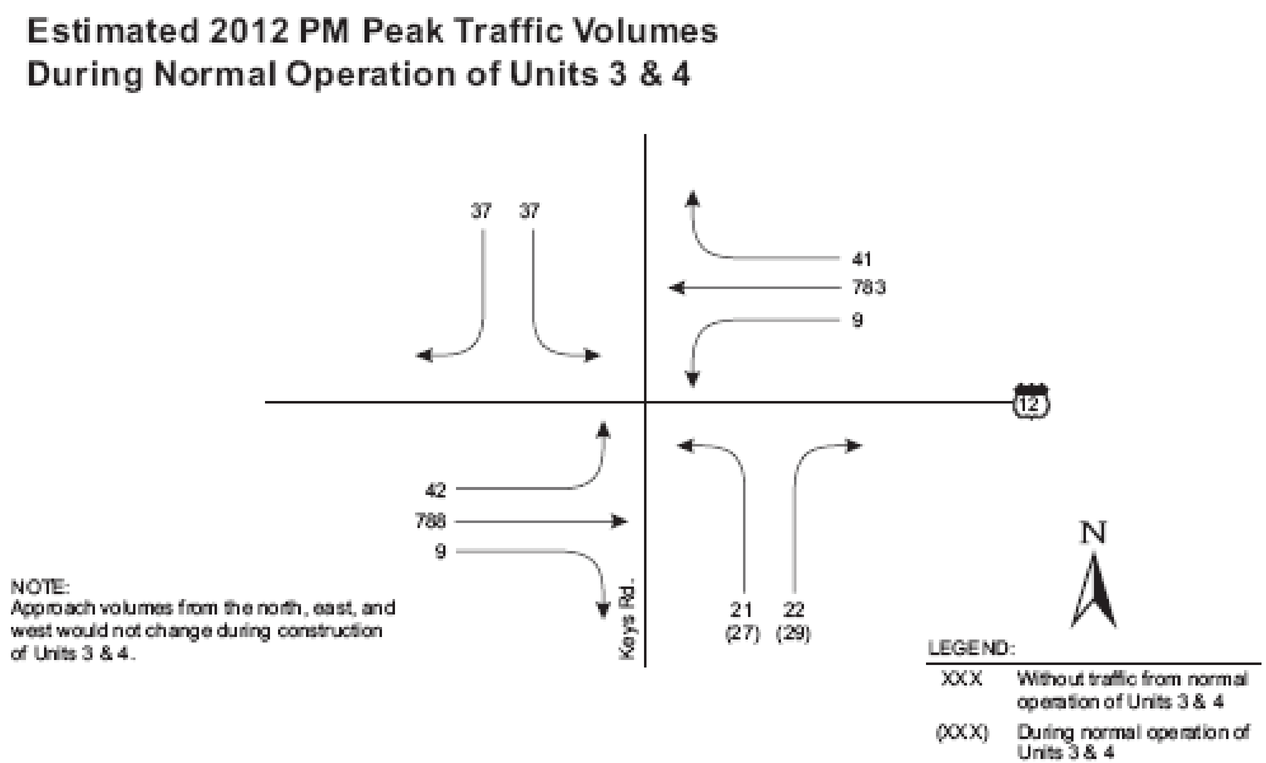


Figure 4.3-4
Estimated PM Peak Traffic Volumes – SR 12 and Keys Road

TABLE 4.3-3
EXISTING AND FUTURE LOS – SR 12 AND KEYS ROAD

Condition	Eastbound		Westbound		Northbound				Southbound			
	Left turn		Left turn		Left-turn		Right-turn		Left-turn		Right-turn	
	Control Delay[b]	LOS[a]	Control Delay[b]	LOS	Control Delay[b]	LOS	Control Delay[b]	LOS	Control Delay[b]	LOS	Control Delay[b]	LOS
Existing 2008 (with Grays Harbor Energy Center operation)	10.1	B	9.6	A	47.3	E	11.2	B	33.9	D	33.9	D
2010 During Construction of the additional two units (with Grays Harbor Energy Center operation)	10.1	B	9.7	A	1221.0	F	13.4	B	52.4	F	52.4	F
2012 During Operation of all 4 Units	10.2	B	9.8	A	57.0	F	11.5	B	39.2		39.2	E

a. See Table 4.3-1 for LOS criteria.
b. Control Delay is measured in seconds per vehicle.

During major maintenance projected to be required for the additional two units, an additional 50 people will be on site for approximately 28 days during the day shift. Maintenance-related traffic will not result in a reduction in LOS for the roads serving the site, provided that the majority of the maintenance staff does not leave the site and use the northbound approach to SR 12 on Keys Road during the pm peak hour. Adequate parking will be provided for both operations and major maintenance staff.

4.3.1.3 Mitigation Measures

Vehicular traffic during construction of the Units 3 and 4 will cause a degradation in LOS at the intersection of SR 12 and Keys Road during the pm peak hour. Prior to construction of the Grays Harbor Energy Center, a traffic management plan was submitted to EFSEC for review and was approved.

The traffic management plan approved for the Grays Harbor Energy Center also applies to construction of the additional two units. The main component of the traffic management plan included a recommendation to encourage the use of the Wakefield/Lambert corridor for site access and egress. It is recommended that vehicles traveling to/from the project site during construction of the additional two units and operation of the project use the Wakefield/Lambert corridor primarily, and avoid the intersection of SR 12 and Keys Road.

4.3.2 WATERBORNE, RAIL, AND AIR

4.3.2.1 Transport by Rail

The following description of planned rail and truck transport is based on known rail and roadway facilities and on estimates of the volume and number of shipments. The Certificate Holder will provide EFSEC with appropriate additional information as final transportation plans are developed.

A combination of rail and truck transport will be used to ship project-related equipment and materials from the manufacturers to the site. The equipment shipped by rail will include the CTG, STG, transformers, and the HRSG. The heaviest single load will be the HRSG modules, which will weigh approximately 221 tons each.

Items shipped by rail will be delivered to the existing Elma rail siding located approximately three miles northeast of the site. The existing facilities are adequate for project-related needs, and there is no need to develop additional rail access or rail facilities for the project. Shipment by rail will require approximately 25 to 30 railcars over a three- to six-month period (for materials to construct the additional two units). From the rail siding at Elma, heavy haulers will be contracted to deliver the items to the laydown area at the plant site using a route that follows SR 12 from Elma to Keys Road to the plant site, or using the Wakefield/Lambert corridor. These roads have the capacity to handle the size and weight of the trucked equipment and materials.

Trucks used for this transport will have the required number of axles to ensure compliance with highway and bridge design loading. The contracted hauling firms will be licensed to operate in the State of Washington and will be responsible for obtaining applicable permits and licenses.

4.3.2.2 Waterborne and Air Transport

Some construction materials or equipment may be delivered using the existing barge slip on the Chehalis River, and then trucked to the site. Construction of Units 3 and 4 will not require the use of air transport during construction or operation, with the possible exception of personnel transport on commercial flights and the use of commercial couriers that would use existing private or commercial flights for occasional small deliveries.

4.3.3 PARKING

4.3.3.1 Construction of Units 3 and 4

No parking will be permitted on the streets and roads serving the plant site. During construction of Units 3 and 4, parking will be made available on the 10-acre construction laydown area, or possibly through arrangements with the Satsop PDA to use the former construction laydown area located west of Keys Road. This large area was graveled and graded for use as a construction laydown area for nuclear projects WNP-3 and WNP-5. Approximately half of the area currently contains asphalt overlays. The laydown area has graveled internal roadways and access to and from Keys Road. Assuming an occupancy rate of 1.1 workers per vehicle, and approximately 270 additional vehicles during construction of Units 3 and 4, the work force would require approximately 300 parking spaces. The existing construction laydown area is adequate to provide parking for construction vehicles, and laydown space for Units 3 and 4 construction.

4.3.3.2 Operation of Units 3 and 4

Parking will be provided at the plant site for the additional eight employees, totaling 31 employees needed to operate all four units of the Grays Harbor Energy Center.

4.3.4 MOVEMENT/CIRCULATION OF PEOPLE OR GOODS

Construction of the proposed project will result in temporary and minor delays in traffic movement during delivery of oversized or heavy loads. During operation, the project will not have a significant impact on the movement or circulation of people or goods.

During construction and operation, the public will not be permitted in the areas associated with the power plants, including the transmission line right-of-way.

4.3.5 HAZARDS

4.3.5.1 Hazards to Traffic

Contractors will prepare a traffic control and parking plan that describes procedures to be followed during construction of Units 3 and 4 and associated facilities. This document will outline standard procedures that will allow for a safe working environment during construction activities such as transporting heavy equipment along roadways, establishing detours, and the use of flaggers. Implementation of the procedures in this plan will ensure that construction will not cause hazards to existing traffic.

Intersection improvements at SR 12 and Keys Road were implemented prior to construction of the Grays Harbor Energy Center in an effort to reduce the number of accidents, and the delay to vehicles at the intersection of SR 12 and Keys Road. These improvements included dedicated left and right turn lanes on SR 12 in the eastbound direction, and a dedicated left turn lane on SR 12 in the westbound direction. The improvements also included a dedicated right turn lane on Keys Road in the northbound direction, and a flared approach for right turning vehicles in the southbound direction.

4.3.5.2 Fuel and Waste

Fuel Oil

The Grays Harbor Energy Center will continue to use natural gas only. Small amounts of fuel oil will be used for the backup generators and fire-water pumps.

Waste Products

The SCA for the Grays Harbor Energy Center stipulates waste management procedures in accordance with Washington State regulations. A Comprehensive Dangerous Waste Management Program fulfilling all applicable regulatory requirements is in place for the Grays Harbor Energy Center site. This includes procedures for waste designation, labeling, storage, handling and disposal procedures, record keeping, inspection, contingency planning, management oversight, and transportation. This program will be applied to Units 3 and 4.

Hazardous materials will be transported by a licensed hazardous waste transporter, and when appropriate, hazardous materials will be disposed of at an approved and licensed disposal facility.

SECTION 4.4 SOCIOECONOMIC IMPACTS (WAC 463-60-535)

This section analyzes the impact of the construction and operation of Units 3 and 4 on local socioeconomic resources. The section analyzes impacts to local population, work force, property values, housing, the local economy, health and safety facilities and services, and education facilities and services.

4.4.1 EXISTING CONDITIONS

The Grays Harbor Energy Center is located in Grays Harbor County in southwestern Washington.

4.4.1.1 Population

Demographic Characteristics

The project site is located in Grays Harbor County, Washington. In 2000, the population of Grays Harbor County was approximately 67,200 individuals, 1.1 percent of the statewide population of approximately 5.9 million (WSOFM 2001a). In 2009, the estimated population of Grays Harbor County remained approximately 1.1 percent of the statewide population; with Grays Harbor County and Washington State population estimates at approximately 71,200 and 6.7 million, respectively (WSOFM 2009). Table 4.4-1 shows the population distribution in Grays Harbor County, its incorporated and unincorporated communities, and in Washington State.

In 2000, approximately 62 percent of the Grays Harbor County population lived in incorporated areas and approximately 40 percent of the population was located within the County's central population area; which includes Aberdeen, Hoquiam, and Cosmopolis (Table 4.4-1). In 2009, it is estimated that approximately 60 percent of the Grays Harbor County population was located within incorporated areas and the Aberdeen/Hoquiam/Cosmoplis area consisted of approximately 38 percent of the Grays Harbor County population (WSOFM 2009).

Growth Trends

Washington State's population grew approximately 13 percent from 2000 to 2009. In comparison, the population of Grays Harbor County grew by approximately 6 percent. The Grays Harbor County population declined in the 1980s, largely due to a timber industry downturn and related economic slowing and has continued to lag behind the growth of the state overall.

TABLE 4.4-1
POPULATION DISTRIBUTION IN THE PROJECT VICINITY

Jurisdiction	2000 Population[a]	2007 Population[b]
Grays Harbor County	67,194	71,200
Unincorporated	25,578	28,205
Incorporated	41,616	42,995
Aberdeen	16,461	16,440
Cosmopolis	1,595	1,640
Elma	3,049	3,110
Hoquiam	9,097	8,765
McCleary	1,454	1,555
Montesano	3,312	3,565
Oakville	675	715
Ocean Shores	3,836	4,860
Westport	2,137	2,345
Washington State	5,894,121	6,668,200
Unincorporated	2,379,012	2,552,500
Incorporated	3,515,109	4,115,700

a. Source: WSOFM (2001a)
b. Source: WSOFM (2009)

Between 2009 and 2020, the state's population is expected to grow by an additional 15 percent (1,030,739 individuals). The Grays Harbor County projected growth rate for the same period (2009 to 2020) is was expected to be 9 percent (6,350 individuals).

4.4.1.2 Housing

In 2000, Grays Harbor County had over 32,000 housing units (1.3 percent of Washington State's housing units). The vacancy rate in Grays Harbor County (17 percent) was 10 percentage points higher than the State's rate of 7 percent (Table 4.4-2). More recent housing data will not be available until the completion of the 2010 census. An analysis of existing housing stock based on age and value was not performed because the project is not expected to have a significant impact on housing in the project area.

TABLE 4.4-2
HOUSING CHARACTERISTICS IN THE PROJECT VICINITY, 2000

Jurisdiction	Total Housing Units	Total Occupied Units	Vacancy Rates	Owner Occupied	Renter Occupied	Average Household Size
Grays Harbor County	32,489	26,808	17%	18,495	8,313	2.48
Washington State	2,451,075	2,271,398	7%	1,467,009	804,389	2.53

Source: WSOFM (2001a)

4.4.1.3 Employment and Income

Employment and income in Grays Harbor County indicate the health, character, and direction of the local economy and, to an extent, are a determining factor in the welfare and quality of life of area residents.

In 2008, non-agricultural employment was 23,812 in Grays Harbor County (Grays Harbor Economic Development Council 2009). In 2008, Grays Harbor County's employment was highest in government (25 percent of total employment), manufacturing (15 percent of total employment), and retail trade (11.5 percent of total employment). Approximately 17% of the jobs in Grays Harbor County are associated with the travel and tourism industry.

For 2008, the unemployment rate in Grays Harbor County averaged 8.3% in comparison to Washington's average of 5.5% (Grays Harbor Economic Development Council 2009).

In 2008, the median household income in Grays Harbor County of $43,199 was approximately 72 percent of Washington State's median household income of $60,010. According to the Grays Harbor Demographic Profile, published in May 2009 by the Grays Harbor Economic Development Council, the average wage for all industries for 2008 was $32,520 per year. The highest wages were in manufacturing ($43,611) and wholesale trade ($41, 697).

4.4.1.4 Public Services and Utilties

Fire

The plant site lies within the boundaries of Grays Harbor County Fire Prevention District #5 - Porter/Bush Creek/Satsop. These fire stations are relatively small, and are staffed by volunteer fire fighters. Table 4.4-3 presents data on the fire protection districts and departments that exist in the project vicinity. The existing emergency response plans will continue to be implemented during operation to protect plant employees and structures in emergency situations. (See Section 4.1.6, Emergency Plans).

Police

Five separate law enforcement agencies provide police protection to communities in the project vicinity. Unincorporated regions in Grays Harbor County are served by the Grays Harbor County Sheriff's Department. The nearby cities of Montesano, Elma, and McCleary are each served by separate municipal police departments. The nearby community of Satsop does not have its own police department, and is served by the Grays Harbor County Sheriff's Department. District #8 of the Washington State Patrol provides police services along SR 8, SR 12, and other state highways in the project vicinity. In addition, security will be provided by contract service during construction of the project.

Emergency Medical Services

Emergency medical services are provided in the project vicinity by primary response ambulance units and area hospitals. In most cases, ambulance units are operated through local fire departments. Ambulance service providers in the vicinity of the project are listed in Table 4.4-4.

TABLE 4.4-3
FIRE DEPARTMENTS IN THE PROJECT VICINITY

Fire Department	Paid Full-Time Personnel	Volunteer Personnel	Equipment	Protection Class[a]
Grays Harbor County FPD #5 - Porter/Elma/Satsop	55	47	2 - 1,000 gal. Pumper 1 - 750 gal. Pumper 1 - 3,000 gal. Tanker 1 - 2,000 gal. Tanker 1 - 1,500 gal. Tanker 1 - Utility Van	8
Montesano Fire Department	5	38	2 - 750 gal. Pumpers 1 - 75’ Aerial with 500 g tank 1 - 2,500 gal. Tanker with 500 g pumps 1 - Rescue Vehicle 2 - Ambulances 1 - Aid Car 1 - Staff Vehicle	5
Elma Fire Department	0	25	1 - 750 gal. Pumper 1 - 500 gal. Pumper 1 - 2,000 gal. Tender 1 - Rescue Vehicle 1 - Command Vehicle	6
Grays Harbor County FPD #12 - McCleary/McCleary Fire Department	0	25	1 - 850 gal. Pumper 1 - 500 gal. Pumper 1 - 1,500 gal. Tanker 1 - 1,250 gal. Tankers	8

Fire Department	Paid Full-Time Personnel	Volunteer Personnel	Equipment	Protection Class[a]
Grays Harbor County FPD #2 - Wynochee/Central Park/Brady/outlying Montesano area	3?	45	3 - 1,000 gal. Pumpers 1 - 2,850 gal. Tender 1 - 2,500 gal. Tender 1 - 1,500 gal. Pumper 2 - Aid Car 1 - Utility Van 1 - Command Vehicle 1 – Water Rescue Trailer	8

Sources: Larry Willis, Steve Crass, Chris Brown, Tom Wilder, personal communications

a. As rated by the Washington Surveying and Rating Bureau in 2001. Fire district protection class ratings are used to evaluate fire protection availability for insurance purposes and are assessed to all municipal and rural areas by the Washington Surveying and Rating Bureau. Ratings range from 1 to 10, with class 1 representing the highest level of fire protection and class 10 the lowest level. A class 1 rating is rarely achieved. Ratings are based on the available water supply; the logistical characteristics and makeup of the district fire department; the available communications systems; and the fire control/safety measures taken and ordinances in effect in the particular fire district. Adequacy of fire protection indicated by the rating depends on the type of area rated. A rating of 8 or 9 is typical for a rural area. This low rating is usually due to the fact that standard fire hydrant service, required in more urban areas, is not available, and rural volunteer fire departments do not have full-time staff or formally equipped fire stations and facilities. The situation is further aggravated by access problems and reliance on volunteers who often must travel long distances to respond to calls, which leads to long response times and limited fire-fighting ability. A rating of 8 or above does not necessarily mean that fire protection is inadequate. It indicates that according to the standards of fire protection services, set up primarily for municipalities, an area lacks some of the conventional means of fire protection.

TABLE 4.4-4
AMBULANCE SERVICE PROVIDERS
IN THE PROJECT VICINITY

Name	Ownership	Level of Care
Montesano Ambulance Service	Public	ALS and BLS
East Grays Harbor Medic One	Public	ALS and BLS

Source: Jean Jones, personal communication
ALS – Advanced Life Support
BLS – Basic Life Support

Hospitals near the project area are located in Aberdeen, McCleary, and Olympia. Mark Reed Hospital in McCleary and Grays Harbor Community Hospital in Aberdeen are the closest hospitals to the Grays Harbor Energy Center site. Mark Reed Hospital is approximately 12 miles northeast of the Grays Harbor Energy Center. Grays Harbor Community Hospital is approximately 17 miles west of the Grays Harbor Energy Center site. Capitol Medical Center and Saint Peter Hospital, both in Olympia, are approximately 29 miles east of the Grays Harbor Energy Center site. Further information on these hospitals is presented in Table 4.4-5.

TABLE 4.4-5
HOSPITALS IN THE PROJECT VICINITY

County	Name	Location	No. of Beds
Grays Harbor	Grays Harbor Community Hospital	915 Anderson Dr., Aberdeen	150
	Mark Reed Hospital	322 S. Birch St., McCleary	24
Thurston	Capital Medical Center	3900 Capital Mall Dr. S.W., Olympia	119
	Providence Saint Peter Hospital	413 N. Lilly Road N.E., Olympia	390

Data from personal communications with hospital desk clerks or hospital web sites, October 31, 2001.

4.4.1.5 Schools

There are several schools and educational facilities in the project vicinity. Information on public school districts located close to the project is presented in Table 4.4-6. None of the individual school buildings in these districts is located directly adjacent to the proposed project. In addition to these public schools, there are also several private elementary and secondary schools in the project vicinity. Many of these private schools are affiliated with church or religious organizations. Higher education is available in the project corridor vicinity from Grays Harbor Community College in Aberdeen, and from South Puget Sound Community College, Evergreen State College, and Saint Martin's College in Thurston County. The closest schools to the Grays Harbor Energy Center site are in the Montesano, Satsop, Elma, and McCleary School Districts. Existing capacity for these districts is shown in Table 4.4-6.

4.4.1.6 Parks and Recreational

Parks and other recreational facilities are described in Section 4.2, Land and Shoreline Use, WAC 463-60-362.

TABLE 4.4-6
SCHOOL DISTRICTS IN THE PROJECT VICINITY

County	School District	2008–2009 Enrollment[a]	Capacity[b]	Excess Capacity
Grays Harbor	Montesano #66	1,360	1,819	459
	Satsop #104	52	104	52
	Elma #68	1,779	1,845	66
	McCleary #65	268	325	57

a. Source: WOSPI (2008)
b. Data from personal communications with individual school districts (November 5 to 7, 2001)

4.4.1.7 Maintenance

For the purposes of this document, maintenance is defined as the costs, in money and manpower, required for the upkeep of public facilities. This upkeep is often necessary for these facilities to continue providing services to the public into the future. Facilities such as roads, sidewalks, water and sewer mains, bicycle paths, and park benches, all come under the umbrella of public facilities that would require periodic maintenance. Many public agencies, such as counties and cities, have established plans that dictate when, for instance, a road should be resurfaced, or playground facilities should be replaced. These plans often tie into public budgets, thereby allocating funds obtained from taxpayers for the necessary public facility maintenance or improvements. Such plans are sometimes enforced with varying degrees of rigidity, being influenced by a variety of factors, some of which could be the actual need for facility improvement, budget and economic fluctuations, and changing public needs and interests. To facilitate the prudent handling of public funds, several layers of administrative review are often involved in the maintenance planning process. During this planning stage, public agencies generally inspect the facilities over which they have jurisdiction, determine the relative maintenance needs, and then rank these facility maintenance needs with other potential uses for public funds based on an established list of criteria. Maintenance projects determined to have the highest priority would then receive the necessary funding and administrative go ahead. Other projects, deemed less critical, could then receive consideration after high priority projects are completed.

Maintenance plans and schedules are frequently influenced by outside forces, which may damage or in some way render inadequate certain public facilities. Such forces could be sudden population growth, new facility construction, and even natural disasters. In order to fairly assign the payment responsibility for maintenance beyond regular periodic upkeep, public agencies use a variety of widely accepted methods. Obviously, as in the case of natural disasters, there can be times when no party can be deemed as being responsible. However, when such a responsible party can be determined, some agencies might choose to assess mitigation fees to that party. Other agencies opt to make an agreement with such a responsible party, to grant a permit for their action only if the facility that would be damaged or rendered inadequate were replaced or reproduced in another location, at the responsible party's expense. Whichever method is used, the justification is usually the same: the responsible party caused the situation requiring the additional cost, and they should therefore be responsible for covering that cost.

The Public Works department has, as part of regular operations, maintenance programs for the public facilities for which they are responsible. These programs provide for regular inspection of public facilities in general, and maintenance and repair on an as-needed basis.

4.4.1.8 Communications

Telephone service to the Grays Harbor Energy site, Satsop Development Park, and adjacent residential neighborhoods is provided by CenturyTel.

4.4.1.9 Water/Stormwater

The existing water system and the existing stormwater control systems are discussed in Section 2.5, Water Supply System, WAC 463-60-165; Section 2.10, Surface Water Runoff, WAC 463-60-215; and Section 3.3, Water, WAC 463-60-322.

4.4.1.10 Sewer/Solid Waste

The Grays Harbor Energy Center site is not served by a sewer system. The Grays Harbor Energy Center will continue to use septic systems and leach fields for sanitary waste.

A solid waste contractor removes solid waste from the site for disposal at an approved and regulated landfill.

4.4.2 IMPACTS

Impacts to the local socioeconomic environment attributable to Units 3 and 4 would include increased local employment and associated income, spending for local services and materials, and tax revenues. Impacts were estimated by reviewing the components of the construction and operation of Units 3 and 4 and comparing the impacts to existing conditions.

Potential socioeconomic impacts on population, housing, and property values that would be attributable to the additional two units are broken down between the construction impacts and operation impacts.

4.4.2.1 Construction

Local Economy

The construction of Units 3 and 4 would have beneficial impacts on the local socioeconomic environment of Grays Harbor and Thurston Counties, including additional employment and associated income and spending at local merchants' establishments.

The construction period would potentially begin in August 2010, depending on acquisition of permitting approvals and power offtake contracts, and would last approximately 22 months (through June 2012). Peak construction employment would occur from August 2010 through March 2012, assuming an August 2010 construction start date. The construction work force would consist of boilermakers, carpenters, cement masons, electricians, insulators, ironworkers, laborers, millwrights, operating engineers, painters, and pipefitters, in addition to non-craft staff. Table 2.12-1 in Section 2.12 shows the breakdown between the craft and non-craft work force. Figure 2.12-2 in Section 2.12 shows the total construction work force on site by month.

To ensure that the construction work force originates from the local labor pool to the extent possible, the Certificate Holder would require construction contractors to advertise positions locally and to hire local workers where practicable and possible. Although some construction skills are specialized and might not be available within the local or state labor pools, hiring priority for construction would be given to qualified local and in-state construction workers. Therefore, most of the construction work force would probably come from inside the state of Washington

The influx of the out-of-area construction workers into communities near the project site would generate additional spending and business activity for temporary housing establishments such as hotels and motels, recreational vehicle parks, and campgrounds. Other service providers and retailers such as gas stations and food stores/restaurants would experience an increase in revenues during the construction phase due to construction workers' spending during the day. Many of the purchases and rental of required construction materials and equipment also would be made locally, thus generating additional revenue for local suppliers.

Total construction employment would account for approximately $22 million in pre-tax wages and salaries (labor income). With much of the construction labor expected to come from local sources, it is expected that a large portion of the wages and salaries earned during construction would be spent locally, or in other parts of the state.

Local non-salary expenditures associated with construction are expected to total about $28 million, with about $20 million for materials and supplies and about $8 million for subcontracted services. These expenditures would likely occur within a radius of approximately 50 miles from the site. The remainder of the construction cost would likely be spent outside the state on high capital cost items such as turbine generators, HRSGs, and civil and mechanical structures. Project-related expenditures would generate sales taxes during construction, with a portion paid as Washington State and local sales taxes. These positive impacts to Grays Harbor County would be temporary, lasting until construction is complete.

Population and Housing

Up to 20 percent of the construction work force (approximately 100 workers, measured during the peak month) would be from outside of the local area. The presence of 100 workers is a "worst-case" scenario because the number 100 is based on the peak number of workers, and some percentage of the 100 non-local workers would likely continue to reside in their permanent residence and commute daily throughout the construction period. A small percentage of these 100 workers could bring their families with them while working on the project, and would commute daily from their new, temporary residence. However, most of these workers are expected to live in western Washington and would likely commute on a weekly basis.[4] A

[4] Weekly commuters would drive to the job site on Monday morning, stay in nearby temporary housing during the week, and return home on Friday evening.

temporary increase in population would occur in the local area during the week due to the construction work force.

As described in the recreation portion of Section 4.2, Land and Shoreline Use, WAC 463-60-362, the use of recreation facilities by construction workers would be temporary and is not expected to result in a significant impact. Housing vacancy rates in Grays Harbor County are 17 percent, indicating that sufficient housing is available in the general area for the portion of the non-local construction work force that could choose to live in permanent housing. Workers could find temporary housing in Montesano, Satsop, Elma, and McCleary, as well as in the Aberdeen-Hoquiam area and the Olympia-Tumwater area. Due to 1) the large number of recreational facilities and the availability of sufficient housing in the general area, 2) the relatively low number of construction workers from outside the local area that would seek temporary housing, and 3) the relatively short seven-month period of peak construction, construction of the proposed project is not expected to result in a significant impact on housing. Furthermore, Units 3 and 4 would be constructed on an existing plant site and would not displace or directly affect surrounding residences.

Property Values

The potential for long-term impacts on property values is addressed below in Section 4.4.2.2, Operation. Construction activities may result in a temporary and minor impact on property values for property owners attempting to sell property located in the vicinity of the plant site during the peak periods of construction. However, the impact on property values in the area would be temporary and is expected to be minor.

Public Services and Utilities

Because no extensive demand on any public service or utility is anticipated, and a traffic control plan will be implemented, the overall impact to the public services and utilities is expected to be minor and short-term. Impacts were determined through a detailed review of the proposed additional units against existing conditions and a subjective assessment based on professional experience with other similar projects.

A portion of the construction work crew is expected to come from out-of-state areas, and the influx of construction workers into neighboring communities will result in a minor and temporary increase in the demand placed on local public service providers. This demand increase will have a minor and temporary effect on local police departments, providers of emergency medical services, and local fire departments. The impact of project construction on local schools would be at most minor and temporary, as few out-of-state construction workers are expected to be accompanied by families.

Construction is not expected to create any additional maintenance needs for public facilities. During construction, trucks would use county roads to reach the site and pipeline corridor locations. Grays Harbor County does not have a specific schedule for making repairs to local roads. Repairs are done on an as-needed basis determined by local inspections. Construction traffic is not expected to damage the local road system. If such damage occurs, the applicant would either repair the damage or provide funds to the local Public Works Department to repair the damage.

Section 4.2, Land and Shoreline Use, WAC 463-60-362, addresses the potential for impacts on parks and other recreational facilities. As described in that section, construction and operation of Units 3 and 4 will not result in a significant impact on recreational facilities.

No significant adverse impacts to local communication, potable water, sanitary sewer, or solid waste collection systems are anticipated.

In summary, due to the short duration of the project's construction phase and the relatively small size of the proposed construction crew, the overall adverse impact on local public services and utilities caused by construction is not expected to be significant.

4.4.2.2 Operation

Local Economy

Operation of the proposed Units 3 and 4 would result in a positive economic impact to Grays Harbor County and the state due to increased tax revenues, employment, and local expenditures. The Grays Harbor Energy Center is currently assessed at approximately $337 million. After completion of construction of Units 3 and 4, the value of the Grays Harbor Energy Center would be over $500 million. Operation of the proposed Units 3 and 4 would involve approximately eight additional employees working two 12-hour shifts, with a maximum of 31 employees working on site at any time. The operational labor force would include the following positions: plant manager, operations supervisor/engineer, control operators, auxiliary operators, maintenance supervisor, mechanical and electrical technicians, and clerks. Efforts would be made to hire local individuals to staff the project as much as practicable.

The plant would require periodic maintenance and a scheduled major maintenance outage during the sixth year of operation. During maintenance outage, 20 to 50 additional workers would be on site for 28 days during the day shift. Thus, the presence of additional on-site daytime employment (maintenance crews) would increase local spending during this period.

Total operating and maintenance costs for the four units would be approximately $40 million per year. Of this, about $3 million per year would be in salaries and wages. Generating and Business and Occupation taxes are expected to total approximately $2 million per year.

Population and Housing

Operation of Units 3 and 4 would require adding approximately eight employees to the existing Grays Harbor Energy Center staff of 23, for a total of 31 employees. Efforts would be made to hire local individuals to staff the project as much as practicable. Operation employees would likely choose to reside in various areas from Aberdeen to Olympia, based on an approximately 40-minute drive to work. Even if all eight additional employees come from outside of the local area, and they all bring families (8×2.5 persons per household = 20), the potential impact area is sufficiently large (with a population of over 67,200 and over 5,500 estimated available housing units) that the operation of Units 3 and 4 would not have an adverse impact on population or housing in the area (WSOFM 2001c). The number of vacant housing units was estimated by applying the vacancy rate (1 – occupancy rate = vacancy rate) to the number of housing units.

Property Values

The values of homes near the Satsop Development Park property have been affected by the nearby nuclear power plants and related facilities. The values of homes nearest the proposed plant site have been affected by three major conditions: 1) the presence of the BPA transmission line right-of-way, which is adjacent to many of the residences and includes two rows of steel transmission towers and a row of wooden power poles; 2) the presence of the construction laydown area for the nuclear plants—an area that includes steel buildings, graveled storage areas, chain link fencing, and stockpiled materials; and 3) the presence of the nuclear plants, cooling towers, and associated facilities approximately 1 mile southeast. In addition, property values have been influenced by Grays Harbor County's growth plans that include use of the Satsop Development Park property for commercial and industrial development.

As a result of the existing influences on the value of homes and property in the vicinity of the Grays Harbor Energy Center site, it is unlikely that adding two units would result in a significant impact on property values.

Public Services and Utilities

Operation of the Grays Harbor Energy Center will not have a significant adverse impact on existing public services in the project vicinity. Grays Harbor Energy staff will receive appropriate training in handling on-site emergencies, including fire and medical, and will provide the first line of response. As part of the Grays Harbor Energy Center construction, the Certificate Holder initiated consultation with the local fire departments concerning training, equipment and plant familiarity. This consultation will be expanded to include Units 3 and 4.

Because there will be a relatively small staff operating the Grays Harbor Energy facility, no effect on schools in the project vicinity is expected.

The Grays Harbor Energy Center will include a septic system and leach field for each plant. These will be constructed and operated in accordance with applicable regulations and will not affect the existing septic systems.

Operation of the proposed project would result in a positive economic impact to Grays Harbor County and the state due to increased tax revenues, employment, and local expenditures. A portion of these funds may be used to upgrade existing public services and utilities.

5.0 PERMIT APPLICATIONS

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

5.1.1 INTRODUCTION

Grays Harbor Energy LLC proposes to add two combustion turbine generators (Units 3 and 4) and a single steam generator to the existing Grays Harbor Energy Center. This will increase the maximum electrical generation capacity by approximately 650 MW, doubling the project's generating capacity to 1,300 MW.

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

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

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

5.1.1.1 Organization

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

Key components of the PSD permit application are as follows:

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

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

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

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

- Section 5.1.5 addresses additional impacts related to growth.

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

5.1.1.2 Summary of Findings

The air quality impact assessments that follow indicate:

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

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

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

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

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

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

5.1.2 EMISSIONS

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

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

5.1.2.1 Normal Operation and Short-term Emission Rates

Power Generation Units

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

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

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

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

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

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

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

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

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

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

In addition to the type of turbine, the ambient air temperature also affects the emissions. Three temperatures were chosen to evaluate the full range of expected operating conditions: a low temperature of 20ºF, the rated temperature of 59ºF, and a high temperature of 90ºF. Emissions were consistently highest with an assumption of an ambient air temperature of 20ºF.

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

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

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

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

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

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

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

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

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

a. For the TAPs analysis, CO, NO_X, and SO_2 emission rates are the worst-case emission rates for the corresponding criteria pollutants.

b. The formaldehyde emission factors were reduced by 85% to reflect control provided by the oxidation catalyst – see page 7, AP-42 Section 3.1.

c. One third of SO_2 emissions were assumed to be converted to sulfuric acid based on NPS guidance for speciation of emissions from natural gas-fired turbines (http://www.nature.nps.gov/air/Permits/ect/ectGasFiredCT.cfm).

Auxiliary Boiler

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

TABLE 5.1-3
CRITERIA POLLUTANT EMISSIONS FROM AUXILIARY BOILER

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

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

b. Based on annual average sulfur content of natural gas (1.04 grains per 100scf)

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

d. Natural gas heating value used to calculate these emissions is 1024 Btu/cf

e. Annual emissions based on 2,500 hours of operation per year

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

TABLE 5.1-4
TAP AND HAP EMISSIONS FROM AUXILIARY BOILER

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

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

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

Emergency Diesel Engines

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

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

TABLE 5.1-5
CRITERIA POLLUTANT EMISSIONS FROM EMERGENCY DIESEL ENGINES

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

a. Emission factors based on 40 CFR Part 60 Subpart IIII, Table 4 (except SO2, see note c)
b. Annual emissions based on 26 hours of generator testing/maintenance.
c. Conservatively assumed both NO_X and VOC emissions equal the Subpart IIII limit on the sum of NO_X and VOC.
d. SO2 based on AP-42 Section 3.4, Table 3.4-1 and fuel sulfur content of 0.015% by weight (8.09e-3 × %S). The SO_2 emission factor from AP-42 Section 3.3 was not used because it is based on an unknown fuel sulfur content, and the Section 3.4 emission factor assumes complete conversion of sulfur to SO_2.
e. Filterable $PM_{2.5}$ emissions were assumed to be 25% of PM_{10} emissions, and total $PM_{2.5}$ emissions were assumed to be equal to PM_{10} emissions.

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

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

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

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

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

Cooling Towers

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

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

TABLE 5.1-7
PARTICULATE MATTER EMISSIONS FROM THE COOLING TOWER

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

Short-Term Emissions Summary

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

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

Operating Mode	24-hr NO_x	1-hr CO	8-hr CO	1-hr SO_2	3-hr SO_2	24-hr SO_2	24-hr PM_{10}	24-hr PM2.5	1-hr VOC
Combustion Turbines[a]	40.0	24.4	24.4	28.3	28.3	26.1	38.0	9.50	6.96
Auxiliary Boiler	0.32	1.1	1.1	0.17	0.17	0.16	0.15	0.037	0.12
Emergency Generator[b]	0.16	3.5	0.43	0.0073	0.0024	0.00030	0.0082	0.0082	3.9
Firewater Pump[b]	0.057	1.2	0.15	0.0033	0.0011	0.00014	0.0075	0.0075	1.4
Cooling Tower	--	--	--	--	--	--	0.8	0.8	--
Total	40.6	30.1	26.0	28.5	28.5	26.3	39.0	10.3	17.2

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

5.1.2.2 Startup

Emission rates of some pollutants are higher during startup than during normal operations because combustion is not yet optimized and/or because control equipment is not functional under all operating conditions. Like automobiles, combustion turbines emit more carbon monoxide during startup because combustion is optimized for a warm engine and the typical higher loads (usually 60 percent load or greater), and the oxidation catalyst is not as effective at low exhaust gas temperatures. Similarly, combustion turbine NO_x emission rates are also higher during startup, primarily because the SCR system is not effective at low exhaust gas temperatures, and ammonia is generally not introduced until temperatures that promote the desired reactions are achieved.

The duration and total emissions from a combustion turbine startup depend on how long it has been shut down. Table 5.1-9 identifies startup emissions and the duration of a combustion turbine startup. Note that once the combustion turbines reach 60 percent load, the SCR and oxidation catalyst will be operational and the combustion turbine emission rates will meet the proposed emission limits.

TABLE 5.1-9
COMBUSTION TURBINE TOTAL STARTUP/SHUTDOWN EMISSIONS

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

Emissions in pounds per event for the Units 3 and 4 combustion turbines.
a. Cold start – startup following a 72 hour or greater period of non-operation. Hot start – startup following 8 hours or less of non-operation. Warm start – startup following between 8 and 72 hours of non-operation.
b. Time for both turbines to reach 100% load for startup, and for both turbines to go from 100% load to no operation for shutdown.
c. SO2 startup/shutdown emissions are based on the following assumed fractions of maximum full load operation emissions: cold start – 50%, warm start – 58.5%, hot start – 67%, shutdown – 70%.

Units 3 and 4 may be used to meet peak daily electrical demand, which will require frequent startups and shutdowns. Table 5.1-10 identifies short-term average emission rates for an operating scenario in which the combustion turbines are started, operated, and shut down. In cases where the averaging periods would not accommodate all three phases of operation (i.e., startup, operation, and shutdown cannot all always occur during a 1, 3, or 8-hour averaging period), time-weighted emission rates for combinations of startup and operation, operation and then shutdown, or startup were calculated. Review of the table indicates CO emissions are much higher during startups than during normal operations; NO_x and VOC emissions are higher but the increase is not as significant as with CO. Because SO_2 emissions depend solely on the quantity of fuel used, the lower operating rate during startup results in lower SO_2 emissions. PM emissions are also lower during startup.

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

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

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

In order to account for the influence of startup and shutdown on annual average emission rates, potentially unrealistic scenarios were developed. Because the number and type (hot, warm, cold) of startups and shutdowns that will actually occur in a given year are difficult to predict, it was thought that scenarios with unrealistically frequent startup and shutdown events would, when viewed alongside the annual average emission rates developed for continuous annual operation (which are unrealistic in that they assume there are no startups or shutdowns), serve to bound the continuum of possible annual operations. Table 5.1-11 summarizes the annual emission rates calculated for various startup/operation/shutdown scenarios, and identifies the maximum emission rates for each pollutant. In all cases, the operating period between startup and shutdown was assumed to be 16 hours, and the operating scenario was assumed to be full load with duct burning. As shown in the table, almost all of the maximum emission rates result from hot starts followed by 16 hours of operation, then shutdown followed immediately by another hot startup, and a repeat of the cycle for an entire year. The exception is for CO, where the scenario in which the cycle begins with a warm start and ends with 10 hours of downtime is slightly higher than the hot start scenario with no downtime.

TABLE 5.1-11
ANNUAL COMBUSTION TURBINE EMISSION RATES
CONSIDERING STARTUP AND SHUTDOWN

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

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

5.1.2.3 Annual Emissions

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

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

	NO_x	CO	SO_2	PM_{10}	$PM_{2.5}$	VOC
Annual emissions with continuous CT operation (8,760 hours per year)						
Combustion Turbines[a] w/Duct Firing	175	107	62.8	166	41.6	30.5
Combustion Turbines[a] @ 100% Load	139	84.6	48.5	166	41.6	24.2
Combustion Turbines[a] @ 60% Load	98.8	60.1	34.5	166	41.6	51.5
Maximum Combustion Turbines[a] Scenario	175	107	62.8	166	41.6	51.5
Auxiliary Boiler[b]	0.40	1.4	0.21	0.18	0.046	0.15
Emergency Generator[c]	0.051	0.045	0.000095	0.0026	0.0021	0.051
Firewater Pump Engine[c]	0.018	0.015	0.000043	0.0024	0.0020	0.018
Cooling Tower[d]	--	--	--	3.5	3.5	--
Total Emissions	176	108	63.0	170	45.1	51.7
Annual Emissions with worst case startup and/or shutdown schedule						
Combustion Turbines[a]	166	450	43.7	116	29.0	52.9
Auxiliary Boiler[b]	0.40	1.4	0.21	0.18	0.046	0.15
Emergency Generator[c]	0.051	0.045	0.000095	0.0026	0.0021	0.051
Firewater Pump Engine[c]	0.018	0.015	0.000043	0.0024	0.0020	0.018

Cooling Tower[d]	--	--	--	3.5	3.5	--
Total Emissions	166	451	43.9	120	32.5	53.1

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

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

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

5.1.2.4 Emission Standards

New Source Performance Standards

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

Subpart A, General Provisions

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

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

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

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

Subpart KKKK, Standards of Performance for Stationary Combustion Turbines

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

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

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

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

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

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

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

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

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

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

TABLE 5.1-13
FACILITY-WIDE HAP EMISSIONS

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

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

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

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

Title 4 (Acid Rain) Provisions

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

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

Title V Air Operating Permit

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

State and Local Emission Limits

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

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

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

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

The maximum PM_{10} emission rate from each combustion turbine would be (at most) about 19.0 lb/hr, including sulfates. Given flow rates of between approximately 1.0 and 0.7 million actual cubic feet per minute (acfm) from each turbine (depending upon the mode of operation), this emission rate corresponds to particulate loadings of less than 0.1 grains/actual cubic foot (gr/acf). Adjusting for standard temperature and dry exhaust, particulate matter emissions from each unit would be less than 0.0031 gr/dscf at 15 percent O_2. Thus, the anticipated grain loading is less than 4 percent of the 0.1 gr/dscf allowed by the state regulation. Plume opacity associated with grain loadings this low would be less than 5 percent, which is well below the allowed 20 percent. The anticipated SO_2 concentration would also be well below the state limit of 1,000 ppm.

Notice of Construction and Application for Approval

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

Prevention of Significant Deterioration (PSD)

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

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

TABLE 5.1-14
PSD REVIEW APPLICABILITY ANALYSIS

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

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

5.1.2.5 Toxic and Hazardous Air Pollutants (TAPs)

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

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

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

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

5.1.3 LOCAL AIR QUALITY IMPACT ASSESSMENT

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

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

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

5.1.3.1 Model Selection

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

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

5.1.3.2 Modeling Procedures

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

Model Setup and Application

The most recent version of AERMOD (Version 07026) was applied with the default options for dispersion that depend on local meteorological data, regional upper air data, and the local physical characteristics of land use surrounding the facility. AERMOD contains several options for urban dispersion that were not selected for these analyses. The facility is located near Elma, Washington, and the majority of the study domain is agricultural land, rangeland, or forest. The effects of surface roughness and other physical characteristics associated with the types of land use in the modeling domain were included in the analysis as part of the meteorological database, described in Section 5.1.3.4.

Averaging Periods

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

Chemical Transformations

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

5.1.3.3 Elevation Data and Receptor Network

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

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

5.1.3.4 Meteorological Data

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

Surface Data

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

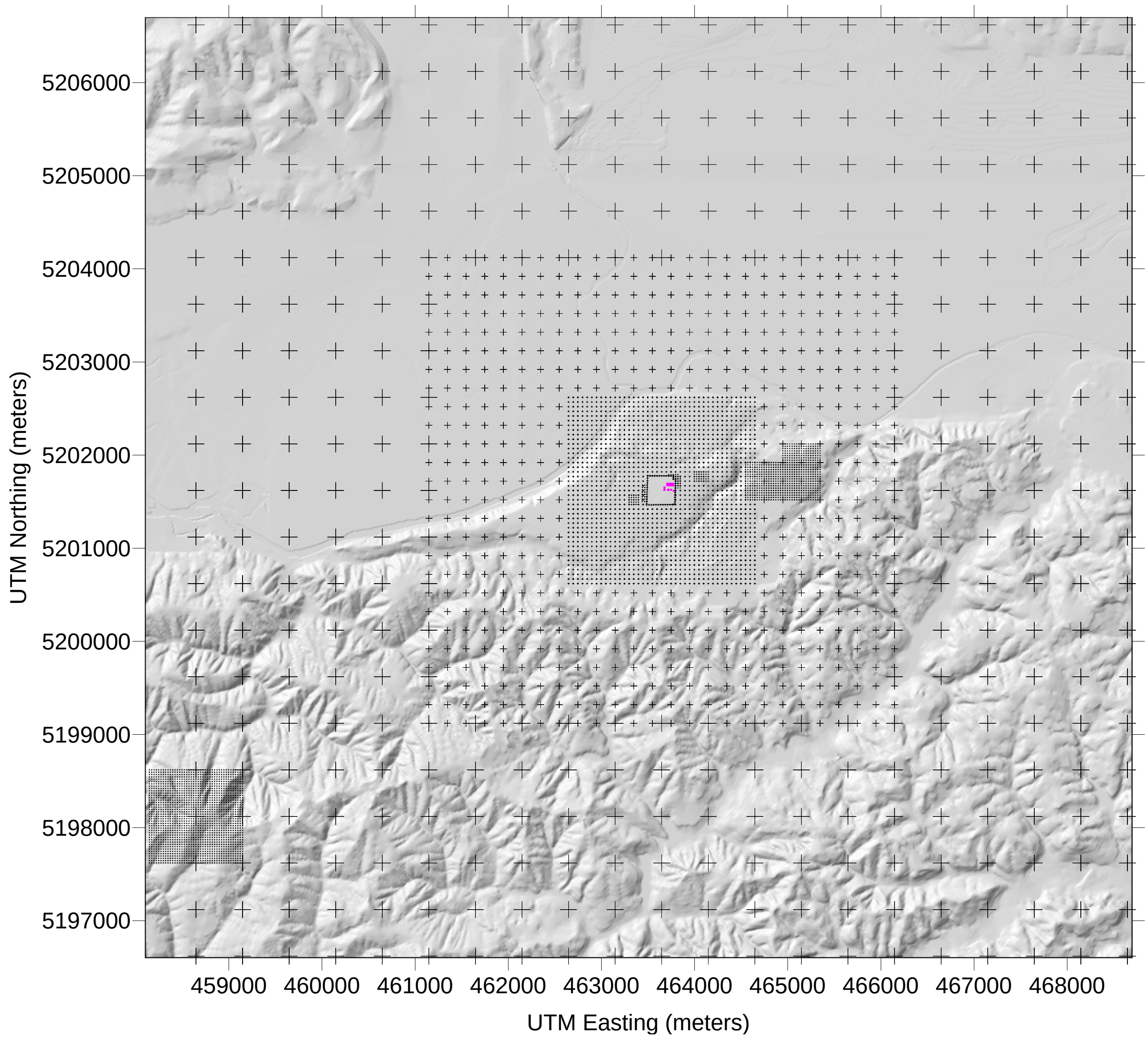


Figure 5.1-1
Receptor Locations

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

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

- Fall 2002 Quarter 3 – from an audit conducted November 19, 2002

- Spring 2003 Quarter 4 – from an audit conducted May 28 and 29, 2003

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

TABLE 5.1-16
SATSOP METEOROLOGICAL SITE DATA RECOVERY SUMMARY

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

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

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

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

Upper Air

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

Land Use Processing

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

AERMET Processing

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

---

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

5.1.3.5 Existing Air Quality

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

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

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

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

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

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

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

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

- $PM_{2.5}$ was monitored in Aberdeen and Oakville, both approximately 16 miles from the project site, where the average of the 98th percentile 24-hour concentration over 2007 and 2008 was 49 percent of the 24-hour NAAQS at both locations. The annual averages at Aberdeen and Oakville were 45 and 41 percent of the NAAQS, respectively.[6]

TABLE 5.1-17
AMBIENT AIR QUALITY MONITORING DATA

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

a. From USEPA AIRS database (http://www.epa.gov/air/data/info.html) and Washington Dept. of Ecology website (https://fortress.wa.gov/ecy/enviwa/), both accessed February 2009. PM_{10} and some SO_2 data from monitoring conducted at the Grays Harbor Energy Center site between May 2002 and May 2003.

b. Data sources are as follows:

a – Seattle, WA (4103 Beacon Hill S)

b – Anacortes, WA (Casino Drive/North End Site)

c1 – Grays Harbor Energy Site, Station 1, May 2002 – May 2003

c2 – Grays Harbor Energy Site, Station 2, May 2002 – May 2003

d – Yelm, WA (709 Mill Rd Se for 2005 data, 931 Northern Pacific Road for 2006-2008 data)

e – Aberdeen, WA (359 N Division St)

f – Oakville, WA (252 Howanut Dr)

c. The data for PM10 and some SO2 from monitoring locations c1 and c2 on the Gray Harbor Energy Center site are from the monitoring period between May 2002 and May 2003.

d. The most stringent standard from NAAQS and WAAQS.

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

f. $PM_{2.5}$ 24-hour average is based on the 98th percentile; the annual standard is based on a three year average.

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

5.1.3.6 Emission Source Release Parameters

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

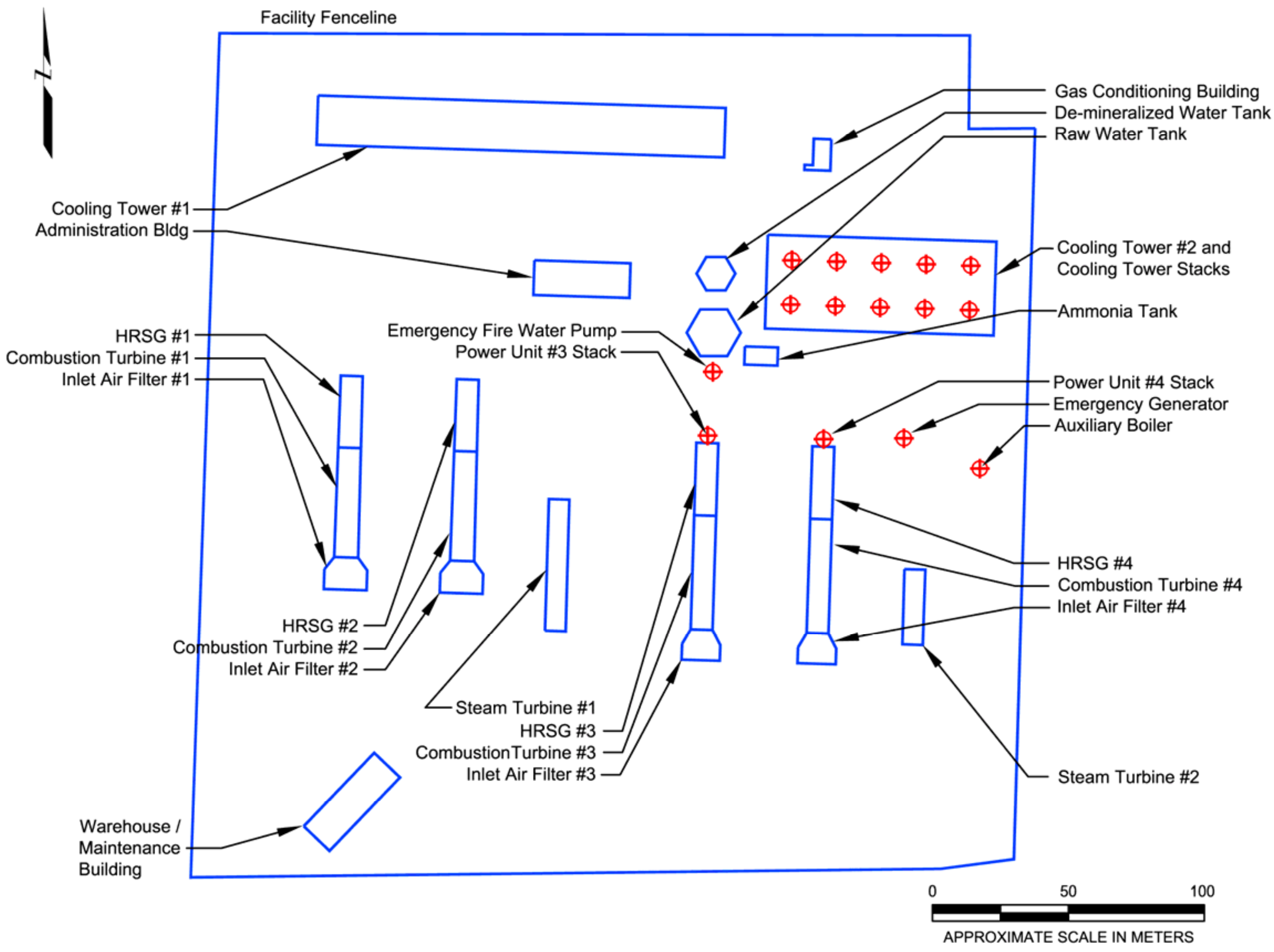


Figure 5.1-2
Emission Sources and Significant Structures Included in the Modeling Simulations

TABLE 5.1-18
POINT SOURCE RELEASE PARAMETERS

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

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

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

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

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

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

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

5.1.3.7 Project Air Quality Impact Analysis Results

To evaluate the potential ambient air pollutant concentrations (i.e., impacts on air quality) attributable to Units 3 and 4, the emission rates associated with operating scenarios described in Section 5.1.2.1 were applied in the dispersion modeling analyses.[7] Note that this subsection

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

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

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

Table 5.1-20 compares maximum concentrations predicted by the model simulations with the applicable Significant Monitoring Concentrations (SMCs) and the Significant Impact Levels (SILs) established in WAC 173-400-113(3). SMCs are thresholds that indicate whether pre-construction monitoring of background air quality is appropriate. The SILs represent incremental, project-specific impact levels that the State of Washington accepts as insignificant with respect to maintaining compliance with the NAAQS, WAAQS, and PSD increments.

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

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

a. Maximum from all operating scenarios, ambient conditions, and turbine types provided by GE Energy.
b. SIL = Significant Impact Level, from WAC 173-400-113(3) except as noted.
c. SMCs and SILs for PM2.5 have been proposed but have not been promulgated

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

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

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

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

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

5.1.3.8 Ambient Standard Analysis

Although SILs have not been promulgated for $PM_{2.5}$, it may be appropriate to evaluate total $PM_{2.5}$ concntrations. If the maximum average background concentration (17.1 μg/m^3, see Table 5.1-17) is added to the maximum predicted concentration (2.71 μg/m^3), the total concentration of 19.8 μg/m^3 compares favorably with the $PM_{2.5}$ ambient air quality standard (35 μg/m^3). After additional rulemaking has occurred, an analysis of PSD Class II increments will be required, but the major and minor source baseline dates have not been set for $PM_{2.5}$, making it impossible to determine which existing sources consume increment.

5.1.3.9 Startup Analysis

To demonstrate that ambient air quality standards will not be exceeded during startup, model simulations were developed for the short-term startup scenario emission rates described in Section 5.1.2.2. AERMOD was applied using the methodology developed for the normal operating scenario simulations and all stack parameters for the combustion turbines. CO is the only criteria pollutant with a short-term standard expected to increase during startup. As shown in Table 5.1-12, NO_x is the only criteria pollutant with an annual standard for which emissions associated with a worst-case annual startup and shutdown scenario would exceed those of worst-case continuous operation. Table 5.1-22 presents a summary of the results of the startup simulations, and indicates that none of the applicable ambient standards would be exceeded as a result of startup or shutdown.

TABLE 5.1-22
MAXIMUM PREDICTED STARTUP ANALYSIS CRITERIA POLLUTANT CONCENTRATIONS
($\mu g/m^3$)

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

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

5.1.3.10 Regional Ozone Analysis

40 CFR 52.21(i)(5)(i) requires any net emissions increase of 100 tpy or more of VOC or NO_x subject to PSD to perform an ambient ozone impact analysis. Table 5.1-13 indicates potential annual emissions of NO_x and VOCs exceed 100 tpy. An ozone impact analysis that includes all post-project emissions is presented in Appendix A-4.

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

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

The largest increase in 8-hour ozone concentration near a Class I area is about 0.01 ppb near Mount Hood Wilderness Area. This is less than 1 percent of the relevant NAAQS, indicating that the facility will not cause or significantly contribute to degradation of natural wild areas. The largest increase in 8-hour ozone concentration near the Enumclaw (Mud Mountain) observation site is less than 0.0004 ppb.

5.1.4 REGIONAL AIR QUALITY IMPACT ASSESSMENT

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

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

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

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

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

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

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

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

5.1.4.1 Assessment of Air Quality Related Values for Class I Areas

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

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

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

Model Selection

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

Potential impacts to AQRVs of concern were assessed using Version 5.8 of the CALPUFF modeling system; the release date of the versions used is June 23, 2007. The CALPUFF modeling system is comprised of three main components: the CALPUFF dispersion model, the CALMET meteorological pre-processor, and the CALPOST post-processor. A number of other utilities provided with the system were also applied to aid in the preparation of the meteorological/geophysical data and to manipulate the large CALPUFF output files.

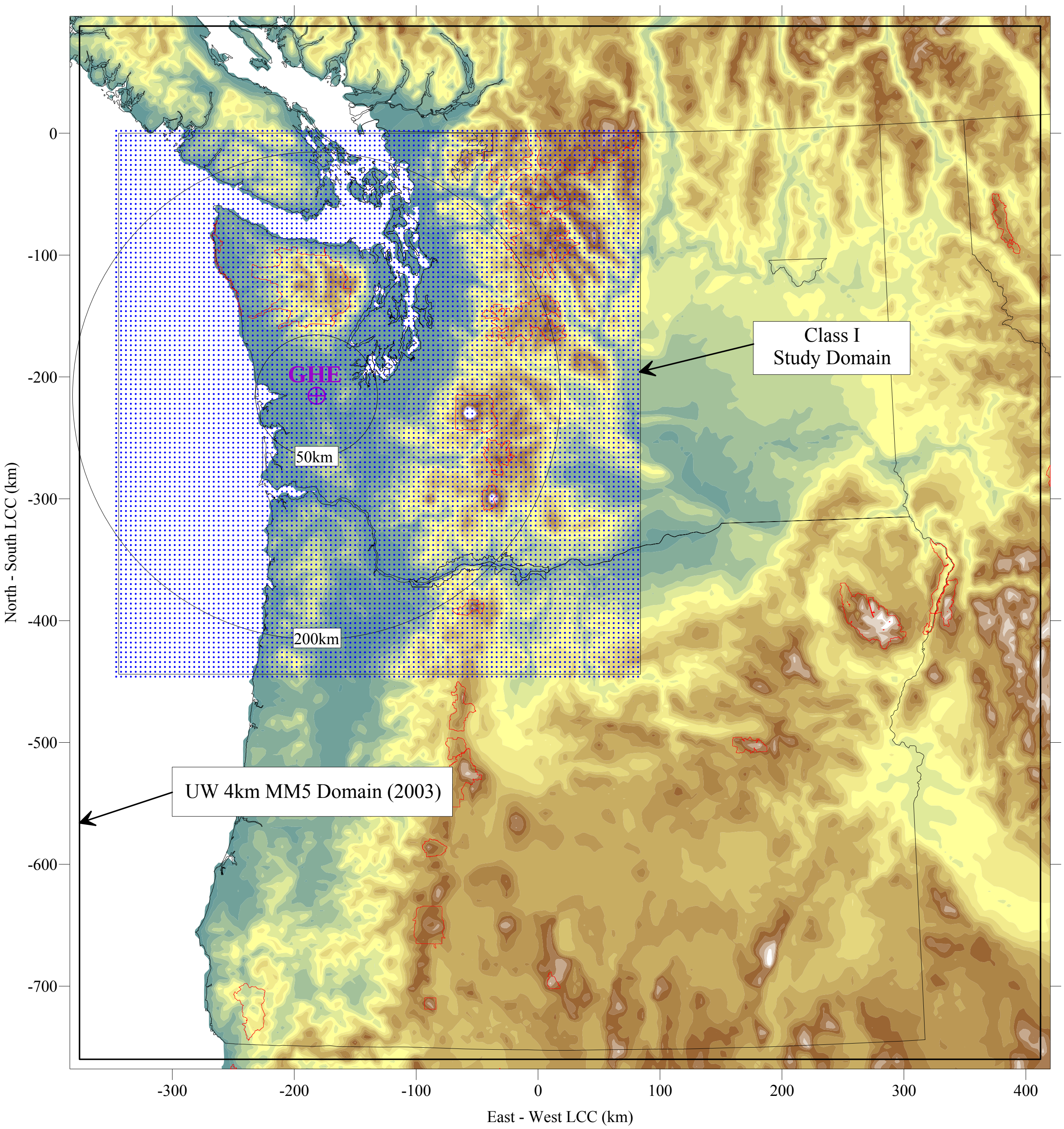


Figure 5.1-3
Modeling Domain for AQRV Analysis

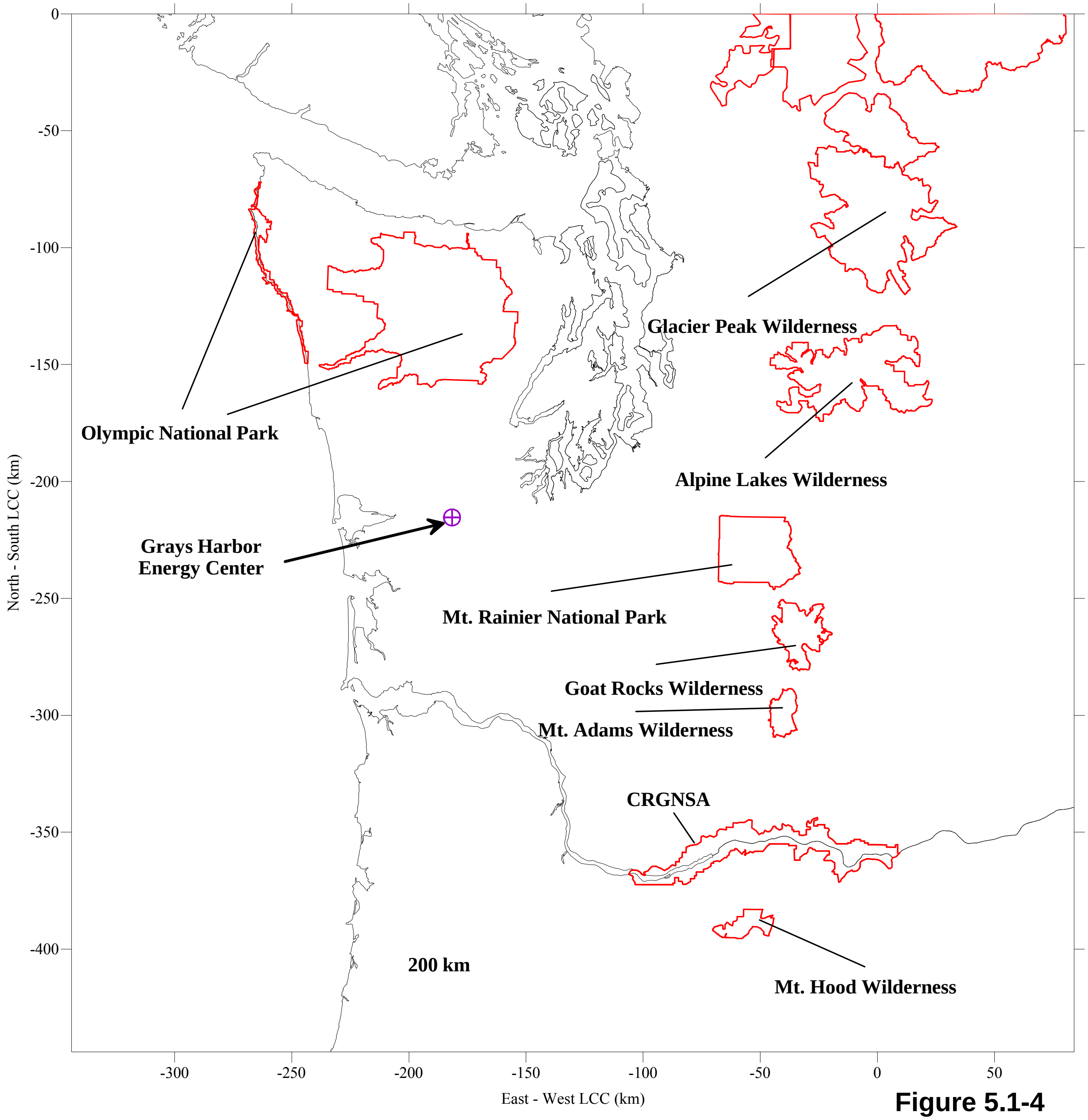


Figure 5.1-4
Locations of Class I Areas and the CRGNSA within the AQRV Modeling Domain

TABLE 5.1-23
CLASS I AREA DISTANCES FROM PROPOSED PROJECT SITE

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

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

CALPUFF Modeling Domain

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

CALPUFF Modeling Procedures

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

Emission Rates and PM_{10} Speciation

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

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

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

a. Speciation based on NPS recommendations for gas-fired turbines where 25% of the PM_{10} is assumed to be filterable and consist of elemental carbon (EC) or soot. The condensable fraction is assumed to consist of ammonium sulfate ($(NH_4)_2SO_4$) from one third conversion of SO_2 and the remainder is organic carbon (OC).

b. SO2 emissions were reduced to account for the amount of sulfur converted (one third) to ammonium sulfate.

c. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 10600602.

d. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 20100102.

e. All PM10 was assumed to consist of fine crustal mass (PMF).

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

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

a. Speciation based on NPS recommendations for gas-fired turbines where 25% of the PM10 is assumed to be filterable and consist of elemental carbon (EC) or soot. The condensable fraction is assumed to consist of ammonium sulfate ((NH4)2SO4) from one third conversion of SO2 and the remainder is organic carbon (OC).

b. SO2 emissions were reduced to account for the amount of sulfur converted (one third) to ammonium sulfate.

c. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 10600602.

d. All PM10 was assumed to be PM2.5. PM2.5 speciation was based on CMAQ profiles for SCC code 20100102.

e. All PM10 was assumed to consist of fine crustal mass (PMF).

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

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

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

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

---

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

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

TABLE 5.1-26
CALPUFF RELEASE PARAMETERS FOR AQRV ANALYSIS

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

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

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

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

Ammonia and Ozone Background Concentrations

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

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

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

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

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

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

Meteorological Data

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

CALMET (Version 5.8), the meteorological preprocessor component of the CALPUFF system, was used to combine the MM5 simulation data, surface observations, terrain elevations, and land use data into the format required by the dispersion modeling component CALPUFF. In addition to specifying the three-dimensional wind field, CALMET also estimates the boundary layer parameters used to characterize diffusion and deposition by the dispersion model.

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

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

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

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

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

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

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

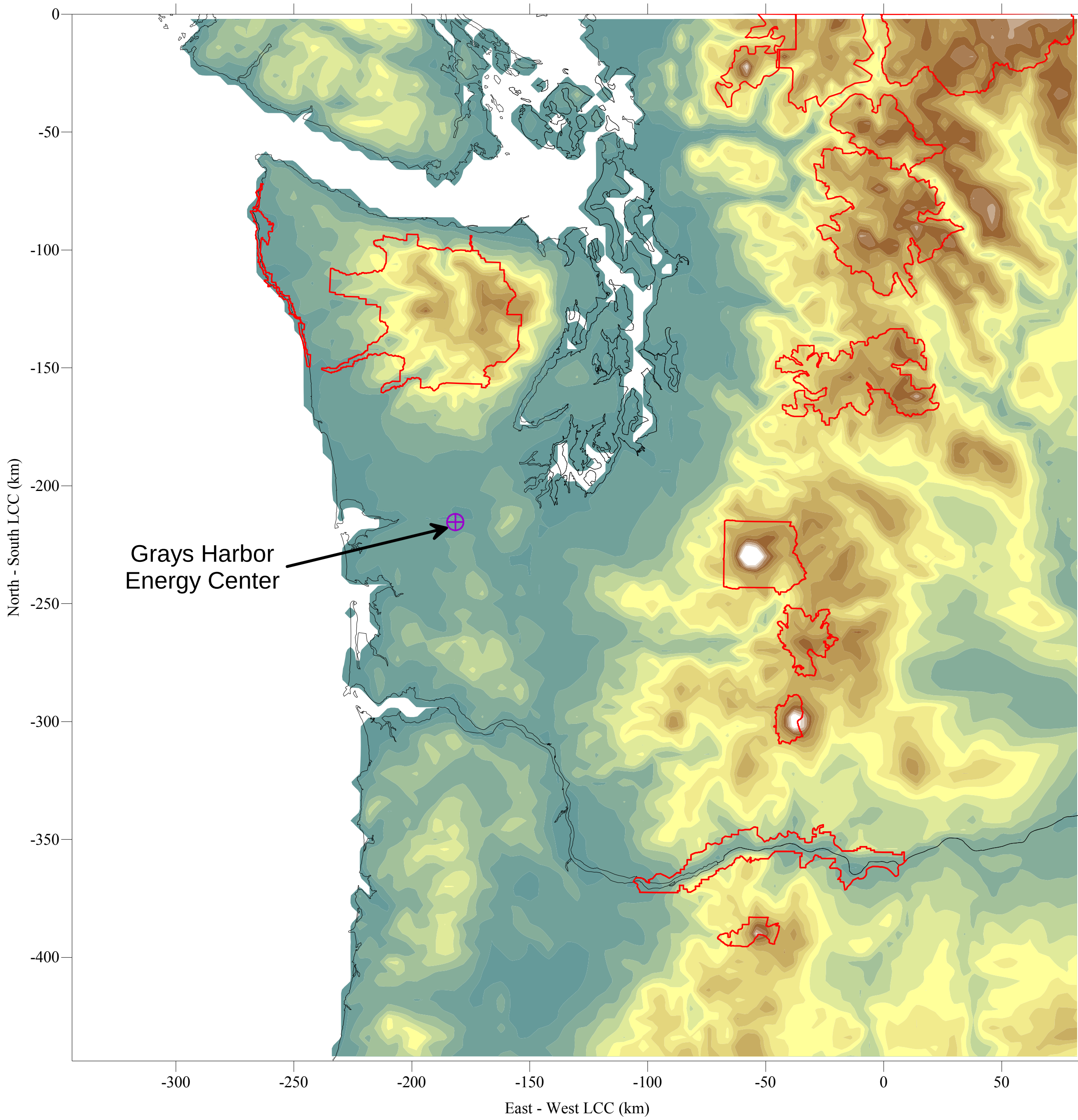


Figure 5.1-5
CALMET 4-km Mesh Size Terrain

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

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

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

Elevation Data and Receptor Network

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

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

AQRV Calculation Procedures

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

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

---

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

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

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

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

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

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

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

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

AQRV Modeling Results

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

Criteria Pollutant Concentrations

Table 5.1-29 summarizes the predicted maximum criteria pollutant concentrations and compares them to the Class I SILs[12] and the Class I PSD increments. Concentrations lower than the SILs indicate insignificant consumption of the Class I increment. Such concentrations are also much lower than pollutant levels thought to adversely affect vegetation (Peterson et al. 1992). As shown in Table 5.1-29, the CALPUFF simulations indicate criteria pollutant concentrations attributable to Unit 3, Unit 4 and associated sources are less than the Class I SILs and the increments in all Class I areas and the CRGNSA.

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

[12] Currently there are two sets of Class I SILs, those proposed by USEPA and those recommended by the FLMs. These proposed and recommended SILs were obtained from the Federal Register, Vol. 61, No. 143, p. 38292, July 23, 1996.

TABLE 5.1-29
PREDICTED CLASS I AREA AND CRGNSA CRITERIA POLLUTANT CONCENTRATIONS
($\mu g/m^3$)

Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes WA	0.0004	0.0392	0.0023	0.0205	0.0068	0.0003
Glacier Peak WA	0.0001	0.0199	0.0012	0.0089	0.0031	0.0001
Goat Rocks WA	0.0002	0.0238	0.0013	0.0185	0.0055	0.0001
Mt. Adams WA	0.0001	0.0146	0.0009	0.0175	0.0033	0.0001
Mt. Hood WA	0.0000	0.0244	0.0006	0.0060	0.0031	0.0001
Mt. Rainier NP	0.0006	0.0619	0.0029	0.0291	0.0099	0.0004
Olympic NP	0.0018	0.1074	0.0044	0.1596	0.0313	0.0007
Columbia River Gorge [b]	0.0002	0.0287	0.0012	0.0145	0.0048	0.0001
Class I Area Max. Conc. [b]	0.0018	0.1074	0.0044	0.1596	0.0313	0.0007
USEPA Proposed SIL[c]	0.1	0.3	0.2	1	0.2	0.1
FLM Recommended SIL[c]	0.03	0.27	0.08	0.48	0.07	0.03
Class I Area PSD Increment[d]	2.5	8	4	25	5	2

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

Table 5.1-30 summarizes the results for the simulations that included emissions for existing Unit 1 and 2 emission units. The predicted cumulative concentrations are about double those attributable to Units 3 and 4, but still much less than the applicable PSD Class I increments. Note the simulations were performed using maximum potential emissions for existing project sources. Since according to regulatory guidance PSD increment consumption from existing sources is based on actual emissions, the results shown in Table 5.1-30 grossly overstate increment consumption attributable to Grays Harbor Energy Center cumulative source emissions.

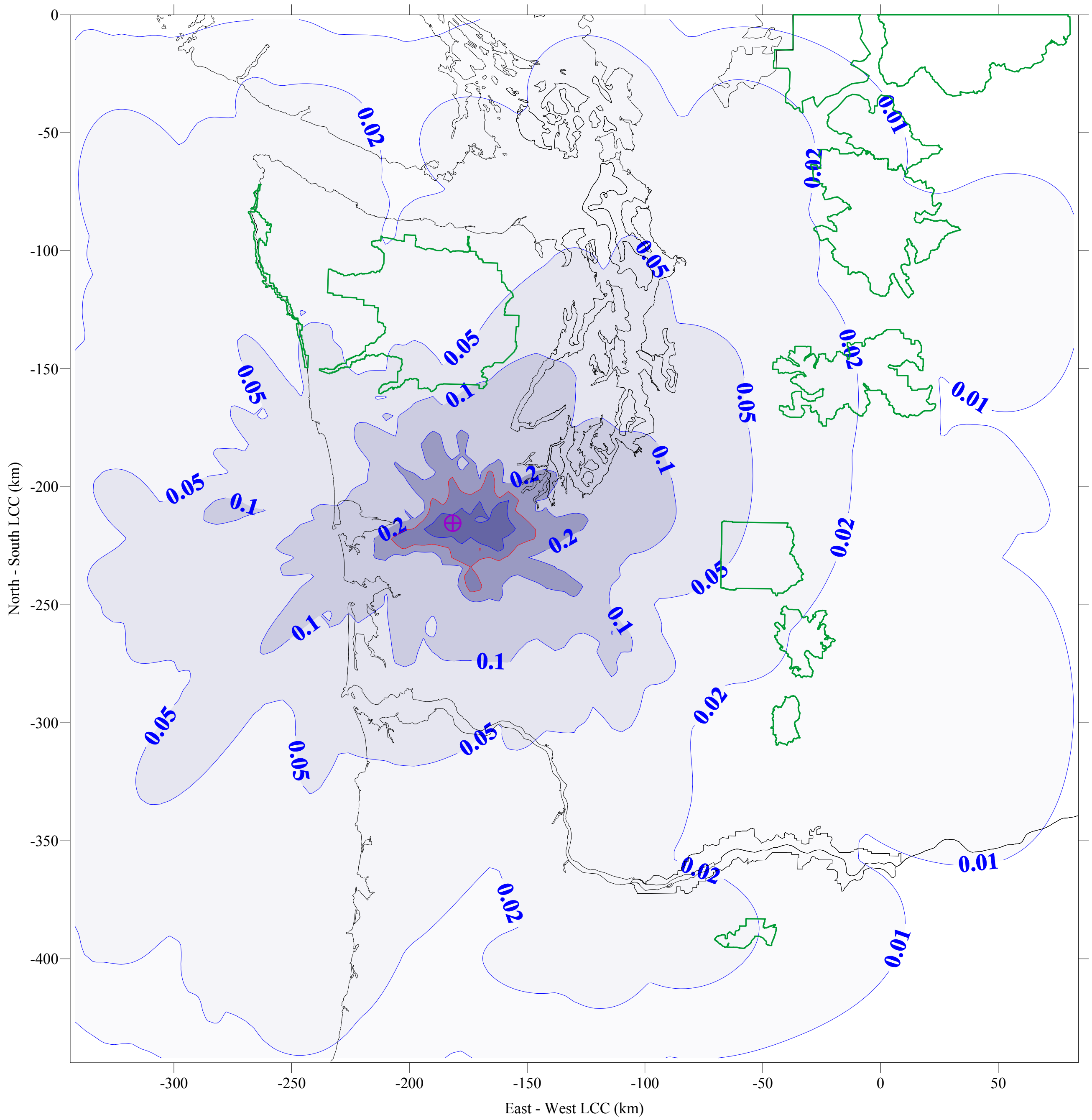


Figure 5.1-6
Maximum Predicted 24-hour PM_{10} Concentrations ($\mu g/m^3$)

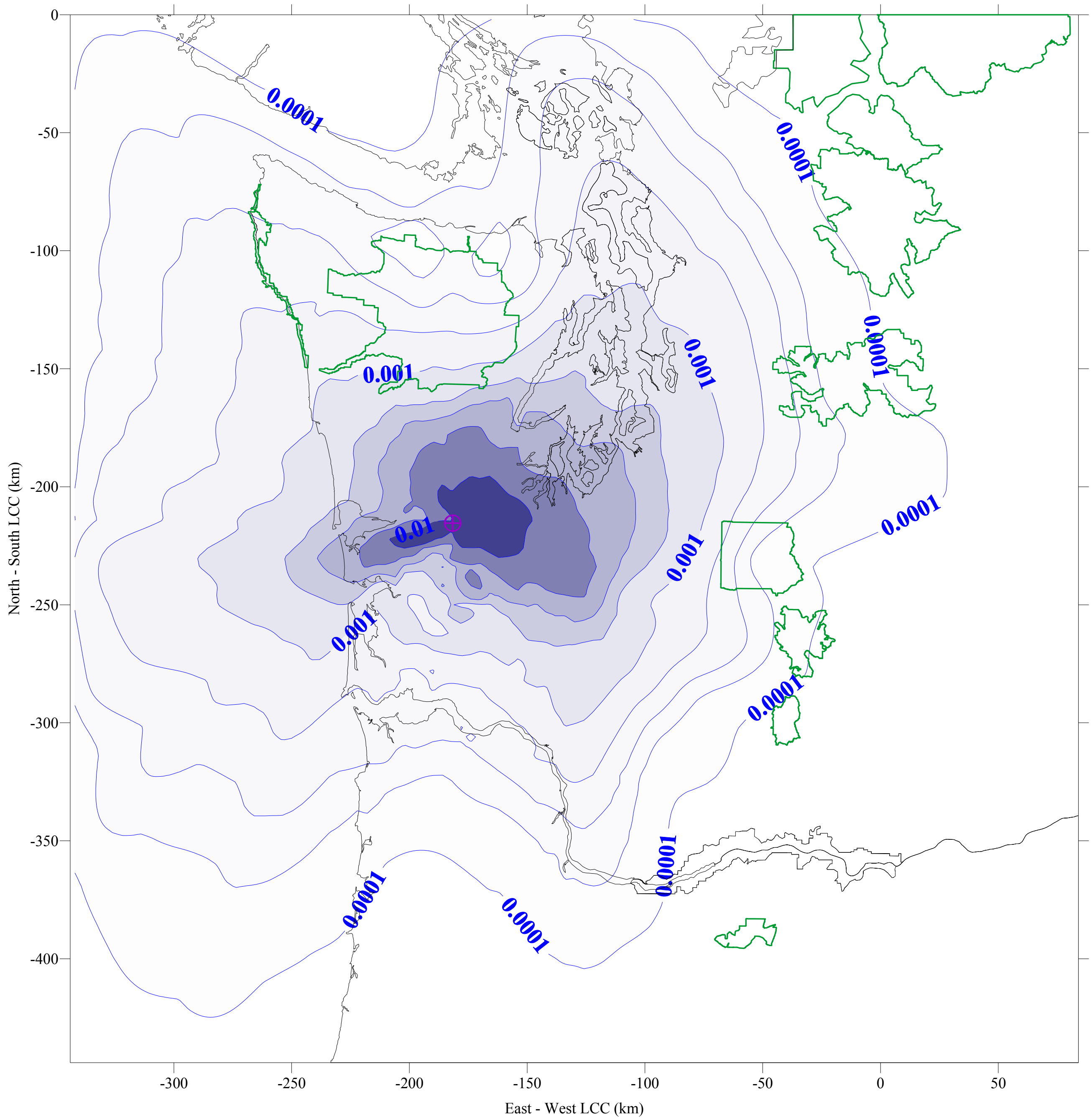


Figure 5.1-7
Maximum Predicted Annual NO_x Concentrations ($\mu g/m^3$)

TABLE 5.1-30
PREDICTED CLASS I AREA AND CRGNSA
CRITERIA POLLUTANT CONCENTRATIONS INCLUDING EXISTING
GRAYS HARBOR ENERGY CENTER SOURCES
($\mu g/m^3$)

Class I and Other Areas of Interest	Maximum Predicted Concentration					
	NO_2[a]	PM_{10}		SO_2		
	Annual Average	24-Hour Average	Annual Average	3-Hour Average	24-Hour Average	Annual Average
Alpine Lakes WA	0.0009	0.0852	0.0052	0.0403	0.0135	0.0006
Glacier Peak WA	0.0003	0.0428	0.0027	0.0175	0.0059	0.0003
Goat Rocks WA	0.0005	0.0508	0.0029	0.0364	0.0111	0.0003
Mt. Adams WA	0.0002	0.0314	0.0019	0.0344	0.0064	0.0002
Mt. Hood WA	0.0001	0.0523	0.0013	0.0117	0.0062	0.0001
Mt. Rainier NP	0.0014	0.1316	0.0064	0.0571	0.0193	0.0008
Olympic NP	0.0042	0.2287	0.0097	0.3151	0.0617	0.0014
Columbia River Gorge [b]	0.0004	0.0617	0.0027	0.0292	0.0096	0.0003
Class I Area Max. Conc.[b]	0.0042	0.2287	0.0097	0.3151	0.0617	0.0014
Class I Area PSD Increment[c]	2.5	8	4	25	5	2

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

Nitrogen and Sulfur Deposition Fluxes

CALPUFF was applied to predict the impacts of acid-forming compounds emitted by the Units 3 and 4 sources on soils, vegetation and aquatic resources in regional Class I areas. There are no standards for evaluation of these impacts to the AQRVs in Washington and Oregon. However, the NPS has established a Deposition Analysis Threshold (DAT) for nitrogen and sulfur of 0.005 kilograms per hectare per year (kg/ha/yr).[13] This threshold is based on natural background deposition values culled from various research efforts, a variability factor, and a safety factor that accounts for cumulative effects. The nitrogen and sulfur DATs are not adverse impact thresholds, but are intended as conservative screening criteria that allow the FLMs to identify potential deposition fluxes that require their consideration on a case-by-case basis.

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

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

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

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

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

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

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

A cumulative analysis of deposition is not required because the predicted deposition fluxes are less than the NPS nitrogen and sulfur DATs. However at the request of the FLMs, Table 5.1-32 shows the predicted deposition rates from the proposed source emissions combined with maximum potential annual emissions from Unit 1 and 2 sources. The cumulative deposition fluxes are also less than the nitrogen and sulfur DATs.

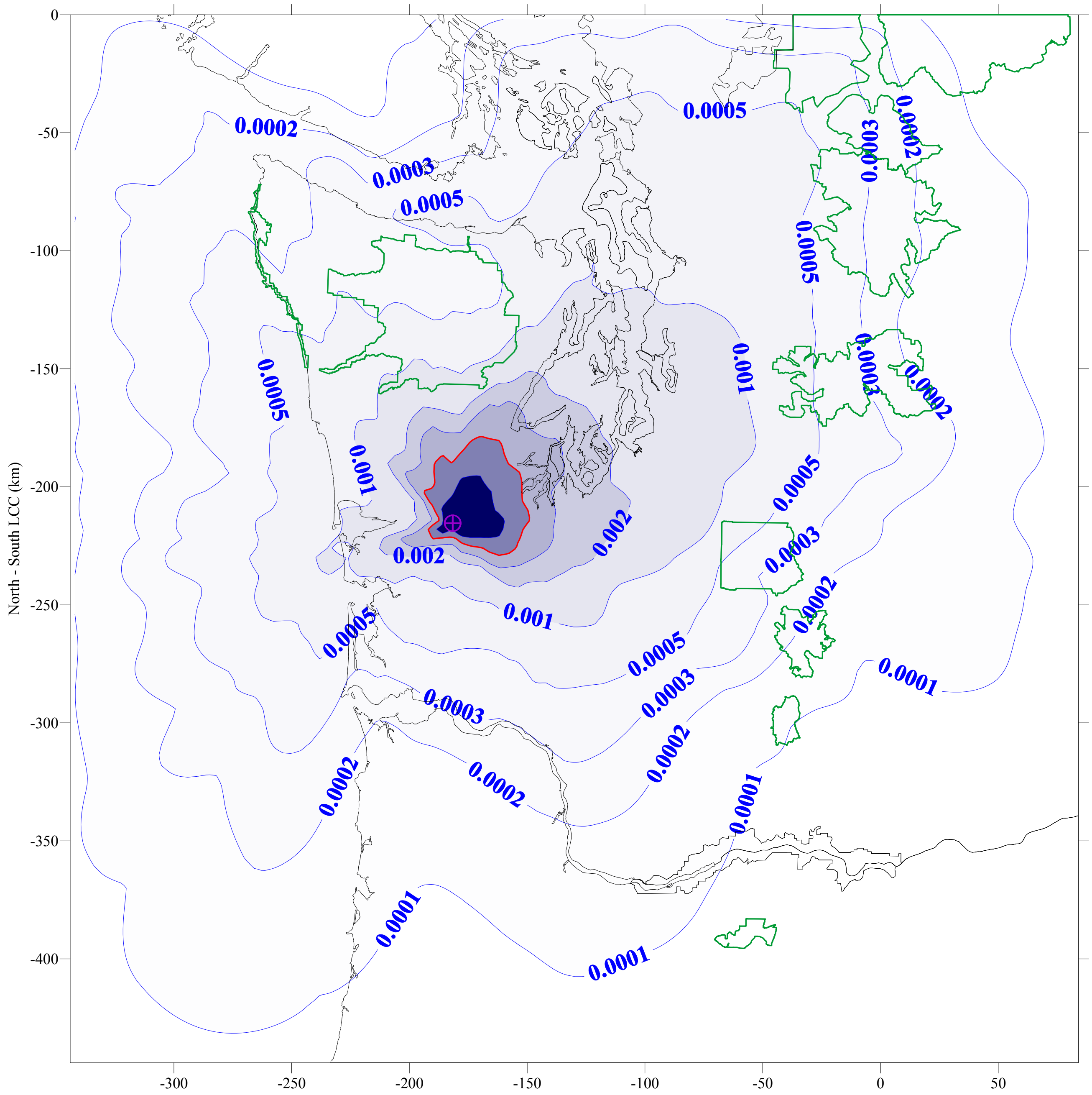


Figure 5.1-8
Maximum Predicted Annual Sulfur Deposition Fluxes (kg/ha/yr)

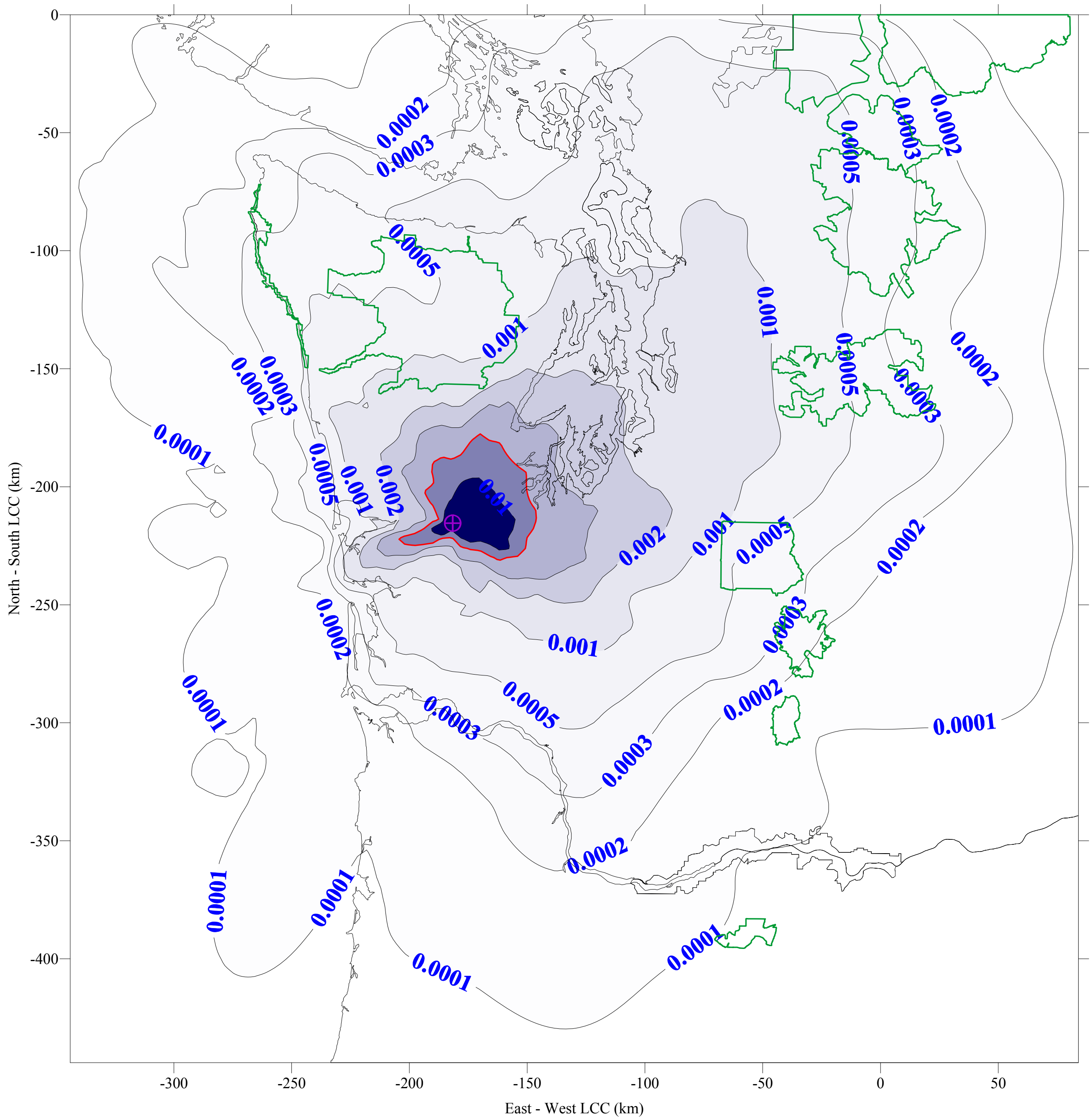


Figure 5.1-9
Maximum Predicted Annual Nitrogen Deposition Fluxes (kg/ha/yr)

TABLE 5.1-32
PREDICTED CLASS I AREA AND CRGNSA DEPOSITION FLUXES INCLUDING EXISTING GRAYS HARBOR ENERGY CENTER SOURCES (kg/ha/yr)

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

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

Regional Haze

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

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

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

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

The ten days with the highest maximum predicted changes in 24-hour extinction in three years using CALPOST Method 2 are identified in Table 5.1-33. Table 5.1-34 lists the highest prediction in each Class I area and in the CRGNSA. The Olympic National Park is the area predicted to have the highest potential changes to background extinction due to the park's close proximity to the source. The other areas of interest are less affected, with occasional higher predictions for Class I areas in western Washington and the CRGNSA. The extinction budgets in Table 5.1-33 and Table 5.1-34 indicate sulfate aerosols followed by nitrate aerosols with high relative humidity contribute to the extinction coefficients on the worst days in Olympic National Park. Many of the higher episodes occur during the winter. For the other Class I areas sulfate, nitrate, and elemental carbon (EC) or soot aerosols dominate the extinction budgets on the worst days.

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

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

TABLE 5.1-33
TEN DAYS WITH MAXIMUM PREDICTED CLASS I AREA AND CRGNSA EXTINCTION CHANGE PREDICTED WITH CALPOST METHOD 2
(1/Mm)

Class I Area and CRGNSA	Date	b_{ext}[a]			Change (%)	F(RH)	b_{ext} by Component[c]					
		Project	Bckgrnd[b]	Total			SO4	NO3	OC	EC	PMC	PMF
Olympic NP	05/08/04	1.982	17.487	19.469	11.33	4.98	1.095	0.607	0.086	0.194	0.000	0.000
Olympic NP	11/22/03	1.462	18.563	20.025	7.88	6.77	0.599	0.665	0.061	0.137	0.000	0.001
Olympic NP	01/17/04	1.473	19.866	21.339	7.42	8.94	0.852	0.404	0.067	0.150	0.000	0.001
Olympic NP	11/21/03	1.207	18.433	19.640	6.55	6.56	0.428	0.578	0.062	0.138	0.000	0.001
Olympic NP	07/22/05	1.051	16.839	17.890	6.24	3.90	0.493	0.384	0.053	0.120	0.000	0.000
Olympic NP	12/18/04	1.171	19.805	20.976	5.91	8.84	0.529	0.498	0.044	0.099	0.000	0.001
Olympic NP	01/07/03	0.893	18.279	19.172	4.88	6.30	0.518	0.221	0.047	0.106	0.000	0.000
Olympic NP	01/28/03	0.924	19.780	20.704	4.67	8.80	0.433	0.367	0.038	0.085	0.000	0.001
Mt. Rainier NP	10/05/03	0.790	17.503	18.293	4.52	5.01	0.342	0.325	0.038	0.085	0.000	0.001
Olympic NP	11/14/03	0.880	20.105	20.985	4.38	9.34	0.468	0.288	0.038	0.086	0.000	0.000

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the current FLAG recommended methods with CALPOST Method 2.

b. Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity.

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

TABLE 5.1-34
MAXIMUM PREDICTED EXTINCTION CHANGE BY CLASS I AREA AND CRGNSA PREDICTED WITH CALPOST METHOD 2
(1/Mm)

Class I Area and CRGNSA	Date	b_{ext} [a]			Change (%)	F(RH)	b_{ext} by Component [c]					
		Project	Bckgrnd [b]	Total			SO4	NO3	OC	EC	PMC	PMF
Alpine Lakes WA	06/24/04	0.714	19.343	20.057	3.69	8.072	0.340	0.290	0.026	0.058	0.000	0.001
Glacier Peak WA	11/22/04	0.358	19.496	19.853	1.84	8.326	0.156	0.160	0.013	0.029	0.000	0.000
Goat Rocks WA	02/28/04	0.282	16.855	17.137	1.67	3.926	0.120	0.123	0.012	0.027	0.000	0.000
Mt. Adams WA	05/18/03	0.147	16.109	16.256	0.91	2.682	0.066	0.048	0.010	0.023	0.000	0.000
Mt. Hood WA	09/17/05	0.227	17.015	17.242	1.34	4.192	0.092	0.103	0.010	0.022	0.000	0.000
Mt. Rainier NP	10/05/03	0.790	17.503	18.293	4.52	5.005	0.342	0.325	0.038	0.085	0.000	0.001
Olympic NP	05/08/04	1.982	17.487	19.469	11.33	4.978	1.095	0.607	0.086	0.194	0.000	0.000
Columbia River Gorge [d]	09/17/05	0.461	17.027	17.488	2.71	4.211	0.190	0.211	0.018	0.041	0.000	0.000

Extinction coefficient in inverse megameters (1/Mm)

a. Grays Harbor Energy Center and background extinction values for daily period that resulted in the maximum percent change in extinction. The extinction coefficients were calculated using the current FLAG recommended methods with CALPOST Method 2.

b. Class I area background extinction derived from default annual average Western U.S. extinction components provided in FLAG guidance document and hourly relative humidity.

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

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

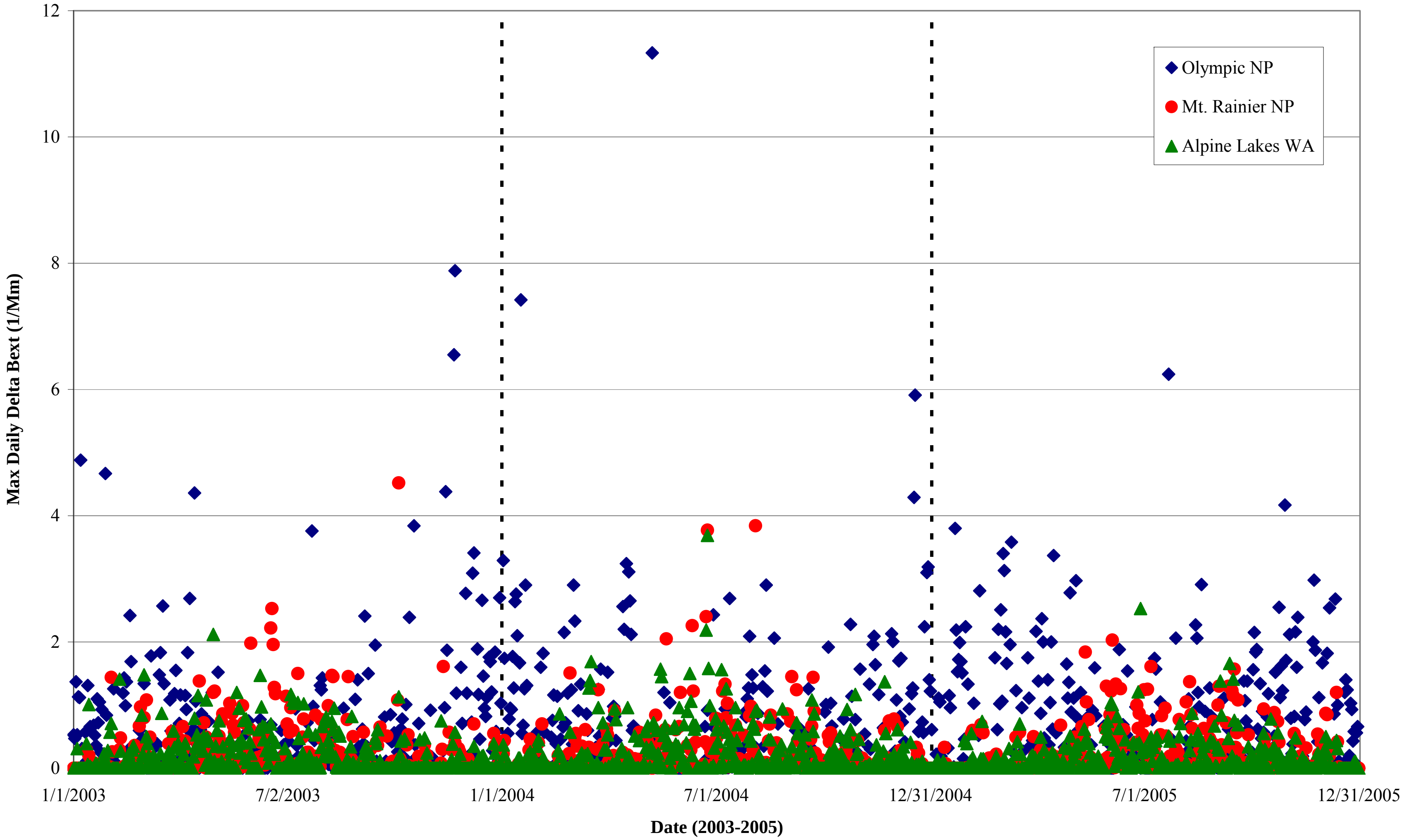


Figure 5.1-10
Time Series of Maximum Daily Change to Extinction for Selected Class I Areas Using CALPOST Method 2

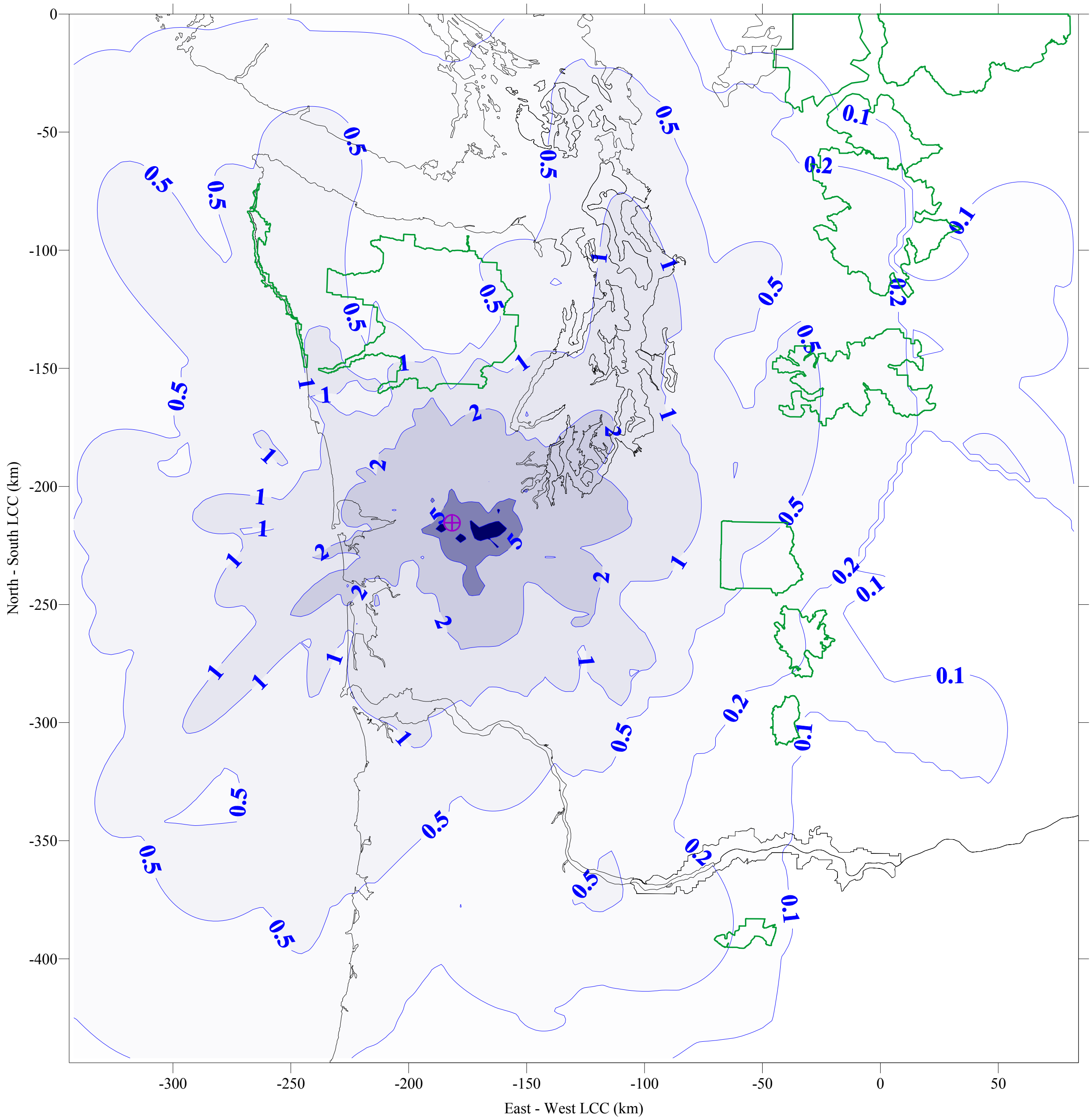


Figure 5.1-11
Maximum Predicted Extinction Coefficient (1/Mm) from/to Grays Harbor Energy Center based on CALPOST Method 2

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

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

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

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

The ten days with the highest predicted changes in 24-hour extinction in three years using CALPOST Method 8 are identified in Table 5.1-35. Table 5.1-36 lists the highest prediction in each Class I area and in the CRGNSA. Using this technique only two days in the three year simulations are greater than the five percent change to extinction criterion. The maximum predicted extinction due to the Unit 3 and 4 sources and the change to background extinction are lower than with CALPOST Method 2.

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

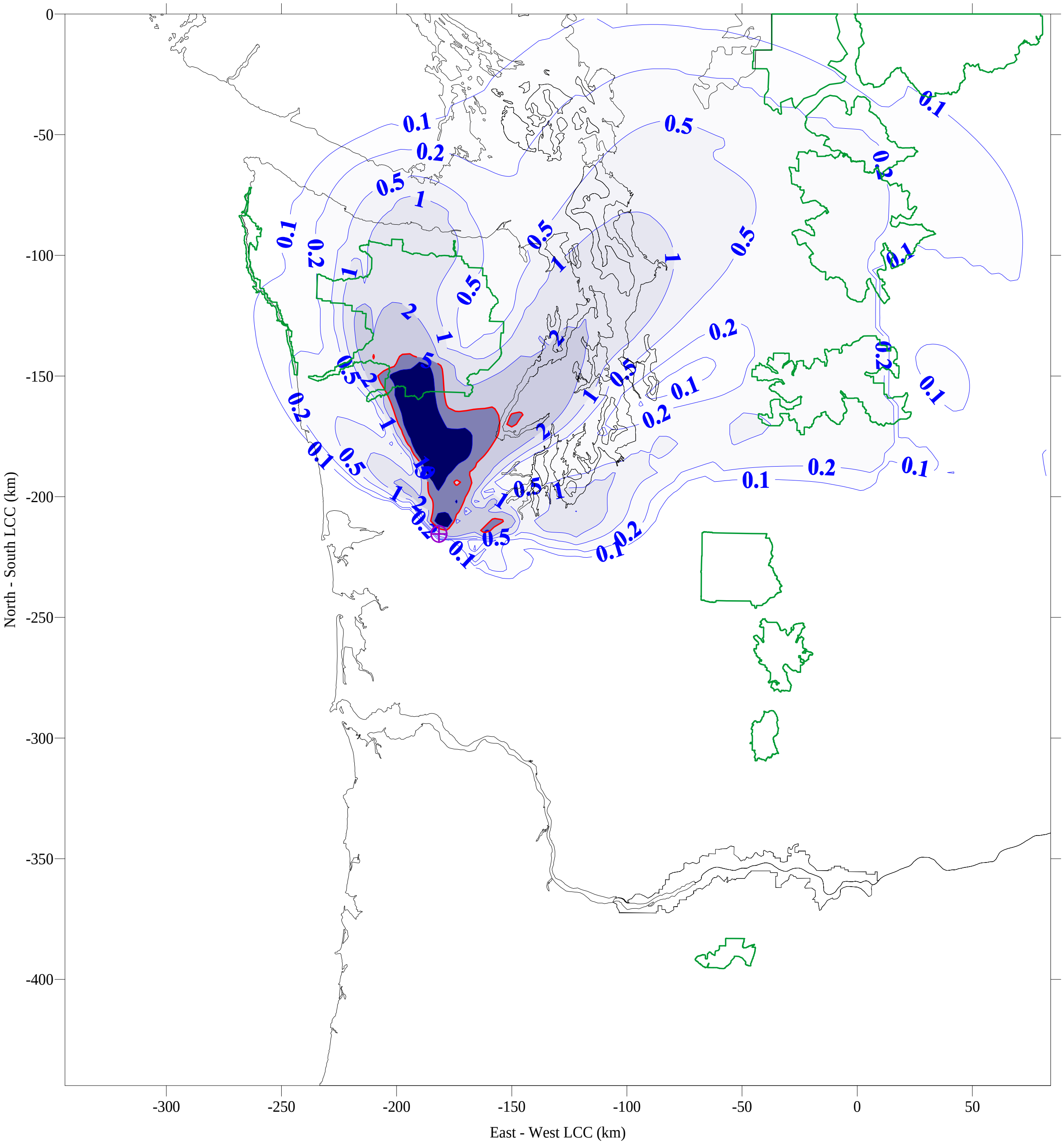


Figure 5.1-12
Predicted Change to the Extinction Coefficient (%) on May 8, 2004 based on CALPOST Method 2

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

Area [d]	Date	b_{ext} [a]			Delta b_{ext}	b_{ext} by Component [c]							F(RH) [b]		
		Project	Back-grnd [b]	Total	(%)	SO_4	NO_3	OC	EC	PMC	PMF	NO_2	Small	Large	Salt
olna	11/21/03	1.278	18.615	19.894	6.87	0.440	0.652	0.046	0.138	0.000	0.001	0.000	6.11	3.99	5.51
olna	11/22/03	1.143	18.615	19.758	6.14	0.417	0.539	0.046	0.137	0.000	0.001	0.003	6.11	3.99	5.51
olna	05/08/04	0.781	17.081	17.862	4.57	0.316	0.190	0.065	0.194	0.000	0.000	0.017	3.81	2.76	3.94
olna	01/17/04	0.796	18.381	19.178	4.33	0.382	0.200	0.050	0.151	0.000	0.001	0.011	5.76	3.80	5.27
olna	12/18/04	0.692	18.558	19.250	3.73	0.274	0.282	0.033	0.099	0.000	0.001	0.004	6.02	3.95	5.46
mora	10/05/03	0.666	17.946	18.612	3.71	0.278	0.274	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	07/23/03	0.622	16.892	17.514	3.68	0.225	0.213	0.045	0.135	0.000	0.001	0.003	3.52	2.61	3.76
olna	03/02/04	0.651	17.745	18.396	3.67	0.233	0.293	0.031	0.092	0.000	0.001	0.001	4.81	3.30	4.61
olna	01/28/03	0.594	18.381	18.976	3.23	0.241	0.235	0.029	0.085	0.000	0.001	0.003	5.76	3.80	5.27
olna	04/14/03	0.556	17.636	18.192	3.15	0.250	0.131	0.041	0.124	0.000	0.001	0.009	4.64	3.21	4.51

Extinction coefficient in inverse megameters (1/Mm)

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

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

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

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

TABLE 5.1-36
MAXIMUM PREDICTED EXTINCTION CHANGE BY CLASS I AREA AND CRGNSA PREDICTED WITH CALPOST METHOD 8
(1/Mm)

d	Date	b_{ext}[a]			Delta b_{ext}	b_{ext} by Component[c]							F(RH)[b]		
		Project	Back-grnd[b]	Total	(%)	SO_4	NO_3	OC	EC	PMC	PMF	NO_2	Small	Large	Salt
alla	10/05/03	0.387	17.201	17.587	2.25	0.158	0.163	0.016	0.049	0.000	0.000	0.000	5.43	3.60	4.98
glpe	11/22/04	0.220	16.904	17.124	1.30	0.085	0.096	0.010	0.029	0.000	0.000	0.000	5.80	3.83	5.31
goro	10/05/03	0.245	15.791	16.036	1.55	0.103	0.099	0.011	0.032	0.000	0.000	0.000	5.22	3.49	4.83
moad	02/27/03	0.146	15.676	15.822	0.93	0.050	0.071	0.006	0.019	0.000	0.000	0.000	5.00	3.40	4.74
moho	09/26/04	0.192	15.415	15.607	1.25	0.074	0.071	0.012	0.036	0.000	0.000	0.000	3.79	2.72	3.78
mora	10/05/03	0.666	17.946	18.612	3.71	0.278	0.274	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	11/21/03	1.278	18.615	19.894	6.87	0.440	0.652	0.046	0.138	0.000	0.001	0.000	6.11	3.99	5.51
xcrg	10/02/03	0.240	16.065	16.306	1.50	0.089	0.103	0.012	0.036	0.000	0.000	0.000	4.93	3.35	4.67

Extinction coefficient in inverse megameters (1/Mm)

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

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

c. Extinction coefficient components are: SO4 = sulfate, NO3 = nitrate, OC = organic carbon, EC = elemental carbon, PMC = coarse mass, PMF = crustal mass, NOx = nitrogen dioxide.

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

Table 5.1-37 shows the number of days exceeding the five percentile change to extinction criterion by year, Class I area, and calculation method due to emissions from Unit 3 and 4 sources. The highest 98th percentile change to extinction of 2.8 percent predicted for Olympic National Park in 2003 is less than the five percent screening criterion. Based on the current modeling simulations and methods from the 2008 proposed revisions to the FLAG Phase I report, emissions from Unit 3 and 4 sources would not significantly degrade visibility in Class I areas.

Although a cumulative visibility analysis is not required based on the analysis above, at the request of the FLMs extinction coefficients were also calculated from simulations that included emissions from existing Unit 1 and 2 sources. The resulting ten days with the highest maximum predicted changes in 24-hour extinction in three years using CALPOST Method 8 are identified in Table 5.1-38. Table 5.1-39 shows the 98th percentile change to extinction and the number of days per year exceeding a five percent change to extinction. For cumulative Grays Harbor Energy Center sources, 20 days in three years were predicted to have a greater than five percent change to natural background extinction in the Olympic National Park. The highest yearly 98th percentile change to the 24-hour extinction coefficient was 5.8 percent.

5.1.5 ADDITIONAL IMPACT ANALYSIS

5.1.5.1 Class II Area Growth

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

Units 3 and 4 would consume natural gas delivered by pipeline. Its product, electricity, would be delivered by electrical transmission lines. Consequently, the facility will not require a large workforce to provide raw materials to the facility or to transport product from the facility. Operation of the facility will require a work force of approximately 31 people. Grays Harbor Energy does not expect Units 3 and 4 to cause significant population growth in the area nor significant secondary air quality impacts as a result of that growth.

TABLE 5.1-37
PREDICTED 98TH PERCENTILE AND NUMBER OF DAYS WITH EXTINCTION CHANGE GREATER THAN FIVE PERCENT BY AREA, YEAR, AND CALCULATION METHOD

Class I Area and CRGNSA	Year	Extinction Calculated by CALPOST Method 2		Extinction Calculated by CALPOST Method 8	
		98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext}> 5%	98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext}> 5%
Alpine Lakes WA	2003	1.13	0	0.79	0
	2004	1.45	0	0.82	0
	2005	0.87	0	0.66	0
Glacier Peak WA	2003	0.47	0	0.41	0
	2004	0.75	0	0.53	0
	2005	0.47	0	0.38	0
Goat Rocks WA	2003	0.91	0	0.64	0
	2004	0.74	0	0.60	0
	2005	0.72	0	0.64	0
Mt. Adams WA	2003	0.44	0	0.41	0
	2004	0.47	0	0.36	0
	2005	0.44	0	0.47	0
Mt. Hood WA	2003	0.38	0	0.35	0
	2004	0.58	0	0.42	0
	2005	0.40	0	0.33	0
Mt. Rainier NP	2003	1.47	0	1.03	0
	2004	1.44	0	0.90	0
	2005	1.30	0	1.18	0
Olympic NP	2003	3.76	2	2.81	2
	2004	3.11	3	2.28	0
	2005	2.98	1	2.25	0
Columbia River Gorge	2003	0.71	0	0.62	0
	2004	1.07	0	0.76	0
	2005	0.74	0	0.70	0

TABLE 5.1-38
MAXIMUM PREDICTED EXTINCTION CHANGE BY CLASS I AREA AND CRGNSA
PREDICTED WITH CALPOST METHOD 8 INCLUDING GRAYS HARBOR ENERGY CENTER EXISTING SOURCES
(1/Mm)

Area [d]	Date	b_{ext} [a]			Delta b_{ext} (%)	b_{ext} by Component [c]							F(RH) [b]		
		Project	Back-grnd [b]	Total		SO4	NO3	OC	EC	PMC	PMF	NO2	Small	Large	Salt
alla	10/05/03	0.387	17.201	17.587	2.25	0.158	0.163	0.016	0.049	0.000	0.000	0.000	5.43	3.60	4.98
glpe	11/22/04	0.220	16.904	17.124	1.30	0.085	0.096	0.010	0.029	0.000	0.000	0.000	5.80	3.83	5.31
goro	10/05/03	0.245	15.791	16.036	1.55	0.103	0.099	0.011	0.032	0.000	0.000	0.000	5.22	3.49	4.83
moad	02/27/03	0.146	15.676	15.822	0.93	0.050	0.071	0.006	0.019	0.000	0.000	0.000	5.00	3.40	4.74
moho	09/26/04	0.192	15.415	15.607	1.25	0.074	0.071	0.012	0.036	0.000	0.000	0.000	3.79	2.72	3.78
mora	10/05/03	0.666	17.946	18.612	3.71	0.278	0.274	0.028	0.085	0.000	0.001	0.000	5.55	3.66	5.05
olna	11/21/03	1.278	18.615	19.894	6.87	0.440	0.652	0.046	0.138	0.000	0.001	0.000	6.11	3.99	5.51
xcrg	10/02/03	0.240	16.065	16.306	1.50	0.089	0.103	0.012	0.036	0.000	0.000	0.000	4.93	3.35	4.67

Extinction coefficient in inverse megameters (1/Mm)

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

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

c. Extinction coefficient components are: SO4 = sulfate, NO3 = nitrate, OC = organic carbon, EC = elemental carbon, PMC = coarse mass, PMF = crustal mass, NOx = nitrogen dioxide.

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

TABLE 5.1-39
PREDICTED 98TH PERCENTILE AND NUMBER OF DAYS WITH EXTINCTION CHANGE GREATER THAN FIVE PERCENT USING CALPOST METHOD 8 INCLUDING GRAYS HARBOR ENERGY CENTER EXISTING SOURCES

Class I Area and CRGNSA	Year	Extinction Calculated by CALPOST Method 8	
		98th Percentile Delta b_{ext} (%)	No. Days Delta b_{ext}> 5%
Alpine Lakes WA	2003	1.68	0
	2004	1.77	0
	2005	1.41	0
Glacier Peak WA	2003	0.87	0
	2004	1.15	0
	2005	0.80	0
Goat Rocks WA	2003	1.28	0
	2004	1.27	0
	2005	1.34	0
Mt. Adams WA	2003	0.86	0
	2004	0.77	0
	2005	0.99	0
Mt. Hood WA	2003	0.74	0
	2004	0.88	0
	2005	0.76	0
Mt. Rainier NP	2003	2.09	1
	2004	1.91	0
	2005	2.39	0
Olympic NP	2003	5.78	10
	2004	4.68	6
	2005	4.58	3
Columbia River Gorge	2003	1.31	0
	2004	1.59	0
	2005	1.48	0

5.1.5.2 Class II Visibility

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

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

However, Units 3 and 4 will require a ten-cell cooling tower to exhaust waste heat. The cooling tower cells will produce visible water vapor clouds that vary in size depending on meteorology and operational factors. Cooling tower plumes are most visible when the ambient air is nearly saturated with water, when visibility is already poor.

5.1.5.3 Soils and Vegetation

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

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

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

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

Appendix A

Air Quality Appendices

Appendix A-1

BACT Analysis

APPENDIX A-1
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

In Washington, Best Available Control Technology BACT is required for criteria and toxic air pollutant (TAP) emissions from new and modified industrial sources. This Appendix presents a BACT analysis for emission units associated with the Grays Harbor Energy project. The basis for the emissions-related analyses is annual average operation at a nominal design capacity of 530 gross megawatts (MW).

A-1.1 BACT ANALYSIS OVERVIEW AND RESULTS SUMMARY

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

- Two combined-cycle natural gas-fired combustion turbines;
- Two 5-cell, recirculating, mechanical-draft cooling towers for the combined cycle plants;
- One auxiliary boiler; and
- Two diesel-fueled engines for emergency electricity generation and fire water.

Figure 2.3-1 in Section 2.3 (Construction on Site) of this Application provides an illustration of the proposed project indicating the layout of the major plant components within the site.

TABLE A-1-1
PROPOSED BACT FOR GRAYS HARBOR ENERGY CENTER

Pollutant	Control	Emissions Limits
Combustion Turbines (per combustion turbine excluding start up & shutdown).		
NO_x	Selective Catalytic Reduction (SCR)	2 ppmvd @ 15% O_2, 3-hour average
CO	Oxidation Catalyst	2 ppmvd @ 15% O_2 (above 60% load), 3-hour average
PM/PM_{10}	Good Combustion Practices (GCP), Gaseous Fuels only	0.007 lb/MMBtu, 24-hour average
SO_2	Pipeline Natural Gas	None
VOC	GCP	1 ppmvd @ 15% O_2 100% load 3 ppmvd @ 15% O2 60% load
NH_3	Molar ratio control on Injection System	5 ppmvd @ 15% O_2, 20 lb/hr (BACT-based Limit)
H_2SO_4	Pipeline Natural Gas	None
TAPs	GCP, Pipeline Natural Gas	None
Auxiliary Boiler (Natural Gas-Fired, <30 MMBtu/hr heat input)		
NO_x	GCP, Ultra-Low-NO_x burner	0.011 lb/MMBtu @ 3% O_2, approx 9 ppmvd, 3-hr average
CO	GCP	0.037 lb/MMBtu @ 3% O_2, approx 50 ppmvd, 3-hr average
PM/PM_{10}	GCP, Gaseous Fuels Only	None
SO_2	Pipeline Natural Gas	None
VOC	GCP	None
TAPs	GCP, Pipeline Natural Gas	None
Cooling Towers (10ell, Mechanical Draft Type)		
PM/PM_{10}	High Efficiency Mist Eliminators, TDS limit in circulating water	0.0005% draft as percent of circulating water
Diesel Engines		
NO_x	Combustion controls, restricted operating hours	40 CFR Part60, Subpart IIII emission standards for emergency stationary compression ignition internal combustion engines; Operation of each engine limited to ≤ 26hours/year of non-emergency operation; Use of ultra-low-sulfur (15 parts per million of sulfur by weight) diesel fuel.
CO	Combustion controls, restricted operating hours	
PM/PM_{10}	Combustion controls, restricted operating hours, ultra-low-sulfur fuel	
SO_2	Ultra-low-sulfur diesel fuel, restricted operating hours	
VOC	Combustion controls, restricted operating hours	
TAPs	Combustion controls, restricted operating hours, ultra-low-sulfur fuel	

The following sections describe the BACT demonstration process, and the individual control technology evaluations for each emission unit and pollutant subject to BACT-based limits.

A-1.2 BACT REVIEW PROCESS

BACT is defined in the PSD regulations as:

> *"... an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source ... which [is determined to be achievable], on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs" [40 CFR 52.21(b)(12)]*

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

This top-down BACT analysis process can be considered to contain five basic steps described below (from the EPA's Draft New Source Review Workshop Manual, 1990)[1]:

Step 1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;

Step 2. Eliminate all technically infeasible control technologies;

Step 3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy;

Step 4. Evaluate most effective controls and document results; and

Step 5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

Formal use of these steps is not always necessary. However, EPA has consistently interpreted the statutory and regulatory BACT definitions as containing two core requirements, which EPA believes must be met by any BACT determination, irrespective of whether it is conducted in a

---

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

“top-down” manner. First, the BACT analysis must include consideration of the most stringent available technologies: i.e., those that provide the “maximum degree of emissions reduction.” Second, any decision to require a lesser degree of emissions reduction must be justified by an objective analysis of “energy, environmental, and economic impacts” contained in the record of the permit decisions.

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

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

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

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

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

A-1.3 COMBUSTION TURBINE BACT ANALYSIS

The following BACT analysis evaluates control technologies applicable to each of the criteria pollutants that would be emitted from the combustion turbines proposed for Units 3 and 4 to determine appropriate BACT emission limits. This BACT analysis is based on the current state of emissions control technology, energy and environmental factors, current expected economics, energy, and technical feasibility.

A-1.3.1 PROCESS DESCRIPTION

The project will add two natural gas-fired combined cycle (NGCC) combustion turbines. Each combustion turbine will be paired with a HRSG with duct burners. Steam from the two HRSGs will be sent to a single steam turbine that will turn a power generator. Both the combustion turbines as well as the duct burners will be fueled only by pipeline quality natural gas. Pollutant emissions from the NGCC combustion turbine units will include NO_x, PM_{10}, $PM_{2.5}$, CO, SO_2, and VOCs.

A-1.3.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

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

TABLE A-1-2
RECENT BACT DETERMINATIONS FOR NATURAL GAS-FIRED COMBINED-CYCLE COMBUSTION TURBINES

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
FL-0304	09-08-08	Florida Municipal Power Agency	Osceola County, FL	Combined Cycle Gas Turbine	1,860 MMBtu/hr	NO_X – 2 ppmvd CO – 6 ppmvd 10% Opacity	SCR, GCPs, Low Sulfur Fuel	BACT-PSD
FL-0303	07-30-08	Florida Power & Light Co.	Palm Beach County, FL	Combined Cycle Gas Turbines (3)	2,333 MMBtu/hr (each unit)	NO_X – 2 ppmvd CO – 6 ppmvd VOC – 1.2 ppmvd 10% Opacity	LNBs, SCR, GCPs, Low Sulfur Fuel,	BACT-PSD
LA-0224	03-20-08	Southwest Electric Power Company (SWEPCO)	Caddo County, LA	Combined Cycle Gas Turbine	2,110 MMBtu/hr	NO_X – 4 ppmvd@15% O_2 CO – 10 ppmvd @ 15%O_2 VOC – 4.9 ppmvd @ 15%O_2 PM_{10} – 0.011 lb/MMBtu SO_2 – 0.0057 lb/MMBtu	LNBs, SCR, GCPs, Low Sulfur Fuel	BACT-PSD
CT-0151	02-25-08	Kleen Energy Systems, LLC	Middlesex County, CT	Combustion Turbine with Duct Burner	2.1 MMcf/hr	NO_X – 2 ppm @ 15% O_2 CO – 0.9 ppmvd @ 15%O_2 VOC – 5 ppmvd @ 15%O_2 PM_{10} – 0.006 lb/MMBtu SO_2 – 0.0020 lb/MMBtu	LNBs, SCR, Oxidation Catalyst	LAER (NO_X); BACT-PSD
VA-0308	01-14-08	CPV Warren	Warren County, VA	Combined Cycle Gas Turbine with Duct Burner	1,717-2,204 MMBtu/hr	NO_X – 2 ppmvd CO – 1.2 ppmvd VOC – 0.7 ppmvd PM_{10} – 0.013 lb/MMBtu SO_2 – 0.002 lb/MMBtu	LNBs, SCR, GCPs, Oxidation Catalyst	BACT-PSD
GA-0127	01-07-08	Southern Company/ Georgia Power	Cobb County, GA	Combined Cycle Combustion Turbine	254 MW	NO_X – 6 ppmvd @ 15% O_2 CO – 1.8 ppmvd @ 15%O_2 VOC – 1.8 ppmvd @ 15%O_2 PM_{10} – 0.1 lb/MMBtu 20% Opacity	LNBs, SCR, Water Injection, Oxidation Catalyst	LAER (VOC); PSD-BACT

TABLE A-1-2 (Continued)
RECENT BACT DETERMINATIONS FOR NATURAL GAS-FIRED COMBINED-CYCLE COMBUSTION TURBINES

Permit or RBLC ID	Permit Issuance Date	Company	Location	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0071	06-05-07	Minnesota Municipal Power Agency	Rice County, MN	Combined Cycle Combustion Turbine with Duct Burner	1,758 MMBtu/hr	NO_X – 3 ppmvd CO – 9 ppmvd VOC – 3 ppmvd PM_{10} – 0.01 lb/MMBtu	LNBs, SCR, Water Injection, GCPs	BACT-PSD
CA-1144	04-25-07	Caithness Blythe II, LLC	Riverside County, CA	Combined Cycle Combustion Turbine	170 MW	NO_X – 2 ppmvd @ 15% O_2 CO – 4 ppmvd @ 15%O_2	SCR	BACT-PSD
FL-0285	01-26-07	Progress Energy Florida (PEF)	Pinellas County, FL	Combined Cycle Combustion Turbine	1,972 MMBtu/hr	NO_X – 15 ppmvd CO – 8 ppmvd VOC – 1.5 ppmvd @ 15%O_2 10% Opacity	Water Injection, GCPs	BACT-PSD
FL-0286	01-10-07	Florida Power And Light Company	West Palm Beach County, FL	Combined Cycle Combustion Gas Turbine	2,333 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 CO – 8 ppmvd @ 15%O_2 VOC – 1.5 ppmvd @ 15%O_2	LNBs, SCR, Water Injection	BACT-PSD
OK-0115	12-12-06	Energetix	Comanche County, OK	Combustion Turbine And Duct Burner	1,911 MMBtu/hr	NO_X – 3.5 ppmvd @ 15% O_2 CO – 16.4 ppmvd @ 15%O_2 PM_{10} – 0.0067 lb/MMBtu	LNBs, SCR, GCPs	BACT-PSD
NY-0095	05-10-06	Caithness Bellport, LLC	Suffolk County, NY	Combined Cycle Combustion Turbine	2,221 MMBtu/hr	NO_X – 2 ppmvd @ 15% O_2 CO – 2 ppmvd @ 15%O_2 PM_{10} – 0.0067 lb/MMBtu SO_2 – 0.0011 lb/MMBtu	SCR, Oxidation Catalyst, Low Sulfur Fuel	BACT-PSD
CO-0056	05-02-06	Calpine Corp.	Weld County, CO	Combined Cycle Turbine	300 MW	NO_X – 3 ppm @ 15% O_2 CO – 3 ppm @ 15%O_2 VOC – 0.0029 lb/MMBtu PM_{10} – 0.0074 lb/MMBtu 10% Opacity	LNBs, SCR, GCPs, Oxidation Catalyst, Low Sulfur Fuel	BACT-PSD
NC-0101	09-29-05	Forsyth Energy Projects, LLC	Forsyth County, NC	Combined Cycle Turbine	1,844 MMBtu/hr	NO_X – 3 ppm @ 15% O_2 CO – 11.6 ppm @ 15%O_2 VOC – 5.7 ppm @ 15%O_2 PM_{10} – 0.019 lb/MMBtu SO_2 – 0.0006 lb/MMBtu	LNBs, SCR, GCPs, Low Sulfur Fuel	BACT-PSD
NV-0035	08-16-05	Sierra Pacific Power Company	Storey County County, NV	Combined Cycle Combustion Turbine with Duct Burner.	306 MW	NO_X – 2 ppm @ 15% O_2 CO – 3.5 ppm @ 15%O_2 VOC – 4 ppm @ 15%O_2 PM_{10} – 0.011 lb/MMBtu	SCR, Oxidation Catalyst, GCPs	BACT-PSD

The RBLC database survey results indicate that available BACT options for the pollutants emitted from NGCC combustion turbines include:

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

A-1.3.3 OXIDES OF NITROGEN BACT

NO_x is primarily formed in combustion processes in two ways: 1) the reaction of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x), and 2) the oxidation of nitrogen contained in the fuel (fuel NO_x). Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is expected that essentially all NO_x emissions from the NGCC combustion turbines will originate as thermal NO_x.

The combustion turbines proposed for the project can achieve a nominal NO_x emission rate of 0.06 lb/MMBtu without post-combustion controls (i.e., without SCR). The remainder of this analysis considers the use of this lower-emitting process in conjunction with add-on controls that eliminate emissions after they are produced by fuel combustion in the turbines.

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

A-1.3.3.1 Identify Control Technologies

Possible control technologies for the proposed turbines were identified by examination of previously issued permits and through RBLC queries for facilities that include NGCC combustion turbines. Table A-1-2 summarizes the NO_X control technologies and permit limits for NGCC combustion turbines similar to those proposed for this project. For this top-down analysis, all of the following technologies were considered to be potentially available for the Units 3 and 4 combustion turbines:

Combustion Process Controls

- LNBs
- XONON

Post-Combustion Controls

- SCR
- EMx (formerly SCONOx)
- SNCR

A-1.3.3.2 Evaluate Technical Feasibility

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

Dry Low NO_x Burners

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

XONON

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

SCR

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

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

$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$
$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$

A fixed-bed catalytic reactor is typically used for SCR systems. The function of the catalyst is to lower the activation energy required for NO_x decomposition to occur. In a natural gas-fired turbine, NO_x removal of 90 percent or higher is theoretically achievable at optimum conditions. Key SCR performance issues focus on flue gas characteristics (temperature and composition), catalyst design, and ammonia distribution. Compounds such as sulfur and certain metals, if present in the exhaust gas stream, can “poison” the catalyst, impacting catalyst activity, inhibiting conversion efficiency, and reducing the useful life of the catalyst.

EMx

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

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

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

- EMx uses a series of dampers to re-route air streams to regenerate the catalyst. The proposed NGCC units are significantly larger than the much smaller facilities where EMx has been used. This would require a significant redesign of the damper system, which raises feasibility concerns regarding reliable mechanical operation of the larger and more numerous dampers that would be required for application to the proposed combustion turbines.
- The EMx catalyst is very susceptible to poisoning by sulfur compounds. Because pipeline natural gas contains some sulfur, a separate catalyst system or filter may be required to absorb SO_2 before it could contact the catalyst bed. However, operation of such an SO_2 absorbtion system on a combustion turbine is not proven, and, upon regeneration, the process would create an H_2S stream requiring treatment.
- EMx would not be expected to achieve lower guaranteed NO_x levels than SCR, and, for reasons described above, it has greater feasibility concerns than SCR for application on large NGCC combustion turbines.

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

SNCR

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

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

A-1.3.3.3 Rank Control Technologies

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

A-1.3.3.4 Evaluate Control Options

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

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

A-1.3.3.5 Select Control Technologies

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

A-1.3.4 CARBON MONOXIDE BACT

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

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

A-1.3.4.1 Identify Control Technologies

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

<u>Combustion Process Controls</u>

- Good Combustion Practices (GCPs)

<u>Post-Combustion Controls</u>

- EMx (formerly SCONOx)
- Oxidation Catalyst

A-1.3.4.2 Evaluate Technical Feasibility

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

Good Combustion Practices

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

EMx

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

Oxidation Catalysts

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

Oxidation catalyst systems typically operate at temperatures between 750 to 1,100ºF (400 to 600ºC), and increased operating temperatures within that range generally result in more effective oxidation reactions. Typical CO to CO_2 conversion efficiencies from a CO oxidation catalyst are 80 to 90 percent, and typical VOC conversion efficiencies are 40 to 50 percent.[2] This technology has been required CO control equipment in a significant number of permits for NGCC combustion turbine projects, and is considered technically feasible for application to an NGCC combustion tubine.

A-1.3.4.3 Rank Control Technologies

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

---

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

A-1.3.4.4 Select Control Technologies

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

A-1.3.5 VOLATILE ORGANIC COMPOUND BACT

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

A-1.3.5.1 Identify Control Technologies

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

<u>Combustion Process Controls</u>

- GCPs

<u>Post Combustion Controls</u>

- Oxidation Catalysts

A-1.3.5.2 Evaluate Technical Feasibility

Good Combustion Practices

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

Oxidation Catalyst

As discussed in Section A-1.4.2, catalytic oxidation is a post-combustion technology wherein the products of combustion are introduced to a catalytic bed at the appropriate temperature point in the HRSG. The catalyst promotes the oxidation of VOC as well as CO, reducing emissions of both. Such systems typically achieve a maximum VOC removal efficiency of up to 50 percent, while providing upwards of 90 percent control for CO. It is also worth noting that a typical additional incentive to using an oxidation catalyst, when feasible, is the incidental control of organic hazardous air pollutants (HAPs). Oxidation catalyst systems are considered technically feasible for controlling VOC emissions from an NGCC combustion turbine.

A-1.3.5.3 Select Control Technology

Catalytic oxidation in conjunction with GCPs is proposed as BACT for VOCs emitted by and NGCC combustion turbine. These practices will meet a VOC emission limit of 0.0016 lb/MMBtu (as CH_4) when operated at full load and, 0.005 lb/MMBtu (as CH_4) when operated at partial loads. This equates to approximately 1 ppmvd at 15 percent O_2 in the stack gases at full load (with or without duct firing), and 3 ppmvd at 15 percent O_2 at 60 percent load.

A-1.3.6 PARTICULATE MATTER BACT

Particulate matter (PM, PM_{10}, and $PM_{2.5}$) emissions from natural gas-fired combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur, dust drawn in from the ambient air that passes through the combustion turbine inlet air filters and particles of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low PM emissions. Virtually all emitted PM is PM_{10} and most is believed to be $PM_{2.5}$.

The EPA has indicated that PM control devices are not typically installed on combustion turbines and that the cost of installing such control devices is prohibitive (EPA, September 1977). When the NSPS for Stationary Gas Turbines (40 CFR 60 Subpart GG) was promulgated in 1979, the EPA acknowledged, "Particulate emissions from stationary gas turbines are minimal." Similarly, the revised Subpart GG NSPS (2004) did not impose a particulate emission standard. Therefore, performance standards for PM control of stationary gas turbines have not been proposed or promulgated at a federal level.

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

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

Use of pipeline natural gas and good combustion control is proposed as BACT for PM/PM_{10} emissions from the proposed combustion turbines. These operational controls will limit combined filterable and condensable PM/PM_{10} emissions to 19.0 lb/hr (per unit).

A-1.3.7 SULFUR DIOXIDE AND SULFURIC ACID MIST BACT

A-1.3.7.1 Identify Control Technologies

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

Pre-Combustion Process Controls

- Use of low-sulfur fuel

Post-Combustion Controls

- Flue Gas Desulfurization (FGD)

Use of Low-Sulfur Fuel

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

Flue Gas Desulfurization

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

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

A-1.3.7.2 Evaluate Technical Feasibility

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

A-1.3.7.3 Select Control Technology

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

A-1.3.8 TOXIC AIR POLLUTANT BACT

TAP emissions from natural gas-fired combustion sources consist of unburned hydrocarbons as well as inert and reactive contaminants in the natural gas. As a result, BACT for TAPs from natural gas-fired combustion turbines is generally considered to be the same as BACT for VOCs and PM from the same source (typically good combustion practices). Studies have also shown that emissions of some TAPs (such as formaldehyde) are oxidized by the oxidation catalyst that is proposed as BACT for CO and VOCs.

A-1.4 AUXILIARY BOILER BACT ANALYSIS

A-1.4.1 PROCESS DESCRIPTION

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

Pollutant emissions from natural gas boiler units include NO_x, PM_{10}, $PM_{2.5}$, CO, SO_2, and VOCs. Annual operation of the boiler will be equal to or less than 2,500 hours of the year at maximum capacity.

A-1.4.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

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

- Good Combustion Practices
- Staged Air/Fuel Combustion or Overfire Air Injection (OFA)
- Low-NO_x burners (LNB)
- Ultra-Low-NO_x burners (ULNB)
- Oxidation Catalysts
- Flue Gas Recirculation (FGR)
- Selective Catalytic Reduction (SCR)
- Low sulfur fuels

A-1.4.3 OXIDES OF NITROGEN BACT

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

TABLE A-1-3
RECENT BACT DETERMINATIONS FOR NATURAL GAS-FIRED AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
OH-0310	02-07-08	Meigs County, OH	American Municipal Power	Auxiliary Boiler	150 MMBtu/hr	NO_X – 21 lb/hr (0.014 lb/MMBtu) SO_X – 0.09 lb/hr (0.00060 lb/MMBtu) CO – 12.6 lb/hr (0.084 lb/MMBtu) VOC – 0.83 lb/hr (0.0055 lb/MMBtu) PM_{10} – 1.14 lb/hr (0.0076 lb/MMBtu) 10% Opacity	Not Described	BACT-PSD; RACT (VE)
GA-0127	01-07-08	Cobb County, GA	Southern Company/Georgia Power	Auxiliary Boilers	200 MMBtu/hr (each of three units)	CO – 0.037 lb/MMBtu VOC – 0.0051 lb/MMBtu	Not Described	LAER (VOC); BACT-PSD (CO)
TX-0499	07-24-06	McClennan County, TX	Sandy Creek Energy Assoc.	Auxiliary Boiler	175 MMBtu/hr	NO_X – 1.8 lb/hr (0.010 lb/MMBtu) SO_X – 0.11 lb/hr (0.00063 lb/MMBtu) CO – 6.1 lb/hr (0.035 lb/MMBtu) VOC – 0.7 lb/hr (0.0040 lb/MMBtu) PM_{10} – 0.88 lb/hr (0.0050 lb/MMBtu)	Not Described	BACT-PSD

TABLE A-1-3 (Continued)
RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
MN-0066	05-16-06	Ramsey County, MN	XCEL Energy	Auxiliary Boiler	160 MMBtu/hr	CO – 0.08 lb/MMBtu VOC – 0.005 lb/MMBtu	Good Combustion	BACT-PSD; MACT (CO)
MN-0062	12-22-05	Sibley County, MN	Heartland Corn Products	Boiler	198 MMBtu/hr	NO_X – 0.04 lb/MMBtu CO – 0.04 lb/MMBtu	Not Described	BACT-PSD
NC-0101	09-25-05	Forsyth County, NC	Forsyth Energy Projects, LLC	Auxiliary Boiler	110.2 MMBtu/hr	NO_X – 15.13 lb/hr (0.14 lb/MMBtu) SO_X – 0.61 lb/hr (0.0055 lb/MMBtu) CO – 9.08 lb/hr (0.082 lb/MMBtu) VOC – 0.59 lb/hr (0.0054 lb/MMBtu) PM_{10} – 0.82 lb/hr (0.007 lb/MMBtu)	Low NO_X burners, Good Combustion Control, and Clean Burning, Low-Sulfur Fuel	BACT-PSD
WI-0228	10-19-04	Marathon County, WI	Wisconsin Public Service	Auxiliary Boiler	229.8 MMBtu/hr	PM_{10} – 0.0075 lb/MMBtu SO_2 – 0.0006 lb/MMBtu NO_X – 0.10 lb/MMBtu CO – 0.08 lb/MMBtu VOC – 0.0054 lb/MMBtu Hg - 0.0001 lb/hr	Low NOx burners, Good Combustion Practices, and Natural Gas Fuel.	BACT-PSD
NE-0024	06-22-04	Washington County, NE	Cargill, Inc.	Boiler	198 MMBtu/hr	NO_X – 0.07 lb/MMBtu 20% Opacity	Low NO_X burners and Induced Draft Flue Gas Recirculation	Other Case-by-Case
MS-0069	06-08-04	Harrison County, MS	E.I. Dupont De Nemours	Boiler	231 MMBtu/hr	PM_{10} – 1.76 lb/hr (0.0076 lb/MMBtu) NO_X – 0.09 lb/MMBtu	Low NO_X burners with FGR and Natural Gas Fuel	BACT-PSD

TABLE A-1-3 (Continued)
RECENT BACT DETERMINATIONS FOR AUXILIARY BOILERS

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
ID-0015	04-05-04	Power County, ID	JR Simplot Company	Boiler	175 MMBtu/hr	NO_X – 7 lb/hr (0.040 lb/MMBtu)	Low NO_X Burners	RACT
WV-0023	03-02-04	Monongahela County, WV	Longview Power, LLC	Auxiliary Boiler	225 MMBtu/hr	CO – 0.04 lb/MMBtu NO_X – 0.0980 lb/MMBtu PM_{10} – 0.0022 lb/MMBtu SO_2 – 0.0040 lb/hr VOC – 0.0054 lb/MMBtu 10% opacity	Low NO_X Burners, Good Combustion Practices, Use of Clean, Low-Sulfur Natural Gas	BACT-PSD

A-1.4.3.1 Ranking of Available Control Technologies

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

- Low-NO_x Burners with SCR 0.011 lb/MMBtu
- Ultra-Low-NO_x Burners 0.011 lb/MMBtu
- Low-NO_x Burners with FGR 0.020 lb/MMBtu
- Low-NO_x Burners with GCP 0.036 lb/MMBtu
- FGR Alone 0.20 lb/MMBtu
- Staged air/fuel or OFA 0.25 lb/MMBtu
- GCP, Conventional Burners 0.40 lb/MMBtu

A-1.4.3.2 Proposed BACT Limits and Control Option

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

A-1.4.4 CARBON MONOXIDE BACT

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

A-1.4.4.1 Ranking of Available Control Technologies

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

- Oxidation Catalyst and GCP 90% control
- GCP 0.037 lb/MMBtu (BACT baseline)

A-1.4.4.2 Consideration of Energy, Environmental and Cost Factors

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

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

Prohibitively high annualized cost is the primary factor that argues against costly add-on control technologies for auxiliary boilers. Since the boiler is not continuously operated, but rather used during relatively infrequent start-up cycles, the emissions abated can be shown to not warrant the investment in capital and operating costs. An annualized cost analysis for the proposed auxiliary boiler is provided to demonstrate this cost barrier. The findings of these cost analyses are summarized in Table A-1-4 and detailed in Table A-1-9.

TABLE A-1-4
ECONOMIC ANALYSIS OF POST-COMBUSTION CO CONTROLS FOR AUXILIARY BOILER

Additional Control Option	Controlled Emissions Basis	Estimated Total Capital Investment	Estimated Annualized Costs ($/yr)	Baseline Emissions or Reduction (tons/yr)	Cost Effectiveness ($ / ton)
Catalytic Oxidizer	90% reduction (0.0037 lb/MMBtu)	$273,400	$76,419	1.22 (reduction)	$62,600
Baseline Option (GCP)	0.037 lb/MMBtu	---	---	1.36 (baseline)	---

The add-on CO control technology for the auxiliary boiler would be cost prohibitive in terms of cost per ton abated. The implementation of a catalytic oxidizer module has an estimated annualized cost of over $76,000, and provides a reduction of 1.22 tons per year, compared with the baseline option of GCP. From these results, the cost effectiveness of the catalytic oxidizer option is conservatively estimated to be not less than $62,000 per ton CO removed.

A-1.4.4.3 Proposed BACT Limits and Control Option

As illustrated in Table A-1-4, the limited operating period for the auxiliary boiler results in prohibitively high annualized cost per ton abated for feasible post-combustion controls. This cost factor, in combination with the environmental and energy related drawbacks, leads to the proposed BACT option of GCP for CO emissions. Grays Harbor Energy proposes that BACT for CO from the auxiliary boiler is 0.037 lb/MMBtu (approximately 50 ppmvd), 3-hour average.

A-1.4.5 SULFUR DIOXIDE, VOLATILE ORGANIC COMPOUND, AND PARTICULATE MATTER BACT

A-1.4.5.1 Ranking of Available Control Technologies

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

- SO_x = 0.0006 lb/MMBtu to 0.082 lb/MMBtu
- VOC = 0.0044 lb/MMBtu to 0.0054 lb/MMBtu
- PM_{10} = 0.0044 lb/MMBtu to 0.0075 lb/MMBtu

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

A-1.4.5.2 Proposed BACT Limits and Control Option

The limited operating period for the auxiliary boiler results in relatively low annual emissions of SO_2, VOC, PM_{10}, and $PM_{2.5}$ meaning that investment in add-on controls would not be cost effective even if they were feasible. Therefore, the use of pipeline natural gas and GCP are proposed as BACT for the auxiliary boiler, and no emission rates are proposed as BACT limits for SO_2, VOCs, PM_{10}, and $PM_{2.5}$. Mass balance calculations based on the sulfur content of the expected source of natural gas indicates SO_2 emissions will be approximately 0.0058 lb/MMBtu (hourly average), 0.0054 lb/MMBtu (24-hour average), and 0.0029 lb/MMBtu (annual average). Boiler vendor information indicates that hourly VOC and PM_{10} emissions are 0.004 lb and 0.005 lb/MMBtu, respectively. $PM_{2.5}$ emissions were based on the filterable portion of the calculated PM_{10} emission rate using fraction provided in AP-42 Section 1.4.

A-1.4.6 TOXIC AIR POLLUTANT BACT

TAP emissions from natural gas-fired combustion sources consist of unburned hydrocarbons as well as inert and reactive contaminants in the natural gas. As a result, BACT for TAPs from natural gas-fired boilers is generally considered to be the same as BACT for VOCs and PM from the same source.

A-1.5 COOLING TOWER BACT ANALYSIS

A-1.5.1 PROCESS DESCRIPTION

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

A-1.5.2 COMMERCIALLY AVAILABLE CONTROL TECHNOLOGIES

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

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

Table A-1-5 summarizes recent BACT determinations for utility-scale mechanical draft cooling towers. The commercially available techniques listed to limit drift PM_{10} releases from utility-scale cooling towers include:

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

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

In addition to the use of high efficiency drift eliminators, management of the tower water balance to control the concentration of dissolved solids in the cooling water can also reduce particulate emissions. Dissolved solids accumulate in the cooling water due to increasing concentration of dissolved solids in the make-up water as the circulating water evaporates, and, secondarily, the addition of anti-corrosion, anti-biocide additives. However, to maintain reliable operation of the tower without the environmental impact of frequent acid wash cleanings, the water balance must be considered. The proposed cooling tower design will be based on 12 cooling water cycles (i.e., the concentration of dissolved solids in the circulating water will be, on average, 12 times that of the introduced make-up water), and a total dissolved solids (TDS) concentration of 200 ppmw in the make up water, which translates to a cooling water TDS concentration of 2,400 ppmw.

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

A-1.5.3 INFEASIBLE CONTROL MEASURES

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

TABLE A-1-5
RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
LA-0148	05-28-08	Red River Parish, LA	Red River Environmental Products, LLC	Cooling Towers	10,750 gal/min	PM – 0.41 lb/hr	Drift Elimination System	BACT-PSD
LA-0224	03-20-08	Caddo Parish, LA	Southwest Electric Power Company	Cooling Tower	140,000 gal/min	PM – 1.4 lb/hr	Mist Eliminators	BACT-PSD
LA-0221	11-30-07	St. Charles Parish, LA	Entergy Louisiana, LLC	Cooling Tower	5,000 gal/min	PM – 0.5 lb/hr	Drift Eliminator with 99.999% Control Eff.	BACT-PSD
ND-0024	09-14-07	Stutsman County, ND	Great River Energy	Cooling Tower	80,000 gal/min	PM – 0.0005% of cooling water	Drift Eliminator	BACT-PSD
MN-0070	09-07-07	Itasca County, MN	Minnesota Steel Industries, LLC	Cooling Tower	Not Provided	PM, PM_{10} – 0.005% drift rate	Design to minimize drift	BACT-PSD
IA-0089	08-08-07	Chickasaw County, IA	Homeland Energy Solutions, LLC	Cooling Tower	5,000 gal/min	PM, PM_{10} – 0.0005% drift	Drift Eliminator/ Demister	BACT-PSD
IA-0088	06-29-07	Linn County, IA	Archer Daniels Midland	Cooling Tower	150,000 gal/min	PM, PM_{10} – 0.0005% drift	Drift Eliminator	BACT-PSD
LA-0211	12-27-06	St. John the Baptist Parish, LA	Marathon Petroleum Co., LLC	Cooling Towers	30,000 & 96,250 gal/min	PM_{10} – 0.005% drift	High Efficiency Drift Eliminators	BACT-PSD
FL-0294	12-22-06	Pasco County, FL	Progress Energy Florida	Cooling Towers	660,000 gal/min	PM – 108 tons/year	Drift Eliminators	BACT-PSD

TABLE A-1-5 (Continued)
RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
WV-0024	04-26-06	Greenbrier County, WV	Western Greenbrier Co-Generation, LLC	Cooling Tower	55,000 gal/min	PM – 0.79 lb/hr	Drift Eliminators with 0.0005% drift	BACT-PSD
IA-0082	04-19-06	Cerro Gordo County, IA	Golden Grain Energy	Cooling Tower	NA	PM_{10} – 1.33 lb/hr	Mist Eliminators	BACT-PSD
LA-0202	02-23-06	Rapides Parish, LA	Cleco Power, LLC	Cooling Tower	301,874 gal/min	PM_{10} – 1.13 lb/hr 3.31 tons/year	Drift Eliminators	BACT-PSD
OR-0041	08-08-05	Umatilla County, OR	Diamond Wanapa I LP	Cooling Tower	6.2 ft^3/sec	PM – 3532 ppmw	High Efficiency 0.0005% Drift Eliminators; Limit TDS to < 3,532 PPMW.	BACT-PSD
CO-0057	07-05-05	Pueblo County, CO	Public Service Company of Colorado	Cooling tower	140,650 gal/min	PM – NA PM_{10} - NA	RACT is drift eliminators to achieve 0.0005 % drift or less.	BACT-PSD
LA-0192	06-06-05	Orleans Parish, LA	Cresent City Power LLC	Cooling Tower	290,200 gal.min	PM_{10} – 2.61 lb/hr	TDS = 30,000 PPM 0.0001% drift annual average (Marley Excel Drift Eliminators)	BACT-PSD
IN-0119	05-31-05	Dekalb County, IA	Auburn Nugget	Cooling Tower	23,450 gal/min	PM – 0.0050% of Throughput 20% opacity	NA	BACT-PSD
NV-0036	05-05-05	Eureka County, NV	Newmont Nevada Energy Investment LLC	Cooling Tower	NA	PM_{10} – 0.0005% drift	Drift Eliminators	BACT-PSD

TABLE A-1-5 (Continued)
RECENT BACT DETERMINATIONS FOR COOLING TOWERS

Permit or RBLC ID	Permit Issuance Date	Location/ Facility	Company	System Description	Maximum Throughput	Limit(s)	Control Option	Basis
AZ-0046	04-14-05	Yuma, AZ	Arizona Clean Fuels LLC	Cooling Tower	NA	PM – 1.6 lb/hr	High Efficiency Drift Eliminators	BACT-PSD
NY-0093	03-31-05	Nassau County, NY	Igen-Nassau Energy Corporation	Cooling Tower	NA	PM_{10} – 0.0005% drift	NA	BACT-PSD
NE-0031	03-09-05	Otoe County, NE	Omaha Public Power District OPPD	Cooling Tower	NA	PM_{10} – 0.0010 lb/hr	High Efficiency Mist Eliminators - 0.0005% drift	BACT-PSD
WA		Cherry Point	BP Refinery	Cogeneration Cooling Tower	NA	7.2 tpy	0.001% drift	BACT-PSD
WA		Hanging Rock Energy Facility	Duke Energy	Combined Cycle Unit Cooling Tower	NA	3.6 lb/hr	Drift Eliminators	BACT-PSD
WA		Mint Farm Generation		Combined Cycle Unit Cooling Tower	NA	1.08 tpy	Drift Eliminators	BACT-PSD
WA		Wallula Power Project		Combined Cycle Unit Cooling Tower	NA	3.7 lb/hr	Water pre-treatment and 0.0005% drift rate	LAER

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

A-1.5.4 RANKING OF AVAILABLE CONTROL MEASURES

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

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

- Combinations of high-efficiency drift eliminators and TDS limit
- High-Efficiency drift eliminators to control drift to as low as 0.0005% of circulating flow
- High-efficiency drift eliminators, as low as 0.001% of circulating flow
- Limitations on TDS concentrations in the circulating water
- Installation of Drift Eliminators (no efficiency specified)

A-1.5.5 CONSIDERATION OF ENERGY, ENVIRONMENTAL AND COST FACTORS

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

Even incremental improvement in drift control involves substantial changes in the tower design. First, the velocity of the draft air that is drawn through the tower media must be reduced compared to “conventional” specifications. This is necessary to use drift eliminator media with smaller passages (to improve droplet capture) without encountering unacceptably high pressure drop. Since reducing the air velocity also reduces the heat transfer coefficient of the tower, it is likely that a proportional increase in the overall size of the media will be needed. For example, a 12-cell tower may need to be expanded to 14 cells in order to accommodate higher drift eliminator efficiency for the same heat rejection duty. These changes will also result in an energy penalty in the form of larger and higher powered fans to accommodate the improved droplet capture. More importantly, there is a substantial increase in both tower operating costs and capital costs that deliver relatively few tons of PM_{10} abatement.

Adopting a TDS limit for the circulating water is usually viewed as a measure that benefits air quality by reducing the dissolved salts that can be precipitated from drift aerosols. To reduce

TDS the facility must introduce a higher volume flow of make-up water to the tower. This has the potential environmental disadvantage of increasing the overall plant water requirements.

A-1.5.6 PROPOSED BACT LIMITS AND CONTROL OPTION

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

A-1.6 INTERNAL COMBUSTION ENGINE BACT ANALYSIS

A-1.6.1 PROCESS DESCRIPTION

A pump powered by a nominal 275 hp diesel engine will be installed to provide water for fire suppression when power is from the grid is not available to run the electric firewater system. In addition, a 600 hp diesel-fueled engine will drive a 400 kw generator to provide emergency power when power from the grid is not available. Both engines will burn ultra-low sulfur distillate oil. Other than plant emergency situations, each engine will be operated no more than 26 hours per year for routine testing, maintenance, and inspection purposes.

Although the engine makes and models have not yet been specified, the emission standards for stationary engines in 40 CFR Part 60 Subpart IIII (Stationary Compression Ignition Reciprocating Engine NSPS) were used to calculate criteria pollutant emissions.[3]

A-1.6.2 OXIDES OF NITROGEN BACT

A-1.6.2.1 Available Control Technologies and Technical Feasibility

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

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

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

---

[3] Subpart IIII limits the sum of NO_x and VOC emissions, we have conservatively assumed the engine would emit both NO_X and VOC and the standard for the sum of the two pollutants.

into the exhaust stream. Another potentially available technology that has been eliminated from consideration on the grounds that it is technically infeasible is:

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

A-1.6.2.2 Energy and Environmental Considerations

There are several distinguishing factors between the two technically-feasible options with regard to energy and environmental impacts. One drawback associated with SCR systems is the environmental risk of handling and using ammonia reagent solutions. Most SCR catalyst modules can operate well without excess reagent. However, this requires particular attention to the controlled injection of the reagent in response to changes in load, temperature, and other parameters. Absent an emergency situation, the engines proposed for the project will operate only for brief testing and maintenance checks; Subpart IIII limits these checks to 100 hours per year but this application proposes no more than 26 hours of operation (per engine) per year. The minimal operation significantly reduces the effectiveness of the post-combustion controls.

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

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

TABLE A-1-6
RECENT BACT DETERMINATIONS FOR EMERGENCY INTERNAL COMBUSTION ENGINES ≤ 500 HP

Permit or RBLC ID	Permit Issuance Date	Location	Company	System Description	Maximum Production Rate	Limit(s)	Control Option	Basis
LA-0224	03-20-08	Caddo Parish, LA	Southwest Electric Power Co.	Diesel Fire Pump	310 HP	NO_x – 9.61 lb/hr CO – 2.07 lb/hr PM_{10} – 0.68 lb/hr SO_2 – 0.64 lb/hr VOC – 0.77 lb/hr	Low-Sulfur fuel, limited operation hours, and proper engine maintenance	BACT-PSD
MN-0070	09-07-07	Itasca County, MN	Minnesota Steel Industries, LLC	Diesel Fire Water Pumps	Not Provided	SO_2 – 0.05% in fuel VE – 5%	Limited Sulfur in fuel, limited hours	BACT-PSD
CA-1144	04-25-07	Riverside County, CA	Caithness Blythe II, LLC	Fire Pump	303 HP	NO_x – 7.5 lb/hr CO – 0.7 lb/hr PM_{10} – 0.1 lb/hr	Fuel with less than 0.05% sulfur by weight	BACT-PSD
IA-0084	11-30-06	Clinton County, IA	ADM Corn Processing	Fire Pump Engine	500 HP	VOC – 3 g/HP-hr	GCP	BACT-PSD
OK-0110	10-21-05	Muskogee County, OK	Dalitalia, LLC	Emergency Generator	Not Provided	CO – 0.0067 lb/HP-hr PM_{10} – 0.0022 lb/HP-hr VOC – 0.0025 lb/HP-hr	GCP	Not Prov.
NC-0101	09-29-05	Forsyth County, NC	Forsyth Energy Projects, LLC	Emergency Generator and Firewater Pump	11.40 MMBtu/hr	NO_x – 36.48 lb/hr CO – 9.69 lb/hr PM_{10} – 1.14 lb/hr SO_2 – 0.58 lb/hr VOC – 1.04 lb/hr	Emergency use only	BACT-PSD
LA-0192	06-06-05	Orleans County, LA	Cresent City Power, LLC	Firewater Pump	425 HP	NO_x – 8.9 lb/hr CO – 1.88 lb/hr PM_{10} – 0.14 lb/hr SO_2 – 0.61 lb/hr VOC – 0.05 lb/hr	Good engine design and proper operating practices	BACT-PSD
OH-0252	12-28-04	Lawrence County, OH	Duke Energy Hanging Rock ,LLC	Firewater Pump	265 HP	NO_x – 8.2 lb/hr CO – 1.8 lb/hr PM – 0.66 lb/hr SO_2 – 0.10 lb/hr VOC – 0.66 lb/hr	500 hr/yr	BACT-PSD

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

A-1.6.2.3 Ranking of Control Options

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

The option offering the next highest control level is combustion process modifications, as would be implemented as standard equipment (i.e. no additional cost) in the selected engines. Advanced combustion design allows the engines to operate at rated horsepower, while burning an optimized fuel mix. This feature includes ignition timing retard to reduce cylinder temperatures for lean mixtures. The controls are also designed to optimize the air/fuel ratio and ignition timing in response to actual operating conditions.

A-1.6.2.4 Economic Analysis for Controls

Since advanced NO_x controls is a standard feature of the currently available new engines, the emissions reported by vendors for this package are taken as the base case in this BACT analysis. Addition of SCR is then analyzed as the next incremental control technology, in terms of both control level and cost. Table A-1-7 provides the results of the cost effectiveness analysis for the emergency generator and firewater pump engines.

TABLE A-1-7
ECONOMIC ANALYSIS OF POST-COMBUSTION SCR CONTROLS FOR IC ENGINES

Emergency Engine	Controlled Emissions Basis (90% reduction)	Estimated Total Capital Investment [1]	Estimated Annualized Costs [2] ($/yr)	Emissions Reduction (tons/yr)	Cost Effectiveness ($ / ton)
275 hp Fire Water Pump	0.0018 tons/yr	$243,844	$78,900	0.016	$4,970,000
600 hp Emer. Gen.	0.0051 tons/yr	$243,844	$78,900	0.046	$1,709,000

[1] Estimated capital cost for SCR control based on 300 hp diesel engine. Cost estimate should be conservative for larger emergency generator engine.

[2] Annualized costs include capital recovery (10 year equipment life and 7 percent interest), maintenance, and operation costs.

As shown in Table A-1-7, the annualized operating costs for addition of SCR to an IC engine would be about $79,000 per year. Assuming a 90 percent control efficiency, the SCR controls would reduce up to 0.05 tons of NO_X per year for the emergency generator. The cost effectiveness results in more than $1,700,000 per ton removed, which represents a prohibitively high cost for this BACT option.

A-1.6.2.5 Proposed BACT

SCR has been shown to be cost prohibitive as BACT for the project engines. The proposed BACT for the proposed engines is the combustion modifications supplied as standard equipment with the candidate types of engines which enable the manufacturer to certify the engine under Subpart IIII.

A-1.6.3 CARBON MONOXIDE AND VOLATILE ORGANIC COMPOUND BACT

NO_x, CO and VOC emissions for the engines were calculated using the stationary fire pump engine standards in Subpart IIII.[4] The engines selected for this project would be certified by the manufacturer to achieve the applicable standards in Subpart IIII, and would be operated less than 26 hours per year in a non-emergency mode, as required by Subpart IIII.

A-1.6.3.1 Technically-Feasible Controls

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

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

Catalytic Oxidation – This control technology employs a module containing an oxidation catalyst that is located in the exhaust path of the engine. In the catalyst module, CO and VOCs diffuse through the surfaces of a ceramic honeycomb structure coated with noble metal catalyst particles. Oxidation reactions on the catalyst surface forms carbon dioxide and water. Typical vendor indications are that 95 percent reduction in CO and 50 percent reduction in VOC emissions should be achieved.

A-1.6.3.2 Cost Effectiveness Analysis

Table A-1-7 provides the results of the cost effectiveness analysis for the emergency generator and firewater pump engines.

---

[4] Subpart IIII limits the sum of NO_x and VOC emissions, we have conservatively assumed the engine would emit both NO_X and VOC and the standard for the sum of the two pollutants.

TABLE A-1-8
ECONOMIC ANALYSIS OF POST-COMBUSTION CATALYTIC OXIDATION CONTROLS FOR IC ENGINES

Emergency Engine	Controlled Emissions Basis (90% CO and 50% VOC reductions)	Estimated Annualized Costs [1] ($/yr)	Total Emissions Reduction (tons/yr)	Cost Effectiveness ($ / ton)
275 hp Fire Water Pump	0.00076 tons CO/yr 0.0088 tons VOC/yr	$15,616	0.023	$669,000
600 hp Emer. Gen.	0.0022 tons CO/yr 0.026 tons VOC/yr	$29,241	0.068	$428,000

[1] Annualized costs estimated by IC engine exhaust flow rates (1,952 cfm – fire water pump and 3,655 cfm – emergency generator) and a conservative annualized cost for the catalytic oxidation controls of $8/scfm (EPA-452/F-03-018).

As shown in Table A-1-8, the low end of estimated annualized operating costs for addition of catalytic oxidation to would be approximately $16,000 – 29,000 for the IC engines. Assuming 95 percent CO and 50 percent VOC control efficiencies, the catalytic oxidation controls would reduce up to 0.068 tons of total CO and VOC emissions per year for the emergency generator. The cost effectiveness results in more than $428,000 per ton removed, which represents a prohibitively high cost for this BACT option.

A-1.6.3.3 Proposed BACT

Catalytic oxidation has been shown to be cost prohibitive as BACT for the engines proposed for this project. Grays Harbor Energy asserts that BACT is the combustion modifications supplied by the manufacturer as standard equipment that enable the engines to meet the emission standards in Subpart IIII. Annual emissions would be limited by restricting non-emergency hours of operation to less than 26 hours per year.

A-1.6.4 SULFUR DIOXIDE AND PARTICLUATE MATTER BACT

The fire pump engine proposed for the project will have annual emissions of 0.000043 tons of SO_2, 0.0024 tons of PM_{10}, and 0.0020 tons of $PM_{2.5}$. The emergency generator engine proposed for the project will have annual emissions of 0.000095 tons of SO_2, 0.0026 tons of PM_{10}, and 0.0021 tons of $PM_{2.5}$.The SO_2 emission rate was calculated using the equation provided in Table 3.4-1 of AP-42 Section 3.4 (Large Stationary Diesel and All Stationary Dual-Fuel Engines) and ultra low sulfur diesel fuel content of 15 ppm by weight. PM_{10} emissions were based on Subpart IIII standards, and $PM_{2.5}$ emissions were based on the calculated PM_{10} emission rate and the ratio of the $PM_{2.5}$ and PM_{10} emission factors provided in AP-42 Section 3.4. Given these low emissions, there are no available technologies beyond good combustion controls that are considered to provide feasible or cost effective emission control. Use of engines certified by manufacturers to meet Subpart IIII emission standards, use of ULSD fuel, and limitation of non-emergency operation to no more than 26 hours per year will provide relatively low emissions of SO_2, PM_{10}, and $PM_{2.5}$ and are proposed as BACT measures for these pollutants.

TABLE A-1-9
CATALYTIC OXIDIZER COST EFFECTIVENESS CALCULATIONS
Natural Gas-Fired Auxiliary Boiler - 30 MMBtu/hr

CAPITAL COSTS		
DIRECT COSTS	**COST**	**Source**
I. Purchased Equipment		
a. Primary Equipment (Fixed Bed Catalytic, 50% Heat Recovery)	$139,673	OAQPS
b. Catalyst Replacement Allowance	$5,000	Engineering Estimate
b. Instrumentation (0.1*a)	$13,967	OAQPS
c. Sales tax (0.03*a)	$4,190	OAQPS
d. Freight (0.05*a)	$6,984	OAQPS
Total Purchases Equipment Cost [TEC]	$169,814	*Calculation*
II. Direct Installation Costs		
a. Foundations and Supports (0.08*TEC)	$13,585	OAQPS
b. Handling and Erection (0.14*TEC)	$23,774	OAQPS
c. Electrical (0.04*TEC)	$6,793	OAQPS
d. Piping (0.02*TEC)	$3,396	OAQPS
e. Insulation for Ductwork (0.01*TEC)	$1,698	OAQPS
f. Painting (0.01*TEC)	$1,698	OAQPS
Total Direct Installation Costs [TDC](I+II)	$50,944	*Calculation*
INDIRECT COSTS		
III. Indirect Installation		
a. Engineering and Supervision (0.10*TEC)	$16,981	OAQPS
b. Construction and Field Expenses (0.05*TEC)	$8,491	OAQPS
c. Contractor Fee (0.10*TEC)	$16,981	OAQPS
d. Contingencies (0.03*TEC)	$5,094	OAQPS
IV. Other Indirect Costs		
a. Startup and Testing (0.03*TEC)	$5,094	OAQPS
Total Indirect Costs [TIC](III+IV)	$52,642	*Calculation*
Total Capital Costs [TCC] (TEC+TDC+TIC)	$273,400	*Calculation*
Total Annualized Capital Costs [TACC] (10 years @ 7% interest)	**$38,926**	*Calculation*
DIRECT AND INDIRECT ANNUALIZED COSTS		
DIRECT OPERATING COSTS (DOC)		
I. Labor for operations ($35.29/person-hour)(0.5 hr/shift)(1 shifts/8 hours)(2,500 hours/yr)	$5,514	Engineering Estimate
II. Supervisory Labor (0.15* operations labor)	$827	OAQPS
III. Maintenance Labor ($35.29/person-hour)(0.5 hr/shift)(1 shifts/8 hours)(2,500 hours/yr)	$5,514	Engineering Estimate
IV. Maintenance Materials (100% of maintenance labor)	$5,514	OAQPS
V. Utility costs		
a. Electricity - Fan (12 kWh)($0.08/kW-hr)(2,500 hr/yr)	$1,500	Engineering Estimate
VI. Fuel Penalty (none)	$0	
VII. Waste Disposal	$0	
INDIRECT OPERATING COSTS (IOC)		
VII. Overhead (0.6*O&M costs(I-IV of DOC)	$10,422	OAQPS
VIII. Administration (0.02*TCC)	$5,468	OAQPS
IX. Insurance (0.01*TCC)	$2,734	OAQPS
Total Direct and Indirect Annualized Costs [TDIAC] (DOC+IOC)	**$37,493**	*Calculation*
TOTAL ANNUALIZED COSTS [TAC $_{OC}$] (TACC+TDIAC)	**$76,419**	*Calculation*

OAQPS "EPA Air Pollution Cost Manual" Sixth Edition, January 2002, EPA/452/B-02-001
Office of Air Quaility Planning and Standards (OAQPS).

Calculation The calculated exhaust from the boiler is 4,966 dscfm. Operating approximately 2,500 hours/year

Appendix A-2

Combustion Turbine Emission Rate Calculations

Combustion Turbine Criteria Pollutant Emission Rates (Single "Stored" Unit)

Parameter	Units	Rated Temperature			Low Temperature			High Temperature		
		100%+DB	100% load	60% load	100%+DB	100% load	60% load	100%+DB	100% load	60% load
Performance Data										
GT gross load	%	100	100	60	100	100	60	100	100	60
Net power	MW	631	509	339	658	536	356	586	465	309
Net heat rate	Btu/kWh	7260	6821	7382	7325	6911	7420	7337	6859	7503
Emission rates										
NO_X emissions	ppmvd @ 15% O_2	2	2	2	2	2	2	2	2	2
	lb/hr	18.890011	14.838794	10.681806	19.746899	15.579427	11.08562	17.938277	14.152381	10.340212
CO emissions	ppmvd @ 15% O_2	2	2	2	2	2	2	2	2	2
	lb/hr	11.498268	9.0323095	6.501969	12.019851	9.4831294	6.7477685	10.918951	8.614493	6.2940423
VOC emissions (as CH_4)	ppmvd @ 15% O_2	1	1	3	1	1	3	1	1	3
	lb/hr	3.2852194	2.5806599	5.5731163	3.4342432	2.7094656	5.7838016	3.1197004	2.4612837	5.3948934
	lb/MMbtu	0.0014343	0.0014866	0.004454	0.001425	0.0014629	0.0043791	0.0014512	0.0015434	0.0046539
PM_{10} emissions[2]	lb/hr (from GE, w/sulf.)	19	19	19	19	19	19	19	19	19
	lb/MMBtu (GE)	0.008295	0.0109451	0.0151848	0.0078841	0.0102584	0.0143857	0.0088383	0.0119143	0.0163904
	gr/dscf (GE)	0.0016815	0.0021406	0.0029737	0.0016086	0.0020389	0.0028654	0.0017708	0.0022444	0.0030719
$PM_{2.5}$ emissions (filterable only)	fraction of PM10	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	lb/hr (filterable PM_{10})	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
SO_2 emissions	lb/hr (1-hr average)	13.228621	10.025694	7.2264057	13.91817	10.69681	7.6278563	12.415515	9.2100578	6.6948681
	lb/hr (3-hr average)	13.228621	10.025694	7.2264057	13.91817	10.69681	7.6278563	12.415515	9.2100578	6.6948681
	lb/hr (24-hr average)	12.199728	9.2459175	6.6643519	12.835645	9.8648359	7.0345786	11.449864	8.49372	6.1741561
	lb/hr (annual average)	6.7037795	5.0806535	3.6620771	7.0532173	5.4207506	3.8655175	6.2917271	4.6673191	3.3927133
H_2SO_4 emissions (1/3 conv. of SO_2)	lb/hr	6.7521087	5.1172811	3.6884779	7.1040657	5.4598301	3.893385	6.3370857	4.700967	3.4171723
NH_3 emissions	ppmvd @ 15% O_2	5	5	5	5	5	5	5	5	5
	lb/hr	17.452728	13.709755	9.8690601	18.244417	14.394036	10.242149	16.573408	13.07557	9.553457
Exhuast Gas										
Stack exhaust gas mass flow[4]	lb/hr	3591893.3	3568000.3	2568000	3859893	3836000	2674000	3299893	3276000	2449000
	kg/hr	1629272.1	1618434.3	1164837.2	1750836	1739998.2	1212918.4	1496821.6	1485983.9	1110859.1
Stack exhaust gas temperature	°F	162.50938	178.33046	163.44009	161.59048	176.99139	159.32253	166.57114	180.25708	168.33224
	K	345.65521	354.4447	346.17227	345.14471	353.70077	343.88474	347.91174	355.51504	348.89014
Stack exhaust gas volume flow - actual	m^3/hr	1635528.4	1660957.3	1167545.3	1748440.3	1773984.7	1202721.2	1523288	1545569	1133394.1
	acfm	962635.7	977602.54	687191.22	1029093.1	1044128	707894.95	896573.5	909687.55	667090.59
Stack exhaust gas volume flow - Normal	Nm^3/hr	1292457.3	1280003.6	921260.95	1383728.2	1369982.6	955329.65	1195953.1	1187494.5	887346.96
Stack exhaust gas volume flow - dry, std.	dscfm	731574.96	738271.99	531350.76	792261.97	800300.76	557110.92	662590.96	665144.48	498078.15
Stack exhaust gas volume flow - corrected	dscfm @ 15% O_2	1318240.4	1035526	745430.38	1378038.3	1087211.1	773610.53	1251823.6	987624.64	721592.24
	m^3/hr	2239704.7	1759369.9	1266494.3	2341302	1847183.4	1314372.6	2126861.8	1677984.9	1225993
Stack exhaust gas velocity	ft/s	63.048654	64.02892	45.008181	67.401338	68.38606	46.364189	58.721853	59.580769	43.691673
	m/s	19.21723	19.516015	13.718494	20.543928	20.844071	14.131805	17.898421	18.160219	13.317222
N2	vol−%	73.648382	74.111774	74.11124	74.388499	75.019389	74.957225	72.214932	72.024607	72.096335
O2	vol−%	10.268665	12.624454	12.622908	10.637705	12.884831	12.707193	9.7532146	12.139519	12.352357
CO2	vol−%	4.8086848	3.6873084	3.6880147	4.7231298	3.6791973	3.7602313	4.8740197	3.6486298	3.5511684
H2O	vol−%	10.39132	8.6911954	8.6925767	9.358836	7.5204693	7.6799862	12.292083	11.326913	11.138944
Ar	vol−%	0.8829474	0.8852674	0.8852609	0.8918303	0.8961127	0.8953641	0.8657504	0.8603313	0.8611956
SO2	vol−%	0	0	0	0	0	0	0	0	0
N2	MW - 28 kg/kmol	20.621547	20.751297	20.751147	20.82878	21.005429	20.988023	20.220181	20.16689	20.186974
O2	MW - 32 kg/kmol	3.2859728	4.0398254	4.0393305	3.4040656	4.1231461	4.0663018	3.1210287	3.8846462	3.9527543
CO2	MW - 44 kg/kmol	2.1158213	1.6224157	1.6227265	2.0781771	1.6188468	1.6545018	2.1445687	1.6053971	1.5625141
H2O	MW - 18 kg/kmol	1.8704377	1.5644152	1.5646638	1.6845905	1.3536845	1.3823975	2.212575	2.0388443	2.0050098
Ar	MW - 39.95 kg/kmol	0.3527375	0.3536643	0.3536617	0.3562862	0.357997	0.357698	0.3458673	0.3437024	0.3440476
Exhaust MW	kg/kmol	28.246516	28.331617	28.33153	28.351899	28.459103	28.448922	28.044221	28.03948	28.0513
Ambient Conditions										
Air temperature	°F	59	59	59	20	20	20	90	90	90
Air humidity	%	60	60	60	30	30	30	60	60	60
Air pressure	psia	14.54	14.54	14.54	14.54	14.54	14.54	14.54	14.54	14.54
Air pressure	kPa	101.35	101.35	101.35	101.35	101.35	101.35	101.35	101.35	101.35
Universal Gas Constant	kJ/(kmol*K)	8.314	8.314	8.314	8.314	8.314	8.314	8.314	8.314	8.314
Operating Assumptions										
Duct burner status		on	off	off	on	off	off	on	off	off
Fuel LHV	Btu/lb	21136	21136	21136	21136	21136	21136	21136	21136	21136
Fuel HHV	Btu/lb	23274	23274	23274	23274	23274	23274	23274	23274	23274
Fuel S content (1hr avg)	gr/lb natural gas	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545
Fuel S content (3hr avg)	gr/lb natural gas	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545
Fuel S content (24hr avg)	gr/lb natural gas	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636
Fuel S content (ann avg)	gr/lb natural gas	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091
Fraction of SO2 converted to sulfate in exhaust	%	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333
Fuel mass use rate	lb/hr	98415.829	74587.286	53761.665	103545.8	79580.132	56748.303	92366.632	68519.27	49807.231
CT heat input (HHV)	MMBtu/hr	1734.447	1735.9445	1251.249	1853.842	1852.148	1320.76	1593.658	1594.7175	1159.2135
DB heat input (HHV)	MMBtu/hr	556.08299	0	0	556.08299	0	0	556.08299	0	0
Total heat input (HHV)	MMBtu/hr	2290.53	1735.9445	1251.249	2409.925	1852.148	1320.76	2149.741	1594.7175	1159.2135

Combustion Turbine Criteria Pollutant Emission Rates (Single "Uprate" Unit)

Parameter	Units	Rated Temperature			Low Temperature			High Temperature		
		100%+DB	100% load	60% load	100%+DB	100% load	60% load	100%+DB	100% load	60% load
Performance Data										
GT gross load	%	100	100	60	100	100	60	100	100	60
Net power	MW	656	534	352	683	561	370	609	488	323
Net heat rate	Btu/kWh	7115	6665	7242	7175	6751	7283	7190	6702	7339
Emission rates										
NO_X emissions	ppmvd @ 15% O_2	2	2	2	2	2	2	2	2	2
	lb/hr	19.168762	15.145664	10.880477	20.007981	15.87111	11.274915	18.186515	14.423425	10.507693
CO emissions	ppmvd @ 15% O_2	2	2	2	2	2	2	2	2	2
	lb/hr	11.667942	9.2191001	6.6228988	12.178771	9.6606757	6.8629917	11.070053	8.7794764	6.3959872
VOC emissions (as CH_4)	ppmvd @ 15% O_2	1	1	3	1	1	3	1	1	3
	lb/hr	3.3336978	2.6340286	5.6767704	3.4796488	2.7601931	5.8825643	3.1628722	2.5084218	5.4822747
	lb/MMbtu	0.0014285	0.0014802	0.0044538	0.0014201	0.0014576	0.004366	0.0014447	0.0015339	0.0046254
PM_{10} emissions[2]	lb/hr (from GE, w/sulf.)	19	19	19	19	19	19	19	19	19
	lb/MMBtu (GE)	0.0081415	0.0106768	0.0149067	0.0077543	0.0100335	0.0141017	0.0086784	0.0116187	0.0160304
	gr/dscf (GE)	0.0016571	0.0020972	0.0029194	0.0015876	0.0020014	0.0028172	0.0017466	0.0022023	0.0030229
$PM_{2.5}$ emissions (filterable only)	fraction of PM10	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	lb/hr (filterable PM_{10})	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75	4.75
SO_2 emissions	lb/hr (1-hr average)	13.478059	10.27756	7.3612198	14.151133	10.93653	7.7814518	12.6443	9.4443668	6.8452294
	lb/hr (3-hr average)	13.478059	10.27756	7.3612198	14.151133	10.93653	7.7814518	12.6443	9.4443668	6.8452294
	lb/hr (24-hr average)	12.429765	9.478194	6.7886804	13.050489	10.085911	7.1762278	11.660854	8.7098049	6.3128227
	lb/hr (annual average)	6.8301853	5.2082899	3.7303959	7.1712746	5.5422321	3.9433541	6.4076669	4.7860583	3.468911
H_2SO_4 emissions (1/3 conv. of SO_2)	lb/hr	6.8794258	5.2458378	3.7572892	7.2229741	5.5821874	3.9717827	6.4538613	4.8205622	3.4939192
NH_3 emissions	ppmvd @ 15% O_2	5	5	5	5	5	5	5	5	5
	lb/hr	17.71027	13.993277	10.052614	18.485634	14.663526	10.417041	16.802759	13.325991	9.7081949
Exhuast Gas										
Stack exhaust gas mass flow[4]	lb/hr	3538893.3	3515000	2567000	3789893	3766000	2672000	3267893.3	3244000.3	2430000
	kg/hr	1605231.4	1594393.5	1164383.6	1719084.2	1708246.4	1212011.2	1482306.7	1471468.9	1102240.8
Stack exhaust gas temperature	°F	161.83318	177.03215	163.60005	160.77657	175.39244	159.42381	166.16074	179.707	167.94673
	K	345.27954	353.72342	346.26114	344.69254	352.81247	343.94101	347.68374	355.20944	348.67596
Stack exhaust gas volume flow - actual	m^3/hr	1610779	1634002.8	1167784.1	1715725.8	1738367.9	1202396.6	1508410.6	1529991.9	1124404.4
	acfm	948068.73	961737.73	687331.8	1009838.1	1023164.7	707703.93	887816.95	900519.25	661799.46
Stack exhaust gas volume flow - Normal	Nm^3/hr	1274284.3	1261799	921212.93	1359618.9	1345857.2	954915.6	1185049.2	1176537.7	880849.57
Stack exhaust gas volume flow - dry, std.	dscfm	718772.54	725493.65	530448.01	775696.6	783745.11	556023.44	654606.99	657197.47	493340.91
Stack exhaust gas volume flow - corrected	dscfm @ 15% O_2	1337693	1056941	759294.61	1396257.9	1107566.2	786820.5	1269146.9	1006539.5	733279.9
	m^3/hr	2272754.9	1795754.1	1290049.7	2372257.3	1881767	1336816.5	2156294.2	1710121.4	1245850.5
Stack exhaust gas velocity	ft/s	62.094578	62.989841	45.017388	66.140215	67.013053	46.351678	58.148336	58.980284	43.345126
	m/s	18.926427	19.199303	13.7213	20.159537	20.425579	14.127992	17.723613	17.977191	13.211594
N2	vol−%	73.527004	74.00106	74.053001	74.263057	74.906521	74.902572	72.115108	71.931681	72.021568
O2	vol−%	9.9196292	12.30454	12.454614	10.279969	12.562288	12.550998	9.4611265	11.863777	12.130503
CO2	vol−%	4.9680091	3.8334094	3.7648715	4.8862848	3.8263325	3.8314816	5.0075866	3.7748955	3.6527578
H2O	vol−%	10.703877	8.977057	8.842954	9.6803755	7.8101054	7.8202434	12.551636	11.570435	11.334876
Ar	vol−%	0.88148	0.8839336	0.8845593	0.8903136	0.8947532	0.8947057	0.8645433	0.8592115	0.8602947
SO2	vol−%	0	0	0	0	0	0	0	0	0
N2	MW - 28 kg/kmol	20.587561	20.720297	20.73484	20.793656	20.973826	20.97272	20.19223	20.140871	20.166039
O2	MW - 32 kg/kmol	3.1742814	3.9374528	3.9854765	3.2895901	4.0199323	4.0163193	3.0275605	3.7964087	3.8817611
CO2	MW - 44 kg/kmol	2.185924	1.6867001	1.6565435	2.1499653	1.6835863	1.6858519	2.2033381	1.660954	1.6072134
H2O	MW - 18 kg/kmol	1.9266979	1.6158703	1.5917317	1.7424676	1.405819	1.4076438	2.2592944	2.0826783	2.0402777
Ar	MW - 39.95 kg/kmol	0.3521512	0.3531315	0.3533814	0.3556803	0.3574539	0.3574349	0.345385	0.343255	0.3436877
Exhaust MW	kg/kmol	28.226616	28.313451	28.321973	28.331359	28.440617	28.43997	28.027808	28.024167	28.038979
Ambient Conditions										
Air temperature	°F	59	59	59	20	20	20	90	90	90
Air humidity	%	60	60	60	30	30	30	60	60	60
Air pressure	psia	14.54	14.54	14.54	14.54	14.54	14.54	14.54	14.54	14.54
Air pressure	kPa	101.35	101.35	101.35	101.35	101.35	101.35	101.35	101.35	101.35
Universal Gas Constant	kJ/(kmol*K)	8.314	8.314	8.314	8.314	8.314	8.314	8.314	8.314	8.314
Operating Assumptions										
Duct burner status		on	off	off	on	off	off	on	off	off
Fuel LHV	Btu/lb	21136	21136	21136	21136	21136	21136	21136	21136	21136
Fuel HHV	Btu/lb	23274	23274	23274	23274	23274	23274	23274	23274	23274
Fuel S content (1hr avg)	gr/lb natural gas	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545
Fuel S content (3hr avg)	gr/lb natural gas	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545	0.4704545
Fuel S content (24hr avg)	gr/lb natural gas	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636	0.4338636
Fuel S content (ann avg)	gr/lb natural gas	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091	0.2384091
Fraction of SO2 converted to sulfate in exhaust	%	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333	33.333333
Fuel mass use rate	lb/hr	100271.55	76461.072	54764.63	105278.96	81363.56	57890.994	94068.703	70262.439	50925.861
CT heat input (HHV)	MMBtu/hr	1777.637	1779.555	1274.592	1894.1795	1893.6555	1347.355	1633.272	1635.288	1185.2485
DB heat input (HHV)	MMBtu/hr	556.08299	0	0	556.08299	0	0	556.08299	0	0
Total heat input (HHV)	MMBtu/hr	2333.72	1779.555	1274.592	2450.2625	1893.6555	1347.355	2189.355	1635.288	1185.2485

Natural Gas Sulfur Content

(Based on measurements taken between November 1, 2006 and September 30, 2008)

Averaging Period	1hr	3hr	24hr	Annual
Sulfur Content of NG - volume basis (ppmv)	35.6	35.6	32.8	18.0
Sulfur Content of NG - mass per volume (gr/100cf)	2.07	2.07	1.909	1.049
Higher Heating Value of NG (Btu/cf)		1024		
lb SO2/MMBtu	0.0058	0.0058	0.0053	0.0029
density of NG (lb/ft3)		0.044		
Sulfur Content of NG - mass basis (gr/lb)	0.470	0.470	0.434	0.238

Natural Gas Sulfur Content Data Sources

In order to determine SO_2 emissions from sources combusting natural gas (the CTs, duct burners, and auxiliary boiler), it was necessary to determine the maximum short-term average (hourly and daily) and long-term average sulfur contents of the pipeline natural gas. The natural gas pipeline delivers natural gas produced in British Columbia, Canada. Sulfur content data were collected from both the Canadian (Spectra Energy Transport) and the U.S. (Williams) pipeline companies responsible for delivering the fuel from the natural gas fields in northern British Columbia to Grays Harbor County in Washington.

Daily and annual average sulfur contents were calculated using data obtained from an analyzer operated by Williams in Sumas, Washington, as well as data provided by Spectra Energy Transport, obtained from their analyzer in Huntingdon, British Columbia. Daily average data from the Sumas analyzer covered the period from November 1, 2006 to October 31, 2007, and data from the Huntingdon analyzer covered the period from October 1, 2007 to September 30, 2008. The average daily sulfur concentration was 1.049 grains per 100 standard cubic feet of natural gas (gr/100 scf), which was used to calculate annual average SO_2 emission rates. The maximum daily average, 1.909 gr/100 scf was used to calculate maximum daily SO_2 emission rates.

Hourly data were obtained from the Sumas analyzer for the period from October 1, 2007 to September 30, 2008. Spectra provided 8-minute average data from the Huntingdon analyzer for periods where the Sumas data exhibited atypical short-term fluctuations in sulfur content. Where appropriate, the Spectra data were converted to hourly averages and substituted for the Sumas data. The maximum hourly average value was 2.07 gr/100 scf; this value was used to calculate both 1- and 3-hour average SO_2 emission rates.

Appendix A-3

Modeling Protocol

ENVIRON submitted an air quality modeling protocol on May 8, 2009. That protocol follows this introduction.

However, before the Federal Land Managers (FLMs) had responded to the protocol, two relevant documents were posted on EPA's SCRAM website[1] on May 27, 2009. They include a Clearinghouse memorandum on "CALPUFF modeling protocol for BART" (Fox 2009) and a draft "Reassessment of IWAQM Phase 2 Recommendations" (IWAQM 2009). These two documents changed the methodology for running CALMET, and spelled out a series of CALMET setting to be used for PSD air quality modeling analyses.

When the FLMs responded to the May 8 protocol, they asked us to comply with the May 27 guidance. ENVIRON developed a sample CALMET and CALPUFF input file that were accepted by the FLMs. In an email on July 8, 2009, EPA's Nancy Helm confirmed to EFSEC Siting Specialist Jim LaSpina that ENVIRON's CALMET input file of July 2, 2009 was acceptable, and that ENVIRON had federal clearance to begin modeling. That email is included below.

On August 31, 2009, another memo was posted on EPA's SCRAM website that again changed the methodology for running CALMET, and spelled out a different series of CALMET setting to be used for PSD analyses. These settings reversed the May 27 guidance, and use essentially the same settings as the VISTAS BART modeling protocol. Because the Grays Harbor Energy project had already received federal clearance to begin modeling on July 2, ENVIRON did not revise our modeling procedures to comply with the August 31 guidance.

The May 8 modeling protocol that follows has *not* been revised to account for the changes ENVIRON made to comply with the May 27 documents. Instead, we refer the reader to the CALMET and CALPUFF input files in the enclosed compact disk.

```
July 8, 2008 E-mail from Nancy Helm:

Jim,
That is correct. With NPS approval of this modeling protocol Environ
has
federal clearance to begin modeling. Also note John's second sentence:
In the future the FLMs will follow the revised EPA IWAQM guidance and
require MM5 data generated in the "hindcast" and not "forecast" mode.

Thanks, everyone, for your work on this.

Nancy Helm
Manager, Federal & Delegated Air Programs
US Environmental Protection Agency
1200 Sixth Avenue
Suite 900, AWT-107
Seattle, WA 98101
206 553-6908  fax 206 553-0110
```

[1] http://www.epa.gov/ttn/scram/

"LaSpina, Jim
(CTED)"
<JimLa@CTED.WA.GOV>

07/08/2009 02:51 PM

To
<John_Notar@nps.gov>, <Dee_Morse@nps.gov>, <tim_Allen@fws.gov>, Nancy Helm/R10/USEPA/US@EPA

cc
<rbur461@ECY.WA.GOV>, <cbow461@ECY.WA.GOV>, "Mark Goodin" <mark.goodin@orcaa.org>, "Eric Hansen" <ehansen@Environcorp.com>, <bbrashers@Environcorp.com>, <StephenP@CTED.WA.GOV>

Subject
Acceptance of June 16, 2009 Grays Harbor Energy Modeling Supplemental Protocol

Thank you all for your help on this matter in these regulatorily challenging times!

Since EPA deferred to NPS in this matter, I assume Environ has federal clearance to begin its modeling?

-----Original Message-----
From: John_Notar@nps.gov [mailto:John_Notar@nps.gov]
Sent: Wednesday, July 08, 2009 12:56 PM
To: LaSpina, Jim (CTED)
Cc: bbrashers@Environcorp.com; Dee_Morse@nps.gov; Eric Hansen; Posner, Stephen (CTED); tim_Allen@fws.gov; John_Notar@nps.gov; Bowman, Clint (ECY); John_Vimont@nps.gov
Subject: Re: Status of June 16, 2009 Grays Harbor Energy Modeling Supplemental Protocol?
Importance: High

Jim: the National Park Service accepts the version of the CALMET input file we received from Bart Brashers and ENVIRON on July 2, 2009 for the Grays Harbor project. In the future the FLMs will follow the revised EPA IWAQM guidance and require MM5 data generated in the "hindcast" and not "forecast" mode.
thanks
John Notar

John Notar
National Park Service
Air Resources Division
12795 W. Alameda Pkwy.
Lakewood, CO 80228
Phone: 303-969-2079
Fax: 303-969-2822
E-Mail: john_notar@nps.gov

"LaSpina, Jim (CTED)"

<JimLa@CTED.WA.GO
To
V> <John_Notar@nps.gov>, <Dee_Morse@nps.gov>, <tim_Allen@fws.gov>
07/07/2009 11:06 AM
cc
<bbrashers@Environcorp.com>, <StephenP@CTED.WA.GOV>, "Eric Hansen" <ehansen@Environcorp.com>

Subject
Status of June 16, 2009 Grays Harbor Energy Modeling Supplemental Protocol?

Hello John, Dee, Tim,

Please advise EFSEC as to the status of your review of Grays Harbor Energy's proposed air modeling materials/data that Environ recently submitted to you. They'd like to begin modeling ASAP.

If there is a holdup or problem with the materials, please inform EFSEC at your earliest convenience so that we can work with the applicant to address any deficiencies. Also, please inform us if there are any further concerns about the evolving federal air modeling policies.

Thanks very much for any clarification you can provide in this matter,
Jim La Spina EFSEC Siting Specialist

Modeling Protocol in Support of a Combined Notice of Construction and Prevention of Significant Deterioration Permit Application for Installation of Two Power Generation Units Modifying an Existing Major Stationary Source

Prepared for:
Grays Harbor Energy, LLC
Elma, Washington

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
May 8, 2009

Project Number:
29-22706A

ENVIRON

Contents

Contents (continued)

Appendices

Modeling Protocol in Support of a Combined Notice of Construction and Prevention of Significant Deterioration Permit Application for Installation of Two Power Generation Units Modifying an Existing Major Stationary Source

Grays Harbor Energy, LLC
Elma, Washington

1 Introduction

The Grays Harbor Energy Center, owned and operated by Grays Harbor Energy LLC, currently consists of two combined-cycle combustion turbines and a steam turbine generator with a nominal electrical generation capacity of 530 megawatts (MW) and a peak output of 650 MW. Grays Harbor Energy. LLC (GHE) proposes to add two similar combustion turbines and a steam turbine (referred to as Units 3 and 4), effectively doubling the maximum generation potential of the facility. GHE is a wholly-owned subsidiary of Invenergy Thermal, LLC. Washington's Energy Facility Site Evaluation Council (EFSEC) has jurisdiction over the approval of the requested modification.

This air quality dispersion modeling protocol was prepared by ENVIRON International Corporation (ENVIRON) on behalf of GHE as a preliminary step in preparing the air quality permit application needed to modify the Grays Harbor Energy Center. The permit application will be included as part of the Request for Amendment of the Site Certification Agreement to be submitted to EFSEC.

This modeling protocol identifies how the combined Notice of Construction and Prevention of Significant Deterioration (PSD) permit application (hereafter simply referred to as the PSD application) will evaluate compliance with applicable ambient air quality standards, PSD increments, air quality related values, and toxic air pollutant criteria. A modeling protocol provides interested parties an opportunity to review the proposed procedures with the objective of reaching consensus on the approach in advance of the actual analysis. This protocol will describe the proposed modification, summarize the parameters used to represent emission sources in the simulations, discuss the selection of the dispersion models used in the analyses as well as model inputs and options, and present the approach used to prepare the meteorological data.

ENVIRON and GHE acknowledge that a modeling protocol dated June 23, 2008 was previously submitted by Cascade Environmental Management. That protocol was reviewed by the Olympic Region Clean Air Agency (ORCAA), the U.S. Environmental Protection Agency (USEPA), and federal land managers (FLMs). In January 2009, ENVIRON was retained to replace Cascade Environmental Management in preparing the air quality sections of the SCA Amendment Request to EFSEC. ENVIRON reviewed written comments on the 2008 protocol and, where appropriate, has addressed them in this revised modeling protocol. In some cases, the comments directed certain issues to be addressed in the permit application rather than the modeling protocol, and those comments will be addressed in the EFSEC submittal.

The primary difference between this protocol and the initial protocol is that ENVIRON believes this modification should be evaluated as a modification to an existing major stationary source. We acknowledge that a previous owner, Duke Energy, filed a request in 2001 to amend its Site Certification Agreement authorizing construction of two additional combined cycle units, what Duke referred to as "Phase 2.". Duke's proposal was to allow two separate and individually-financed power plants (each consisting of two combustion turbines with one steam turbine in a 2-on-1 configuration) on the same site. A PSD permit application for the second plant was included in the request as Section 6.1 of the Application for Amendment to the Site Certification Agreement. We acknowledge that Duke's proposal was very similar to what is being proposed now by GHE.

Less than a year later, however, Duke Energy requested that EFSEC postpone its review of the proposed amendment, and never asked EFSEC to resume processing of the amendment request. Although construction of the two-unit project began in September 2001, it was suspended in September 2002 with the project roughly 56 percent completed.

Invenergy purchased the partially completed project in 2005 and re-started construction in 2007. The facility became operational in April 2008. Today, EFSEC's web site characterizes the Grays Harbor Energy facility as follows:

> *"The Satsop Combustion Turbine Project consists of two combustion turbine generators on a "two on one" configuration with a single steam turbine generator. The Project will produce a nominal output of approximately 530 megawatts per year, with a maximum annual output of approximately 650 megawatts. The Project is a 20-acre site within the Satsop Redevelopment Park in Grays Harbor County. The entire 20-acre site was previously developed, including grading and surfacing with gravel and asphalt, and used as an equipment and material laydown area during construction of WNP-3 and WNP-5.*
>
> *The Site Certification Agreement for the Satsop Nuclear Project (WNP 3/5) site was amended in 1996 to allow for construction of a 450 MW gas turbine. The nuclear power projects were removed from the Site Certificate in 1999. In April, 2001 the Site Certificate was amended again to allow the current 650 MW gas turbine project. Construction started on the combustion turbine project in September 2001 but was suspended in September 2002 at approximately 56% complete.*
>
> *In April 2005 the Site Certification Agreement was amended to reflect the sale of the project to Grays Harbor Energy LLC (a subsidiary of Invenergy Inc.) from Duke Energy. Construction was restarted in February 2007 with commercial operation starting in April 25, 2008."*

The existing EFSEC approval is for two combustion turbines; a four turbine project has never been approved. We acknowledge that a previous owner of a partially completed project proposed what it called a second "phase" in November of 2001, during the peak of a major energy crisis, but the project application was placed on hold and never acted on. Four years later, GHE purchased a partially constructed facility designed and approved for two units. The four combustion turbine proposal in 2001 was four years prior to any involvement by GHE. In February 2005, GHE purchased a partially constructed two combustion turbine plant with the intent to complete the construction and make the plant operational, which it achieved in April 2008.

The proposed addition of Units 3 and 4 triggers PSD review because the addition constitutes a modification of the existing source that increases annual emissions by amounts that exceed the Significant Emission Rates established in the PSD program. Our position that the modification is the addition of two combustion turbines to an existing major source does not circumvent the PSD process. Rather, presenting our proposal in this manner more clearly characterizes what is actually happening at an existing, operating power plant.

ENVIRON presents a modeling protocol that is consistent with how major modifications to existing major stationary sources are evaluated in the PSD permit process. However, because both EFSEC and USEPA have expressed an interest in understanding how emissions from all four combustion turbines will affect air quality in Class I areas, this protocol also addresses how the cumulative effects of those emissions will be evaluated.[1]

[1] ENVIRON discussed and reached agreement for this approach with EFSEC (Robert Burmark, Jim LaSpina, and Stephen Posner) and with EPA (Nancy Helms) in mid-April 2009.

2 Modification Description

2.1 Physical Description

2.1.1 Location

The Grays Harbor Energy Center facility is located in the Chehalis River Valley approximately 6 kilometers (km) or 4 miles south-southwest of Elma, Washington, at 123° 28' 44" West longitude and 46° 58' 8" North latitude. The Chehalis River Valley is a narrow plain between the Olympic Mountains to the north and the Willapa Hills to the south. Figure 2-1 displays the topography in the vicinity of the facility and the location of the near-field analysis modeling domain.

The Grays Harbor Energy Center is in Grays Harbor County, which is designated as attainment or unclassifiable for all criteria pollutants, and is located in Universal Transverse Mercator (UTM) Zone 10.

2.1.2 Equipment Description

The proposed modification consists of the following equipment:

- Two General Electric GE 7FA combustion turbines each with a nominal maximum heat input rating of between 1,735 and 1,780 million British thermal units per hour (MMBtu/hr), depending on the unit selected, and each yoked to an electrical generator with a nominal gross output of 175 MW;
- One heat recovery steam generator (HRSG) and supplementary duct burner per turbine (each with a nominal maximum heat input rate of 505 MMBtu/hr);
- One steam turbine generator (STG) unit with a nominal gross output rating of 300 MW, powered by steam produced in the HRSGs;
- One natural gas-fired auxiliary boiler with a nominal heat input rating of less than 30 MMBtu/hr;
- One forced draft/evaporative cooling tower;
- One emergency diesel engine generator; and
- One diesel engine emergency fire water pump.

2.2 Short-Term Normal Operation Emission Rates

In order to determine the potential air quality impacts associated with a major source modification such as that proposed by GHE and the regulations that would apply to the modification, the types and quantities of emitted air pollutants must be identified. Pollutant emissions are determined by the physical and operational characteristics of the facility. The pollutant emission rates presented in this protocol are based on preliminary assumptions and equipment specifications, and may change before the permit application is submitted.

2.2.1 Power Generation Units

The two proposed combustion turbine generators (CTGs) and duct burners would combust only natural gas. The hot exhaust gases exiting the CTG 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 HRSG to generate high-energy steam that is used to produce additional electricity in the STG. Steam generated by the HRSG may be supported by duct burners depending upon the situation. Following heat recovery, the cooled CTG exhaust gas is discharged to the atmosphere through the HRSG stacks. Selective catalytic reduction (SCR) control equipment for removal of oxides of nitrogen (NO_X) emissions and an oxidation catalyst for control of carbon monoxide (CO) and volatile organic compounds (VOCs) would be located within the HRSG.

To evaluate air quality implications of the range of operating conditions, we will examine four potential operating modes:

1) 100 percent combustion turbine load with duct burners

2) 100 percent combustion turbine load without duct burners

3) 60 percent combustion turbine load without duct burners

4) Combustion turbine startup/shutdown

Table 2-1 presents short-term emission rates for each combustion turbine operating mode. Although operation with duct burners typically produces the highest overall facility emissions, the modeling analyses will consider all three scenarios because predicted ground level concentrations are affected by exhaust gas characteristics (flow rate and temperature) as well as emission rates.

Table 2-1. Preliminary Combustion Turbine Short-Term Emission Rates

Operating Mode	NO_x[1]	CO[1]	SO_2[1,2] (1&3-hr)	SO_2[1,3] (24-hr)	PM_{10}[1,4]	VOC[1]
100% load w/duct firing	20.0	12.2	14.2	13.1	19.0	3.48
100% load	15.9	9.7	10.9	5.0	19.0	2.76
60% load	11.3	6.9	7.8	3.6	19.0	5.88
Maximum	20.0	12.2	14.2	13.1	19.0	5.88

[1] Pounds per hour per combustion turbine/HRSG unit. Values represent worst-case emission rates from performance data developed for three ambient temperature/relative humidity scenarios (20 °F/30%, 59 °F/60%, and 90 °F/60%)

[2] Based on a maximum hourly average sulfur content of 2.07 gr/100 scf of natural gas, which is based on sulfur content data provided by the natural gas supplier collected between October 1, 2007 and September 30, 2008.

[3] Based on a maximum daily average sulfur content of 1.91 gr/100 scf of natural gas, which is based on sulfur content data provided by the natural gas supplier collected between November 1, 2006 and September 30, 2008.

[4] Filterable $PM_{2.5}$ emissions are equal to the filterable portion of PM_{10} emissions, which was assumed to be 25 percent of total PM_{10} emissions, consistent with guidance found at http://www.nature.nps.gov/air/permits/ect/ectGasFiredCT.cfm

NO_X and CO emissions are based on proposed emission limits of 2 parts per million by volume, dry (ppmvd) at 15 percent O_2, 3-hour and 1-hour averages, respectively. SO_2 emissions are based on mass balance calculations using the concentration of sulfur in the natural gas passing through Williams Northwest Pipeline Sumas station in Washington. Recent data (from the 4th quarter of 2007 through the 3rd quarter of 2008) reveal 24-hour, 3-hour, and 1-hour levels of 2.13, 2.34, and 2.36 grains sulfur per 100 cubic feet (gr/100 cf) , respectively, based on the 99th percentile sulfur concentration for those averaging periods. The annual average concentration during the same measurement period was 1.07 gr/100 cf. Particulate matter (PM) and VOC emissions are based on data provided by GE.

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

Table 2-2 identifies TAPs expected to be emitted by the combustion turbines based on emission factors from Section 3.1 of USEPA’s AP-42 emission factor document (Stationary Gas Turbines). Emission factors in Section 1.4 (Natural Gas Combustion) of AP-42 were used to estimate duct burner TAP and HAP emission rates. Ammonia slip emissions are based on a proposed permit limit of 5 ppmvd at 15 percent O_2. Sulfuric acid (H_2SO_4) emissions were based on an assumed 33 percent conversion of SO_2. Table 2-2 presents the maximum total TAP and HAP emissions from a single combustion turbine under full load operation with duct burning.

Table 2-2. Combustion Turbine TAP & HAP Emission Rates[1]

Compound	CAS #	Emission Factors		Maximum Emission Rate	
		CT (lb/MMBtu)	Duct Burner (lb/MMscf)	(lb/hr)	(ton/yr)
Acetaldehyde	75-07-0	0.00004	--	0.0758	0.332
Acrolein	107-02-8	0.0000064	--	0.0121	0.0531
Ammonia	7664-41-7	0.009064627	--	17.2	75.2
Arsenic	7440-38-2	--	0.0002	0.000109	0.000476
Barium	7440-39-3	--	0.0044	0.00239	0.0105
Benzene	71-43-2	0.000012	0.0021	0.0239	0.105
Beryllium	7440-41-7	--	0.000012	0.00000652	0.0000285
1,3-Butadiene	106-99-0	0.00000043	--	0.000814	0.00357
Butane	106-97-8	--	2.1	1.14	4.99
Cadmium	7440-43-9	--	0.0011	0.000597	0.00262
Chromium, total	7440-47-3	--	0.0014	0.00076	0.00333
Chromium, hexavalent	18540-29-9	--	0.0007	0.00038	0.00166
Cobalt	7440-48-4	--	0.000084	0.0000456	0.0002
Copper	7440-50-8	--	0.00085	0.000462	0.00202
Ethylbenzene	100-41-4	0.000032	--	0.0606	0.265
Formaldehyde[1]	50-00-0	0.0001065	0.01125	0.208	0.91
Hexane	110-54-3	--	1.8	0.977	4.28
Manganese	7439-96-5	--	0.00038	0.000206	0.000904
Mercury	7439-97-6	--	0.00026	0.000141	0.000618
Molybdenum	7439-98-7	--	0.0011	0.000597	0.00262
Naphthalene	91-20-3	0.0000013	0.00061	0.00279	0.0122
Nickel	7440-02-0	--	0.0021	0.00114	0.00499
Pentane	109-66-0	--	2.6	1.41	6.18
Polyaromatic Hydrocarbons	PAH	0.0000022	0.0000096	0.00417	0.0183
Polycyclic Organic Matter	POM	0.0000022	0.0000882	0.00422	0.0185
Propylene Oxide	75-56-9	0.000029	--	0.0549	0.241
Selenium	7784-49-2	--	0.000024	0.000013	0.0000571
Sulfuric Acid	7664-93-9	--	--	3.9	17.1
Toluene	108-88-3	0.00013	0.0034	0.248	1.09
Vanadium	7440-62-2	--	0.0023	0.00125	0.00547
Xylenes	1330-20-7	0.000064	--	0.121	0.531

[1] The formaldehyde emission factors were reduced by 85% to reflect control provided by the oxidation catalyst. See page 7 of AP-42 Section 3.1.

2.2.2 Auxiliary Boiler

The auxiliary boiler will combust only natural gas and will be used to generate steam to reduce the duration of the startup period for the CTGs and STG. Although the boiler is unlikely to operate when a combustion turbine is operating, the modeling of the continuous operation "base load" scenario includes boiler emissions for a 24-hour period. Criteria pollutant emissions summarized in Table 2-3 are based on the use of ultra-low-NO_X burners to achieve 9 ppmvd NO_X at 3 percent O_2, and good combustion control to achieve 50 ppmvd CO at 3 percent O_2.

SO_2 emissions are based on a mass balance calculation similar to that use to calculate emissions from the CTGs. PM_{10} and VOC emissions are based on factors from Section 1.4 of AP-42.

Table 2-3. Auxiliary Boiler Criteria Pollutant Emission Rates

Pollutant	Emission Factor (lb/MMBtu)	Short-Term Emission Rate (lb/hr)	Annual Emission Rate[1] (ton/yr)
NO_x	0.011	0.3223	4.60E-05
CO	0.037	1.0841	1.55E-04
SO_2[2]	0.0066	0.192925	--
	0.0065	0.19129	--
	0.0059	0.174123	--
	0.0030	--	1.25E-05
PM_{10}[3]	0.005	0.1465	2.09E-05
VOC	0.004	0.1172	1.67E-05

[1] Based on 2,500 hours of operation per year

[2] Assumed natural gas sulfur contents in grains per 100 standard cubic feet: 2.36 (1-hr average), 2.34 (3-hr average, and 2.13 (24-hr average)

[3] $PM_{2.5}$ emissions are assumed to be equal to the filterable portion of PM_{10} emissions which is based on the fraction provided in USEPA's AP-42 Section 1.4.

Auxiliary boiler TAP emissions were calculated based on natural gas-fired boiler emission factors from Section 1.4 of AP-42 and the maximum rated boiler heat input (29.3 MMBtu/hr). Maximum annual emissions were based on a maximum of 2,500 hours of operation per year. Table 2-4 presents the TAP and HAP emissions for the auxiliary boiler.

Table 2-4. Auxiliary Boiler TAP & HAP Emission Rates

Compound	CAS #	Emission Factor (lb/MMscf)	Short-Term Emission Rate (lb/hr)	Annual Emission Rate[1] (ton/yr)
Arsenic	7440-38-2	2.00E-04	5.72E-06	7.15E-06
Barium	7440-39-3	4.40E-03	1.26E-04	1.57E-04
Benzene	71-43-2	2.10E-03	6.01E-05	7.51E-05
Beryllium	7440-41-7	1.20E-05	3.43E-07	4.29E-07
Butane	106-97-8	2.10E+00	6.01E-02	7.51E-02
Cadmium	7440-43-9	1.10E-03	3.15E-05	3.93E-05
Chromium, Total	7440-47-3	1.40E-03	4.01E-05	5.01E-05
Chromium, Hexavalent	18540-29-9	7.00E-04	2.00E-05	2.50E-05
Cobalt	7440-48-4	8.40E-05	2.40E-06	3.00E-06
Copper	7440-50-8	8.50E-04	2.43E-05	3.04E-05
Formaldehyde	7440-47-3	7.50E-02	2.15E-03	2.68E-03
Hexane	110-54-3	1.80E+00	5.15E-02	6.44E-02
Manganese	7439-96-5	3.80E-04	1.09E-05	1.36E-05
Mercury	7439-97-6	2.60E-04	7.44E-06	9.30E-06
Molybdenum	7439-98-7	1.10E-03	3.15E-05	3.93E-05
Naphthalene	91-20-3	6.10E-04	1.75E-05	2.18E-05

Compound	CAS #	Emission Factor (lb/MMscf)	Short-Term Emission Rate (lb/hr)	Annual Emission Rate[1] (ton/yr)
Nickel	7440-02-0	2.10E-03	6.01E-05	7.51E-05
Pentane	109-66-0	2.60E+00	7.44E-02	9.30E-02
Polyaromatic Hydrocarbons	PAH	9.60E-06	2.75E-07	3.43E-07
Polycyclic Organic Matter	POM	8.82E-05	2.52E-06	3.15E-06
Selenium	7784-49-2	2.40E-05	6.87E-07	8.58E-07
Toluene	108-88-3	3.40E-03	9.73E-05	1.22E-04
Vanadium	7440-62-2	2.30E-03	6.58E-05	8.23E-05

[1] Based on 2,500 hours of operation per year

2.2.3 Emergency Diesel Engines

Diesel-fueled engines will be used to provide emergency power and pressurized water for fire protection during a power outage. The engines will meet the emission standards prescribed by 40 CFR Part 60 Subpart IIII (Standards of Performance for Stationary Compression Ignition Internal Combustion Engines). Ordinarily, the engine will operate only a few hours per month for testing, and Subpart IIII limits non-emergency operation to 100 hours per year. In the modeling analyses, it is assumed that the engine is tested in the one hour scenario, but operates only one hour in the 3-hour, 8-hour, and 24-operating scenarios. Annual emissions are estimated based on 100 hours of operation over the course of a year. Hourly and annual criteria pollutant emissions are presented in Table 2-5.

Table 2-5. Emergency Diesel Engine Criteria Pollutant Emission Rates

Emergency Generator	Units	NO_x[1]	CO	SO_2[2]	PM_{10}[3]	VOC[1]
Emission Factor[4]	g/kW-hr	4.0	3.5	0.0074	0.20	4.0
	lb/hp-hr	0.0066	0.0058	0.000012	0.00033	0.0066
Emission Rate	lb/hr	3.95	3.45	0.00728	0.197	3.95
	ton/yr[5]	0.197	0.173	0.000364	0.00987	0.197
Emergency Fire Water Pump	**Units**	**NO_x[1]**	**CO**	**SO_2[2]**	**PM_{10}[3]**	**VOC[1]**
Emission Factor[4]	g/kW-hr	3.0	2.6	0.0074	0.15	3.0
	lb/hp-hr	0.0049	0.0043	0.000012	0.00066	0.0049
Emission Rate	lb/hr	1.36	1.18	0.00334	0.181	1.36
	ton/yr[5]	0.0678	0.0588	0.000167	0.00905	0.0678

[1] Conservatively assumed both NO_X and VOC emissions equal the Subpart IIII limit on the sum of NO_X and VOC emissions.

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

[3] $PM_{2.5}$ emissions are equal to the filterable portion of PM_{10}, which was calculated using a ratio of emission factors from Table 3.4-2 in USEPA's AP-42, Section 3.4.

[4] 40 CFR Part 60.4202(a)(2) Subpart IIII (except SO_2, see note 2)

[5] Based on 100 hours per year of maintenance operation per engine.

The emergency diesel engine TAP and HAP emission rates presented in Table 2-6 were calculated based on the emission standards in Subpart IIII. Maximum annual emissions were based on the 100 hour per year limit of non-emergency operation imposed by Subpart IIII.

Table 2-6. Emergency Diesel Engine TAP & HAP Emission Rates

Compound	CAS #	Emission Factor[1] (lb/MMBtu)	Emergency Generator		Fire Water Pump	
			Short-term (lb/hr)	Annual[2] (ton/yr)	Short-term (lb/hr)	Annual[2] (ton/yr)
Acetaldehyde	75-07-0	7.67E-04	1.17E-03	5.85E-05	5.37E-04	2.68E-05
Acrolein	107-02-8	9.25E-05	1.41E-04	7.06E-06	6.47E-05	3.24E-06
Benzene	71-43-2	9.33E-04	1.42E-03	7.12E-05	6.53E-04	3.26E-05
1,3-Butadiene	106-99-0	3.91E-05	5.97E-05	2.98E-06	2.74E-05	1.37E-06
Formaldehyde	50-00-0	1.18E-03	1.80E-03	9.00E-05	8.26E-04	4.13E-05
Naphthalene	91-20-3	8.48E-05	1.29E-04	6.47E-06	5.93E-05	2.97E-06
Propylene	115-07-1	2.58E-04	3.94E-04	1.97E-05	1.80E-04	9.02E-06
Polyaromatic Hydrocarbons[3]	PAH	4.51E-06	6.88E-06	3.44E-07	2.29E-06	1.15E-07
Polycyclic Organic Matter[4]	POM	8.31E-05	1.27E-04	6.34E-06	5.83E-05	2.91E-06
Toluene	108-88-3	4.09E-04	6.24E-04	3.12E-05	2.86E-04	1.43E-05
Xylenes	1330-20-7	2.85E-04	4.35E-04	2.17E-05	1.99E-04	9.97E-06

1 Emission factors from USEPA AP-42 Section 3.3 Small Diesel Engines (<600hp)

2 Maximum annual emission based on 100 hr/yr normal maintenance operation per engine.

3 Washington State PAHs determined by WAC 173-460-50

4 For the CAA112 requirements, all Polyaromatic Hydrocarbons (PAH) will be considered Polycylic Organic Matter (POM)

2.2.4 Cooling Towers

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

The cooling tower is configured in two parallel sets of 5 cells. The quantity of water released as droplets to the air (the drift rate) is based on 0.0005 percent of the water recirculation rate, and reflects the use of very high efficiency drift eliminators. The total dissolved solids (TDS) content of the drift is the maximum value estimated from local water quality measurement data water concentrated 12 times by the water recirculation cycles. PM emissions from the cooling tower displayed in Table 2-7 are based on the assumption that water throughput is maximized in all cooling tower cells. The cooling towers are not expected to emit any TAPs.

Table 2-7. Cooling Tower Particulate Matter Emission Rates

Parameter	Units	Value
Water circulation rate	MMlb/hr	87.6
Maximum dissolved solids[1]	ppmw	1,800
Drift as fraction of circulating water	%	0.0005
Short-term PM_{10} emission rate[2,4]	lb/hr	0.79
Annual PM_{10} emission rate[3,4]	ton/yr	3.5

[1] Maximum expected total dissolved solids (TDS) in makeup water = 150 parts per million by weight (ppmw); maximum expected TDS in circulating cooling water at twelve cycles = 12 x 150 = 1800 ppmw

[2] Example calculation: (87.6 x 10^6 lb/hr) x (0.000005 lb drift/lb water) x (1800 lb PM/10^6 lb drift) = 0.79 lb/hr

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

[4] $PM_{2.5}$ emissions are equal to filterable PM_{10} emissions, which were assumed to be 100 percent of total PM_{10} emissions.

2.2.5 Short-Term Emission Rate Summary

Short-term maximum criteria pollutant emission rates for operation are summarized in Table 2-8. This table presents emissions for three combustion turbines operating scenarios, and maximum operation for the cooling tower, auxiliary boiler, and emergency diesel engines. In practice, it is unlikely that these units would all operate simultaneously at their maximum capacity.

Table 2-8. Maximum Proposed Short-Term Criteria Pollutant Emission Rate Increases[1]

Source	NO_X	CO	SO_2	PM_{10}	$PM_{2.5}$[2]	VOC
Combustion Turbines w/Duct Firing[3]	40.0	24.4	28.3	38.0	9.5	7.0
Combustion Turbines @ 100% Load[3]	31.7	19.3	21.9	38.0	9.5	5.5
Combustion Turbines @ 60% Load[3]	22.5	13.7	15.6	38.0	9.5	11.8
Auxiliary Boiler	0.32	1.1	0.17	0.15	0.04	0.12
Emergency Diesel Generator	0.16	3.5	0.0073	0.0082	0.0069	3.9
Emergency Diesel Fire Pump	0.057	1.2	0.0033	0.0075	0.0063	1.4
Cooling Tower	--	--	--	0.8	0.8	--
100% Load w/Duct Firing Total	40.6	30.1	28.5	39.0	10.3	12.4
100% Load Total	32.3	25.0	22.1	39.0	10.3	10.9
60% Load Total	23.1	19.4	15.7	39.0	10.3	17.2
Worst Case Total	40.6	30.1	28.5	39.0	10.3	17.2

[1] All emission rates are in pounds per hour, averaged over one hour.

[2] Filterable $PM_{2.5}$.

[3] Combined emission rate for both units.

2.3 Annual Average Normal Operation Emission Rates

Annual emissions (typically expressed as tons per year or tpy) depend on how many hours each unit operates and the unit's operating rate during those periods. Table 2-9 presents annual emissions assuming the combustion turbines operate every hour of the year in the operating mode with the highest emission rates; these occur when the CTGs are operating at 100 percent load with duct burners for all pollutants except VOCs, which are highest when the CTGs operate at 60 percent load. In consideration of the potential operating mode with frequent startups and shutdowns, annual average emission rates that incorporate a daily startup/operation/shutdown sequence will be developed.

Table 2-9. Criteria Pollutant Annual Emission Rates for Continuous Operation

Source	NO_X[1]	CO[1]	SO_2[1]	PM_{10}[1]	VOC[1]
Combustion Turbines[2] w/Duct Firing	175	107	64.1	144	30.5
Combustion Turbines @ 100% Load[2]	139	84.6	24.8	127	24.2
Combustion Turbines[2] @ 60% Load	98.8	60.1	17.6	90.5	51.5
Auxiliary Boiler[3]	0.40	1.4	0.24	0.18	0.15
Emergency Diesel Generator[4]	0.0082	0.17	0.00036	0.00041	0.20
Emergency Diesel Fire Pump[4]	0.0028	0.059	0.00017	0.00038	0.068
Cooling Towers[5]	--	--	--	7.7	--
100% Load w/Duct Firing Total	176	108	64.3	152	30.9
100% Load Total	139	86	25.0	135	24.6
60% Load Total	99	61.7	17.9	98.4	51.9
Maximum Facility-wide Emissions	176	108	64.3	152	51.9

[1] Emission rates are in tons per year

[2] Combined emission rates for both units

[3] 2,500 hours per year

[4] Maximum of 100 hours per year of maintenance/testing operation

[5] Total for 10 cooling tower cells

Auxiliary boiler emissions are based on full load operation for 2,500 hours per year. Although GHE intends to test the emergency diesel engines only a few hours per month, the annual emission scenario assumes it is operated 100 hours per year at its maximum capacity rating. Annual PM_{10} emissions from the cooling towers are based on the assumption that the water flow rate is maximized in each cell every hour of the year. In practice, water flow may be reduced as outdoor temperatures drop or when the combustion turbine load decrease. Consequently, this assumption provides a conservative estimate of cooling tower emissions.

2.4 Startup Emission Rates

Emissions of some pollutants are 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 automobile engines, combustion turbines emit more carbon monoxide during startup because combustion is optimized for a warm engine and the typical higher loads (usually 60 percent load or greater). Combustion turbine NO_X emissions are also higher during startup, in part because the SCR is not effective at low exhaust gas temperatures.

The duration of a combustion turbine startup event and the total pollutant emissions from the event depend on the extent of the downtime preceding the event. Startup times and emissions provided by the turbine manufacturer are shown in Table 2-10. Modeling simulations will be developed for cases where a pollutant emission rate exceeds that of one of the normal operating scenarios. Because stack parameters vary throughout a startup or shutdown event, modeling simulations were developed using stack parameters from every available operating scenario. In all cases, the operational scenario that generates maximum pollutant emissions will be assume for the balance of the averaging periods (in all cases, this is 100 percent load with duct firing). At this point, only the short-term NO_X and CO emission rates exceed the corresponding normal operation emission rates. For both the 1- and 8-hour average CO concentrations, emissions based on a warm start followed by normal operation will be included in the startup modeling simulation. Because there is no short-term ambient NO_X standard, no short-term NO_X startup modeling will be developed.[2]

Table 2-10. Combustion Turbine Startup and Shutdown Duration and Emission Rates

Mode[1]	Time[2] (min)	Emissions per Event[3] (lb)							
		NO$_X$	CO	SO_2[4]				PM$_{10}$	VOC
				(1-hr)	(3-hr)	(24-hr)	(Annual)		
Cold Start	241	520	1,300	7.3	22.0	20.3	11.0	50	80
Warm Start	124	275	1,900	6.4	13.2	12.2	6.6	30	120
Hot Start	83	175	800	5.5	10.1	9.3	5.1	20	60
Shutdown	30	100	650	7.7	3.8	3.5	1.9	8	40

[1] Startup mode definitions: Cold Start is more than 72 hours since shutdown, Warm Start is approximately 48 hours since shutdown, and Cold Start is less than 8 hours since shutdown.

[2] Time for both turbines to reach 100 % load for startup (first turbine will reach 100% load 20-30 minutes before the second), and to go from 100% load to no operation for shutdown.

[3] Emissions are for both turbines, combined.

[4] SO_2 emissions were not provided by the turbine manufacturer. Based on analysis of continuous emissions monitor system (CEMS) data collected from the existing Units 1 & 2 during startup and shutdown events, it was estimated that the average emission rate during a cold start event is approximately 50% of hourly 100% load normal operation emission rate, 58.5% during a warm start event, 67% during a hot start event, and 70% during shutdown.

[2] The 24-hour average NO_X emission rate reflecting startup and shutdown emissions will be included in the worst-case AQRV analysis of visibility impacts.

Annual average NO_X, SO_2, and PM_{10} emission rates (filterable $PM_{2.5}$ was assumed to be 25 percent of PM_{10}) reflecting startup and shutdown emission rates have been developed for three startup scenarios: cold startup, warm startup, and hot startup. The normal operation annual average emission rates assume no startups or shutdowns; to bound the universe of reasonable possibilities each of the three startup scenarios was assumed to occur as often as possible, followed by 16 hours of operation (100 percent load with duct firing), and a shutdown. The cycle starts again following the minimum amount of non-operational time prior to startup that defines the scenario (i.e., 72 hours for cold start, 10 hours for warm start, and 0 hours for hot start) and repeats throughout the year. At this point, preliminary emission rate calculations indicate that only annual average NO_X exceeds the corresponding normal operation emission rate.

2.5 Unit 1, Unit 2, and Related Source Emission Rates

The discussion above described emissions from sources related to the proposed new Unit 3 and Unit 4. In addition to air quality simulations with these sources, EFSEC and USEPA requested that potential air quality impacts to Class I areas also include emissions from the existing facility (referred to as Unit 1 and Unit 2). PSD regulations do not require these cumulative impact simulations to assess the ambient standards and/or the PSD increments unless screening criteria are exceeded due to emissions from the new sources. However, at the request of USEPA and EFSEC, simulations will be performed with both existing and proposed GHEC sources to provide data to the Federal Land Managers even if the screening criteria are not exceeded. Table 2-10 and Table 2-11 show the maximum permitted daily and annual emissions from the existing Unit 1 and Unit 2 sources that will be used in the simulations for Class I areas.

Table 2-10. Maximum Permitted Unit 1, Unit 2, and Related Source Daily Emission Rates[1]

Source	NO_X	SO_2	PM_{10}
Combustion Turbines w/Duct Firing[2]	34.8	39.6	45.2
Auxiliary Boiler	1.03	0.07	0.29
Emergency Diesel Generator[3]	7.05	0.27	0.11
Emergency Diesel Fire Pump[4]	4.2	0.11	0.24
Cooling Towers	--	--	1.02

[1] All emission rates are in pounds per hour.

[2] Combined emission rate for both units.

[3] Emergency generator emissions based on 500 kilowatt (kW) engine rating, but actual nameplate is 400 kW. Emergency generator NOX emission rates include NOX and NMOC (as limited by 40 CFR 89.112)

[4] Fire water pump emissions based on 205 kW engine rating (275 hp) and corresponding emission factors from 40 CFR 89.112 (2002 engine). SO_2 emissions based on AP-42 section 3.4, Table 3.4-1 and sulfur content of 0.05 percent by weight.

Table 2-11. Maximum Permitted Unit 1, Unit 2, and Related Source Annual Emission Rates[1]

Source	NO_X	SO_2[2]	PM_{10}
Combustion Turbines w/Duct Firing[3]	243.4	58.0	198.0
Auxiliary Boiler	1.3	0.106	0.4
Emergency Diesel Generator[4]	1.76	0.07	0.06
Emergency Diesel Fire Pump[5]	1.04	0.028	0.061
Cooling Towers	--	--	4.5

[1] All emission rates are in tons per year.

[2] Based on recent sulfur analysis of pipeline natural gas in the Pacific Northwest, annual average SO_2 emissions from the combustion turbines, duct burners, and auxiliary boiler will be based on a gas sulfur content of 1.0 gr/100 scf, rather than the 0.5 gr/100 scf that was assumed when the current annual permit limits were calculated.

[3] Combined emission rate for both units.

[4] Emergency generator emissions based on 500 kilowatt (kW) engine rating, but actual nameplate is 400 kW. Emergency generator NOX emission rates include NOX and NMOC (as limited by 40 CFR 89.112)

[5] Fire water pump emissions based on 205 kW engine rating (275 hp) and corresponding emission factors from 40 CFR 89.112 (2002 engine). SO_2 emissions based on AP-42 section 3.4, Table 3.4-1 and sulfur content of 0.05 percent by weight. Annual emissions based on 500 hours of operation per year.

3 Air Quality Impact Analysis Methodology

3.1 Model Selection

As of November 9, 2005, AERMOD became the model recommended by the USEPA's *Guideline on Air Quality Models* (codified as Appendix W to 40 CFR Part 51) as the preferred dispersion model for complex source configurations and for sources subject to building downwash. The latest version of the USEPA regulatory model AERMOD (Version 07026) will be used for the dispersion modeling analysis.

3.2 Model Input Data

3.2.1 Emission Rates

The short-term and annual emission rates calculated for modification sources as described in the previous section will be included in the modeling simulations. Simulations will be developed for four operating power generation unit scenarios (100 percent load with duct firing, 100 percent load, 60 percent load, and startup/shutdown). In addition, emission rates for each of the four scenarios at three different ambient temperature and relative humidity combinations (20 °F/30%, 59 °F/60%, and 90 °F/60%) will be modeled. If facility-wide modeling becomes necessary to assess compliance with ambient standards and increments in the area surrounding the facility, the emission rates summarized in Table 2-10 and Table 2-11 will be used for existing sources at the facility.

3.2.2 Elevation Data and Receptor Network

Several receptor grids will be used in the dispersion modeling simulations. The modeling domain shown in Figure 3-1 is 10 km-by-10 km. Initially, receptors will be placed 500 meters apart covering the entire modeling domain, with a 50 km-by-50 km nested receptor grid with 200 m spacing, and a 2 km-by-2 km nested grid with 50-m spacing. The nested grids will be located such that Grays Harbor Energy Center is the center of each grid, and receptors will be located at 25-m intervals along the fenceline of the facility. Nested 25-m spacing grids will be placed around the locations of the initially-predicted maximum concentrations to more fully resolve the magnitude and location of the predicted maximum concentration.

Terrain elevations and hill height scale values for the receptors shown in Figure 3-1 will be calculated using the AERMAP preprocessor (Version 09040) with 7.5-minute United States Geological Survey digital elevation model (DEM) quadrangles (Elma, Montesano, Prices Peak, and South Elma) obtained from the internet (http://www.mapmart.com). These data have a horizontal spatial resolution of about 10 m. Terrain heights surrounding the facility indicate that some receptors are likely to be located in "complex terrain" (i.e., above plume height).

3.2.3 Meteorological Data

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

Surface Data Processing

A meteorological station located in Satsop, Washington was operated by MFG, Inc. for Duke Energy North America from May 2002 until May 2003. The Satsop meteorological station collected hourly wind speed, wind direction, solar radiation, differential temperature (delta-T), lateral wind turbulence (sigma-theta), vertical wind turbulence (sigma-w), temperature, relative humidity, station pressure, and precipitation (the annual data report is provided in Appendix A). The sensors employed and the audit procedures used meet USEPA requirements for meteorological data to support PSD permits. The Satsop station collected the necessary data for the regulatory dispersion model AERMOD. Table 3-1 presents the Satsop data recovery for all meteorological variables.

Table 3-1. Satsop Meteorological Site Data Recovery (May 20, 2002 – May 19, 2003)

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

The Satsop meteorological data includes the following variables at 10 m, 30 m, and 60 m above ground level: wind speed, wind direction, sigma-theta, sigma-w, temperature, and relative humidity. The Satsop meteorological data also included 2 m temperature, station pressure, solar radiation, temperature difference (10 m minus 2 m), temperature difference (30 m minus 10 m), temperature difference (60 m minus 10 m), and precipitation.

To prevent AERMET and AERMOD from developing unrealistic vertical turbulence profiles, Sigma-w values from the Satsop meteorological site were invalidated for any hour and level with a horizontal wind speed less than one meter per second. Figures 3-2 through 3-4 show sigma-w/horizontal wind speed versus horizontal wind speed at each meteorological sensor level (10 m, 30 m, and 60 m). As the figures show, sigma-w values at horizontal wind speeds less than one meter per second are uncharacteristic. Vertical wind velocities are less than the vertical anemometer threshold when horizontal wind speeds are less than about one meter.

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

Windrose plots presenting wind speed and wind direction data for the one year period at all three vertical observation levels are shown in Figures 3-5 through 3-7. The windroses show that the winds are predominantly from the west to south-southwest directions at all three vertical levels and from the east-northeast direction with increasing frequency at the 30 m and the 60 m heights. The wind flow patterns generally follow the Chehalis River valley. The average 10 m wind speed is 2.1 meters per second (m/s) and calm conditions occur less than three percent of the time. Overall, the average wind speed increases and the calm conditions decrease from 10 m to 60 m.

Upper Air Data Processing

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

Land Use Data Processing

Surface parameters including the surface roughness length, albedo, and Bowen ratio were determined for the area surrounding the Satsop meteorological tower using the AERMET preprocessor, AERSURFACE (Version 08009), and the USGS 1992 National Land Cover (NLCD92) land-use data set (http://landcover.usgs.gov/natlandcover.php). The NLCD92 data set used in the analysis has a 30 m mesh size and 21 land-use categories. Seasonal surface parameters were determined using AERSURFACE according to USEPA guidance.[3]

3 The AERMOD Implementation Guide (USEPA, 2008) and the AERSURFACE User's Guide (EPA-454/B-08-001,

Seasonal albedo and Bowen ratio values were based on averaging over a 10 km-by-10 km region centered on the Satsop meteorological tower site. An unweighted arithmetic average was used for calculating seasonal albedo; and an unweighted geometric average was used for calculating seasonal Bowen ratio. Seasonal surface roughness values were calculated for twelve 30 degree sectors within one kilometer of the Satsop meteorological tower location. An inverse-distance weighted geometric average was used to calculate seasonal surface roughness length values for each of the twelve sectors.

NLCD92 data combines transportation land-use (roadways and airport runways) into the same category as commercial and industrial land-use (industrial parks). Surface roughness values for roadways are much lower than values for an industrial parks or commercial areas with multiple buildings and structures. The AERSURFACE input file requires the user to state whether the meteorological site is located at an airport or not: the Satsop meteorological tower is not located at an airport.

AERSURFACE also requires the user to provide additional climatological information about the meteorological site and surrounding area. ENVIRON used historic Elma, Washington climate information to provide AERSURFACE with the required climatological information. The AERSURFACE user must answer the following questions:

- *Is the site located in an arid region?* NLCD92 data includes two land-use categories (shrubland and bare rock/sand/clay) to describe both desert and non-arid regions in the United States. Surface parameters for an arid region would include higher albedo and Bowen ratio values but lower surface roughness values compared to bare rock/sand/clay land-use. The Satsop meteorological tower site is not located in an arid region.
- *Is the site surface moisture dry, average, or wet?* AERSURFACE includes three sets of Bowen ratio values (dry, average, and wet) depending on the surface moisture of the site for the years modeled relative to a long term average. Annual average precipitation for the Elma/Satsop area during 2002 – 2003 is considered average compared to the last 30 years of precipitation records for the area.
- *Does the site experience continuous snow cover for most of the winter months (December, January, and February)?* AERSURFACE contains two sets of seasonal surface parameters values depending on the snow cover at the site. Surface parameters for continuous snow cover include lower Bowen ratio and surface roughness length values but higher albedo values compared to the surface parameters for winter months with no continuous snow cover. Annual average total snowfall for the Elma/Satsop area is approximately 6.4 inches, with an average snow depth during January, December, and February of approximately zero inches, indicating no continuous snow cover.

January 2008).

The land-use processing domain and NLCD92 land-use categories are shown in Figure 3-8. Table 3-2 presents the AERSURFACE calculated seasonal albedo, Bowen ratio, and surface roughness length values for the Satsop meteorological site.

Table 3-2. Satsop Meteorological Site AERSURFACE Parameter Summary

Sector	Winter			Spring		
	Albedo	Bowen Ratio	Surface Roughness Length (m)	Albedo	Bowen Ratio	Surface Roughness Length (m)
1	0.16	0.86	0.222	0.15	0.6	0.363
2	0.16	0.86	0.176	0.15	0.6	0.285
3	0.16	0.86	0.170	0.15	0.6	0.291
4	0.16	0.86	0.203	0.15	0.6	0.326
5	0.16	0.86	0.270	0.15	0.6	0.368
6	0.16	0.86	0.215	0.15	0.6	0.268
7	0.16	0.86	0.460	0.15	0.6	0.514
8	0.16	0.86	0.420	0.15	0.6	0.586
9	0.16	0.86	0.351	0.15	0.6	0.582
10	0.16	0.86	0.215	0.15	0.6	0.336
11	0.16	0.86	0.160	0.15	0.6	0.222
12	0.16	0.86	0.202	0.15	0.6	0.296
Sector	Summer			Autumn		
	Albedo	Bowen Ratio	Surface Roughness Length (m)	Albedo	Bowen Ratio	Surface Roughness Length (m)
1	0.16	0.42	0.472	0.16	0.86	0.472
2	0.16	0.42	0.356	0.16	0.86	0.356
3	0.16	0.42	0.370	0.16	0.86	0.370
4	0.16	0.42	0.402	0.16	0.86	0.402
5	0.16	0.42	0.423	0.16	0.86	0.423
6	0.16	0.42	0.297	0.16	0.86	0.297
7	0.16	0.42	0.542	0.16	0.86	0.542
8	0.16	0.42	0.685	0.16	0.86	0.685
9	0.16	0.42	0.741	0.16	0.86	0.741
10	0.16	0.42	0.487	0.16	0.86	0.487
11	0.16	0.42	0.384	0.16	0.86	0.384
12	0.16	0.42	0.409	0.16	0.86	0.409

AERMET Processing

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

3.2.4 Emission Source Release Parameters

Figure 3-9 shows the locations of emission sources that will be 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 that will be used to represent the point sources in the simulations is presented in Table 3-3.

Table 3-3. Point Source Release Parameters

Source[1]	Number of Sources	Stack Base Elev. (m)	Stack Height (m)	Exhaust Temp. (K)	Exit Velocity (m/s)	Stack Diam. (m)
CT @ 100% Load w/Duct Burner[1]	2	93	54.9	348 – 345	20.5 – 17.7	5.49
CT @ 100% Load[1]	2	93	54.9	356 – 353	20.8 – 18.0	5.49
CT @ 60% Load[1]	2	93	54.9	349 – 344	14.1 – 13.2	5.49
Auxiliary Boiler	1	94	14.9	477	20.8	0.54
Emergency Diesel Generator	1	94	4.0	761	94.6	0.15
Emergency Diesel Fire Water Pump	1	93	4.0	829	72.7	0.13
Cooling Tower	10	92	15.8	312	5.4	12.98

[1] Exhaust temperatures and exit velocities vary with the assumed power generation unit ambient temperature; the values show are the maximum and minimum used.

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 GHE will be used to prepare data for BPIP-PRIME, which provides the necessary input data for AERMOD. Figure 3-9 shows the configuration of significant structures that were used to develop the BPIP-PRIME input files, and Table 3-4 presents the heights of the significant structures that will be included in the simulations.

Table 3-4. Heights and Elevations of Significant On-Site Structures

Structure	Base Elevation (m)	Height Above Grade (m)
Ammonia Tank	93	7.9
Combustion Turbine #1	93	7.9
Combustion Turbine #2	93	7.9
Combustion Turbine #3	93	7.9
Combustion Turbine #4	93	7.9
Cooling Tower #1	93	15.9
Cooling Tower #2	93	15.9
De-mineralized Water Tank	93	11.9
Gas Conditioning Building	93	5.5
HRSG #1	93	24.4
HRSG #2	93	24.4
HRSG #3	93	24.4
HRSG #4	93	24.4
Inlet Air Filter #1	93	22.3
Inlet Air Filter #2	93	22.3
Inlet Air Filter #3	93	22.3
Inlet Air Filter #4	93	22.3
Raw Water Tank	93	15.2
Steam Turbine #1	93	14.0
Steam Turbine #2	93	14.0
Warehouse/Maintenance Building	93	7.6

3.3 Regulatory Thresholds and Standards

Criteria pollutants expected to increase as a result of the modification, as well as any TAPs exceeding the small quantity emission rates (SQERs) established in WAC 173-460, will be included in modification-only analyses to obtain the maximum predicted concentration increases for each pollutant using averaging periods appropriate for the ambient standard or TAP class. For criteria pollutants, the maximum concentration increase will be compared to the applicable significant impact levels (SILs – WAC 173-400-113(3)).

Facility-wide modeling will be developed for each PSD criteria pollutant predicted to exceed the SIL, and the design concentration calculated by the model, using the appropriate averaging period, will be added to the appropriate background concentration to assess compliance with the Washington or national ambient air quality standards (WAAQS or NAAQS). Criteria pollutants exceeding a non-PSD SIL (e.g., one-hour average SO_2) will be combined with a background concentration to evaluate compliance with the ambient standard. The maximum net TAP concentrations will be compared to the applicable acceptable source impact levels (ASILs) in WAC 173-460 to determine whether or not additional analyses are required to demonstrate compliance.

4 Air Quality Related Value Analysis Methodology

PSD regulations require an assessment of a project or modification's impacts on Air Quality Related Values (AQRVs) in Class I areas. AQRVs include regional visibility or haze; the effects of primary and secondary pollutants on sensitive plants; the effects of pollutant deposition on soils and receiving water bodies; and other effects associated with secondary aerosol formation. Through the PSD program, the Clean Air Act provides special protection for Class I areas. The FLMs for the Class I areas, the National Park Service (NPS), U.S. Fish and Wildlife Service, and U.S. Forest Service (USFS) have the responsibility of ensuring AQRVs in the Class I areas are not adversely affected.

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

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

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

3. Case 1 above plus maximum permitted 24-hour emissions from Unit1, Unit 2, Auxiliary Boiler 1, Diesel Generator 1, Fire Pump 1, and Cooling Tower 1.

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

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

4.1 Study Domain

PSD guidance requires an analysis of potential impacts to AQRVs in Federal Class I areas within 100 km (62.1 miles) of the project or modification. However, the FLMs generally request analyses of AQRV impacts for additional Class I areas within 200 km (124 miles) of the site. In the Pacific Northwest, the FLMs also request PSD sources disclose potential impacts to the Columbia River Gorge National Scenic Area (CRGNSA). This area is not subject to special protection under the Clean Air Act and model estimates are provided for information purposes only.

The proposed 428 km-by-444 km study domain is shown in Figure 4-1. The proposed domain is a subset of the domain used by the University of Washington (UW) for numerical weather predictions and includes all Class I areas within 200 km of the Grays Harbor Energy Center. Class I areas that will be considered in the analysis are shown in Figure 4-2. We also plan to include the CRGNSA and, at the request of the USFS, the Mt. Hood Wilderness. The closest Class I area is the Olympic National Park, approximately 58 km (36 miles) north of the site. The distances to all areas of interest are listed in Table 4-1.

Table 4-1. Class I Area And CRGNSA Distances From Facility

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

4.2 Model Selection

USEPA has adopted the CALPUFF modeling system as the preferred model for long-range transport assessments and for evaluating potential impacts to Class I areas. CALPUFF is included in Appendix A of the USEPA's Guideline on Air Quality Models (codified as Appendix W to 40 CFR Part 51). Features of the CALPUFF modeling system include the ability to consider: secondary aerosol formation; gaseous and particle deposition; wet and dry deposition processes; and complex three-dimensional wind regimes.

ENVIRON plans to use Version 5.8 of the CALPUFF modeling system; the release date of the versions to be used is June 23, 2007. The CALPUFF modeling system is comprised of three main components: the CALPUFF dispersion model, the CALMET meteorological pre-processor, and the CALPOST post-processor. A number of other utilities provided with the system will also be applied to aid in the preparation of the meteorological/geophysical data and to manipulate the large CALPUFF output files.

Examples of the input files for the three components of the CALPUFF modeling system are included in Appendix B, Appendix C, and Appendix D, for CALMET, CALPUFF, and CALPOST, respectively. The remainder of the protocol discusses some of the more important aspects of the data sets and options that can be viewed in more detail by examination of these appendices.

4.3 Modeling Procedures

The modeling procedures to be used for the Class I area analyses will follow the recommendations of the Interagency Agency Workgroup on Air Quality Modeling (IWAQM) and the FLM Air Quality Related Values Workgroup (FLAG), outlined in the FLAG Phase I Report (December 2000). USEPA endorsed these procedures in advance in the IWAQM Phase II report (December 1998), and reiterated this endorsement in the April 15, 2003 Federal Register notice (Volume 68, Number 72) that adopted CALPUFF as a Guideline model. Regulatory switches recently added as part of the latest Version 5.8 update would also be used. Appendix C shows an example CALPUFF input file for the 2003 simulations.

4.4 PM_{10} Fractions And Species

Data characterizing the chemical composition of the PM_{10} emitted are needed for the AQRV analysis using the CALPUFF modeling system. PM_{10} emission rates must be divided into six species, including: soot or elemental carbon (EC), fine soil particles (PMF), coarse particles (PMC), organic carbon[4] (OC), sulfate (SO_4), and nitrate (NO_3).

Table 4-2 shows the PM_{10} fractions and species emission rates assumed for each Unit 3 and Unit 4 related source in the CALPUFF short-term simulations. Similar techniques will be used divide PM_{10} emissions for the annual and Unit 1 and Unit 2 sources when included in the simulations. Cooling tower emissions are assumed to be entirely PMF. Following NPS guidance for gas-fired turbines[5], all of the PM_{10} emissions are assumed to be $PM_{2.5}$ (no PMC emissions). The filterable fraction is assumed to be 25 percent of the PM_{10} emissions and to consist of EC. The remaining condensable fraction is assumed to be ammonium sulfate, based on a 33 percent conversion of the SO_2, and OC. To avoid double counting the sulfur emissions from the gas-turbines, SO_2 emissions in the simulations will be reduced by the amount assumed to form ammonium sulfate. Ammonium nitrate and PMF emissions are assumed to be negligible.

For the diesel-fired generator, fire pump and auxiliary boiler, we plan to use $PM_{2.5}/PM_{10}$ ratios and $PM_{2.5}$ fractions from a database provided by Washington State Department of Ecology (Ecology) for use in Best Available Retrofit Technology (BART) modeling analyses. The $PM_{2.5}$ fractions in the database are based on profiles recommended by the USEPA for the Community Multi-Scale Air Quality (CMAQ) model.[6] CMAQ is the preferred regulatory model for $PM_{2.5}$ and regional haze simulations. The CMAQ profile database is indexed by Source Classification Code (SCC). Should updated or more appropriate $PM_{2.5}/PM_{10}$ ratios become available following submittal of this protocol, they will be used instead of those described here.

---

4 For the purposes of post-processing by CALPOST, the species OC is labeled SOA (secondary organic aerosol) in the CALPUFF input and output files. CALPOST actually looks for “SOA” when calculating extinction. We assume all OC emitted forms SOA.

5 The NPS guidance can be found at http://www.nature.nps.gov/air/permits/ect/ectGasFiredCT.cfm

6 EPA website containing PM speciation by source categories: http://www.epa.gov/ttn/chief/emch/speciation.

Table 4-2. PM_{10} Fractions and Species

Model ID	$PM_{2.5}$ to PM_{10} Ratio[1]	PM_{10} Species 24-hour Maximum Emission Rate (lb/hr)						
		Ammonium Sulfate	SO_4	NO_3	PMC	PMF	EC	SOA/OC
Unit 3	1	8.972	6.525	0.000	0.0	0.000	4.750	5.278
Unit 4	1	8.972	6.525	0.000	0.0	0.000	4.750	5.278
Aux Boil 2	1	0.029	0.021	0.0006	0.0	0.028	0.000	0.088
Dies. Gen 2	1	0.000	0.000	0.000	0.0	0.000	0.006	0.002
Fire Pump 2	1	0.000	0.000	0.000	0.0	0.000	0.006	0.002
Cooling Towers	1	0.000	0.000	0.000	0.0	0.788	0.000	0.000

[1] If updated or more appropriate $PM_{2.5}/PM_{10}$ ratios become available, they will be used instead of those presented here.

4.5 Meteorological Data

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

CALMET (Version 5.8), the meteorological preprocessor component of the CALPUFF system, will be 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.

In 2007, USEPA Region 10, the FLMs, and the state agencies of Washington, Oregon, and Idaho (hereafter the PNW states) issued a template of recommended options for CALMET regulatory analyses.[7] ENVIRON proposes to follow the PNW states recommended CALMET input file options with one exception. Based on recent conversations with the FLMs, ENVIRON will also include available upper air sounding data in the preparation of a meteorological database.

---

7 Wong, Herman, 2007. *CALMET V5.8 Template.* Email from Herman Wong, EPA Region 10 to Ken Richmond, Geomatrix, August 23, 2007.

Appendix B includes a listing of a sample CALMET input file for January 2003. Major features of the CALMET application and input data preparation are as follows:

- The proposed model domain is a subset of the UW's 4-km mesh size MM5 domain as shown in Figure 4-1. The horizontal mesh size will be 4 km, with each CALMET grid point matched to a MM5 grid point. There will be ten vertical levels, ranging geometrically from the surface to 4,000 m. In order to match the MM5 simulations, a Lambert Conformal Conic (LCC) coordinate system will be used with an origin of 49N, 121W and standard latitudes of 30N and 60N.
- MM5 winds based on a 4-km grid spacing for January 2003 to December 2005 will be used to initialize the three-dimensional wind field predictions. The MM5 data will be processed with the CALMM5 utility for use by CALMET.
- Land use and terrain data will be prepared using the processing tools accompanying the CALPUFF modeling system and the USGS GTOPO30 elevation data sets available on the Internet resulting in 4-km mesh size fields. Figure 4-3 shows the 4-km mesh size terrain to be used in the simulations.
- ENVIRON has constructed surface weather observations for the Pacific Northwest West using the National Center of Atmospheric Research dataset ds472.0. Figure 4-4 shows the surface weather observation stations in and around the proposed modeling domain. The individual stations vary slightly for each of the years (2003-2005). A full listing of the 155 surface stations for 2003 is included in Appendix B.
- Twice daily upper air soundings will be blended with the MM5 data for winds and used for upper air temperatures. The locations of the upper air stations are shown in Figure 4-5. CALMET requires a continuous set of soundings from each upper air site. Missing soundings at each site will be replaced by a MM5 pseudo-sounding from the closest grid point to the station location.
- Buoy observations from the National Data Buoy Center will be used to characterize winds, sea-air temperature differences, and air temperatures over marine areas of the domain. The location of the buoy data sets are shown in Figure 4-6. The buoy data will be processed by the BUOY utility from the CALPUFF modeling system.
- Hourly precipitation data will be obtained from the National Climatic Data Center's TD-3240 (COOP) dataset and processed with the CALMET utility PMERGE. Sites were selected based on the criteria that the locations must be near or in the model domain and there must be at least a 25 percent data recovery. Using this criteria, historic precipitation data from this dataset are available for between 64 and 68 stations depending upon the year. A full listing of the 66 stations available for 2003 are shown in Appendix B.
- In order to augment the precipitation observations especially in mountainous and marine areas, simulated hourly precipitation using every third grid point of the MM5 4-km domain will also be included in the meteorological data set. Figure 4-7 shows the locations of the combined precipitation data set.

- Interpolation options will be selected using the PNW states recommended CALMET options to blend the MM5 initial fields with the surface, precipitation and upper air observations (See Appendix B).

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

4.6 Receptor Network

The proposed receptor network is plotted in Figure 4-8. The CALPUFF dispersion model simulations will assess AQRVs within each Class I area at discrete receptors obtained from the NPS.[8] Receptors will also be located within the CRGNSA using the locations and elevations provided by USEPA Region 10 for Pacific Northwest BART simulations. In addition to the discrete receptors, a receptor grid with 4-km spacing will also be used throughout the CALPUFF modeling domain for AQRV predictions. The 4-km mesh size receptors will be used to construct plots showing the spatial variation of the calculated parameters throughout the modeling domain. These plots will be used for diagnostic purposes, as well as to develop figures that will be presented in the permit application. Comparisons with AQRV criteria will be based solely on the discrete receptor locations.

4.7 Ammonia and Ozone Background Concentrations

The NOx 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 usually not explicitly simulated by CALPUFF and the FLMs recommend an appropriate background concentration be used for ammonia.

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. In the current analysis, we propose to use 17 ppb for the background ammonia concentration. This conservative concentration was recommended for Pacific Northwest BART simulations and is based on measurements in southern British Columbia. This relatively high background ensures the conversion of NO_X to ammonium nitrate is not limited by a lack of ammonia for the range of NO_X concentrations predicted in this study.

Reaction rates in the CALPUFF chemistry algorithms are influenced by background ozone concentrations. In order to conservatively characterize ozone concentrations throughout the domain, ENVIRON proposes to use hourly a background ozone concentration of 60 ppb as recommended by the USFS.

---

8 The NPS receptor database can be obtained at http://www2.nature.nps.gov/air/Maps/Receptors/index.cfm

4.8 Post-Processing Procedures

The CALPUFF modeling system will be used to predict criteria pollutant concentrations, concentrations of PM_{10} species that contribute to regional haze, deposition (wet and dry) fluxes for nitrogen containing pollutant species, and deposition fluxes for sulfur species. For each emission case considered, three annual simulations will be performed in parallel for each of the three years (2003-2005). In order to account for plumes that may remained within the domain at the end of the year, the simulations for 2004 and 2005 will start two days early.

The CALPUFF utility POSTUTIL will be used to manipulate the large CALPUFF output files and calculate a number of the parameters needed to assess AQRVs in the areas of interest. Specifically, POSTUTIL will be used to:

- Adjust the nitric acid/ammonium nitrate equilibrium to account for possible overlapping plumes using the MNITRATE=1 option. Initially the post-processing will be performed without this option. The option may be employed if AQRV criteria related to nitrate formation are exceeded.
- Sum the sulfur and nitrogen portions of the deposited gaseous and particle compounds to estimate the total sulfur and nitrogen deposition fluxes. The nitrogen in the ammonium nitrate and ammonium sulfate, including the portion that might be from the background ammonia, will be incorporated in the total.
- Sum the individual PM_{10} species together after accounting for the differences in molecular weight between the species in the CALPUFF output files and the actual component species of PM_{10}.

Following the application of POSTUTIL, the CALPOST post-processor will be used to summarize the modeling results and obtain maximum predicted concentrations of NO_x, SO_2, and PM_{10} in Class I areas and in the CRGNSA. Table 4-3 summarizes the applicable Class I Significant Impact Levels (SILs) and Class I PSD increments. 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.

Table 4-3. Class I Area Significance Levels and Increments

Pollutant	Averaging Period	PSD Class I Increment	USEPA SIL [1]	FLM SIL [1]
PM_{10}	Annual	4	0.2	0.08
	24-hour	8	0.3	0.27
SO_2	Annual	2	0.1	0.03
	24-hour	5	0.2	0.07
	3-hour	25	1	0.48
NO_2	Annual	2.5	0.1	0.03

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

Figures will be provided to show the spatial variation across the simulation domain of the predicted maximum criteria pollutant concentrations attributable to the proposed modification. These figures will be constructed from the maximum predictions obtained at the 4-km mesh size grid receptors, and will be provided so the FLMs can assess the spatial extent of potential impacts from the Grays Harbor Energy Center.

Predicted annual sulfur and nitrogen deposition fluxes will be used as a measure to assess potential impacts to soils and vegetation in regional Class I areas and the CRGNSA. There are no promulgated standards for evaluation of these incremental impacts to soils and vegetation in Washington. However, the FLMs have established Deposition Analysis Thresholds (DATs) for nitrogen and sulfur of 0.005 kilograms per hectare per year (kg/ha/yr).[9] These "thresholds" are based on natural background deposition estimates 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 nitrogen and sulfur deposition flux results of the CALPUFF simulations for each Class I area and the CRGNSA will be compared to the DATs. ENVIRON will construct contour plots showing the spatial variation of the predicted nitrogen and sulfur deposition fluxes over the entire modeling domain.

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

- Extinction coefficients will be calculated using hourly predicted aerosol concentrations, hourly relative humidity, and background aerosol concentrations with CALPOST Method 2 (MVISBK = 2). Relative humidly will be capped at 95 percent (RHMAX=95) and the FLAG relative humidity growth factors will be applied to the hygroscopic aerosols (MFRH=2)
- Default light extinction scattering efficiencies will be used for each aerosol species
- Background visibility in all Class I areas of interest will be based on the FLAG defaults for the western US by using the hygroscopic (0.6 Mm-1), dry (4.5 Mm-1), and Rayleigh scattering (10.0 Mm-1) portions of the extinction coefficient. These defaults will be applied within CALPOST during post-processing with the following options: BKSO4=0.2, BKSOIL=4.5 and BEXTRAY=10.

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

A sample CALPOST input file that would be used to summarize the visibility results for 2003 and the Alpine Lakes Wilderness is included in Appendix D.

The current FLAG recommended CALPOST method for extinction coefficients can be very sensitive to hourly relative humidity. High relative humidity in the Pacific Northwest is often associated with precipitation, fog, low overcast and weather related visibility obscuring phenomena. In order to provide the FLMs with further information, extinction coefficients will also be calculated using the 2008 proposed revisions to the FLM FLAG procedures.[10] The revised procedures employ an updated equation for extinction (invoked with MVISCHECK=1) using monthly relatively humidity adjustment factors and background aerosol concentrations recommended by the FLMs for each Class I area. In order to use this method, CALPOST Version 6.221 (Level 080724) will be used to post-process the CALPUFF output files.

The visibility related AQRVs will be summarized for each area of interest in a series of tables showing the number of days the five percent change to extinction was exceeded and showing the extinction budgets for the top eight days in each year of the simulation and any day with a change to extinction greater than 5 percent. Time series plots will be used to display the seasonality of the modeling results and contour plots of the predicted maximum 24-hour extinction coefficients will be used to examine spatial variability.

10 EPA, 2008. Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report – *Revised*. June 27, 2008 Draft.

Figures

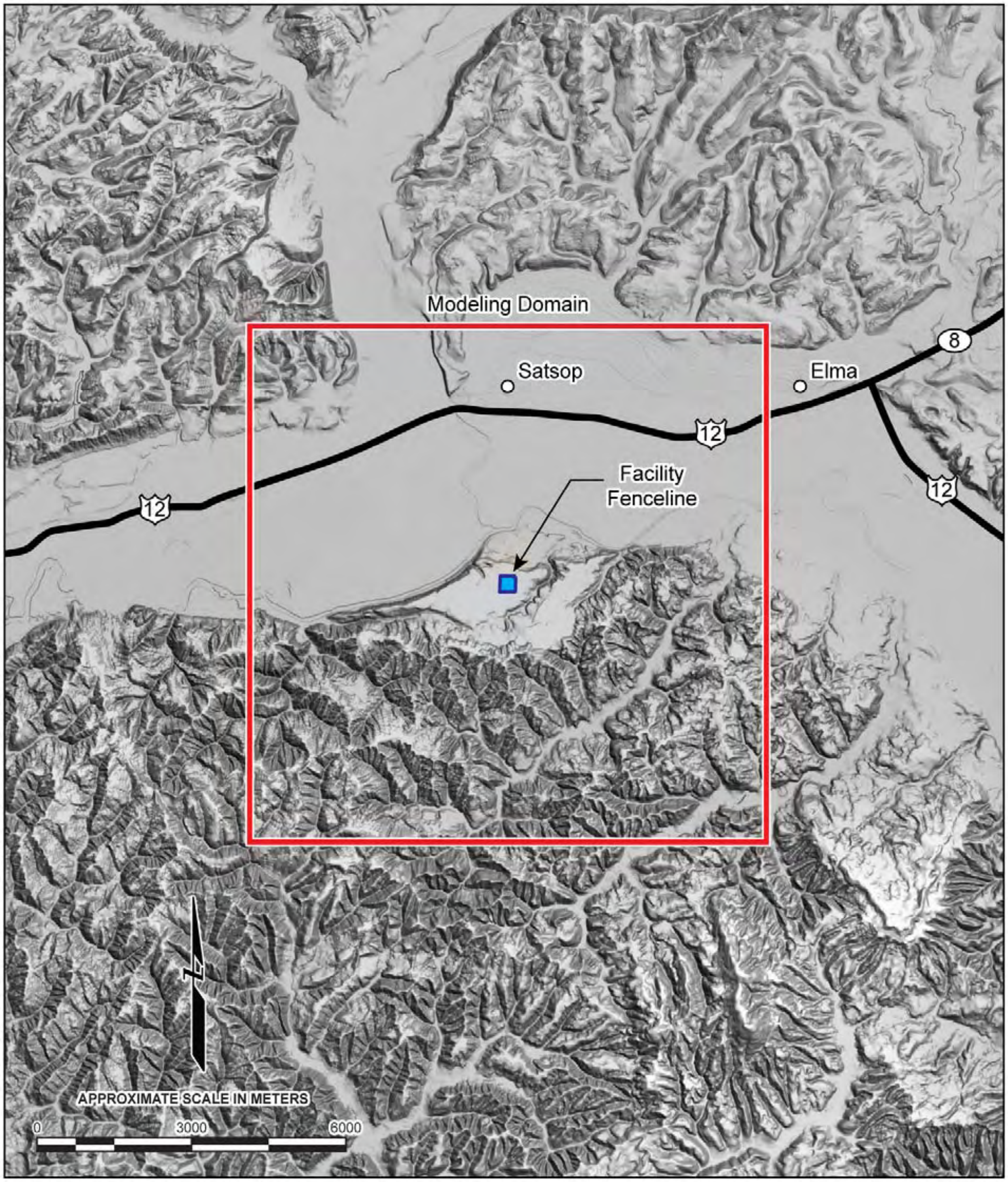


Figure 2-1. Modeling Domain for Near-Field Air Quality Impact Analysis

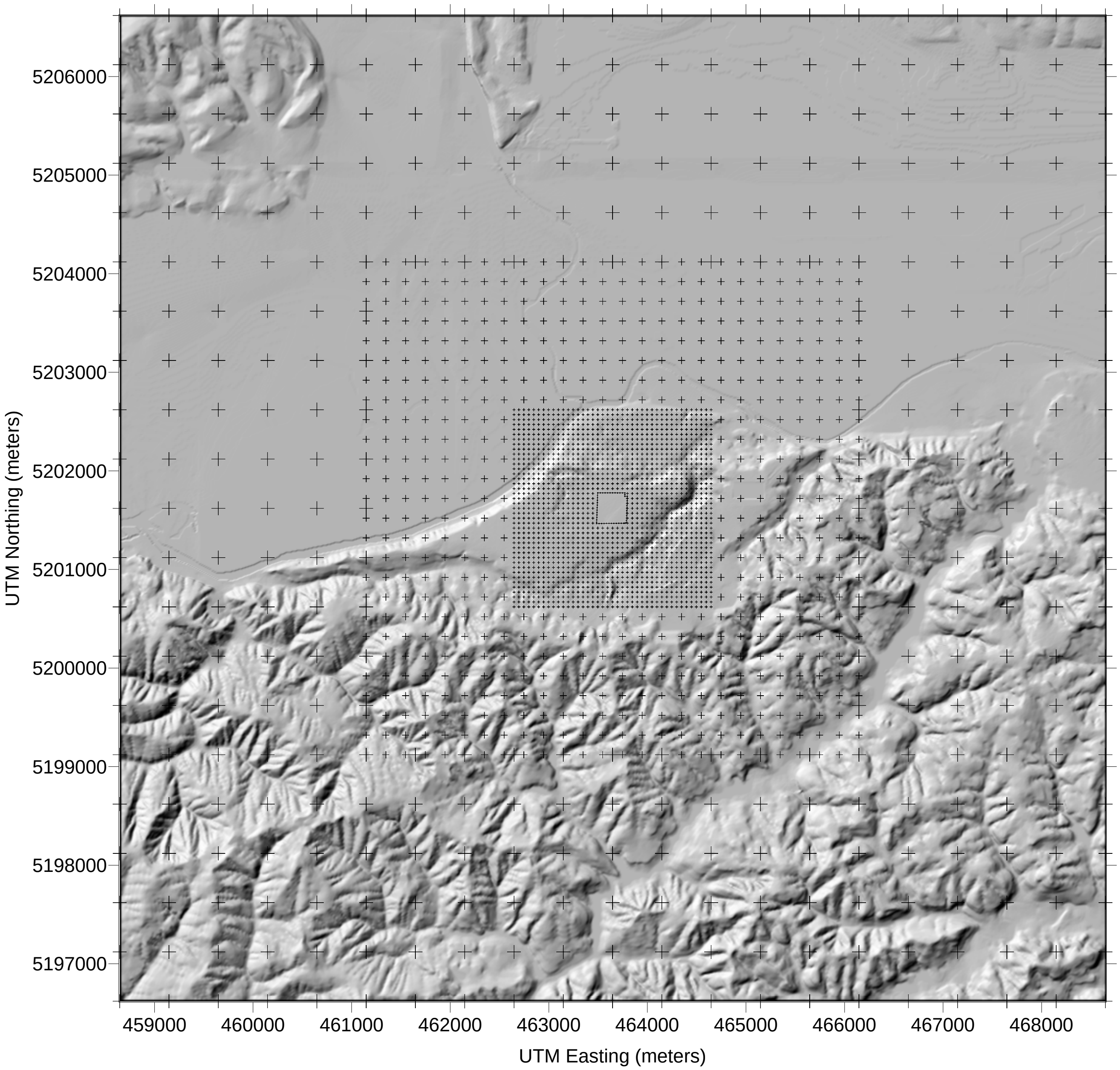


Figure 3-1. Preliminary Near-Field Modeling Receptor Locations

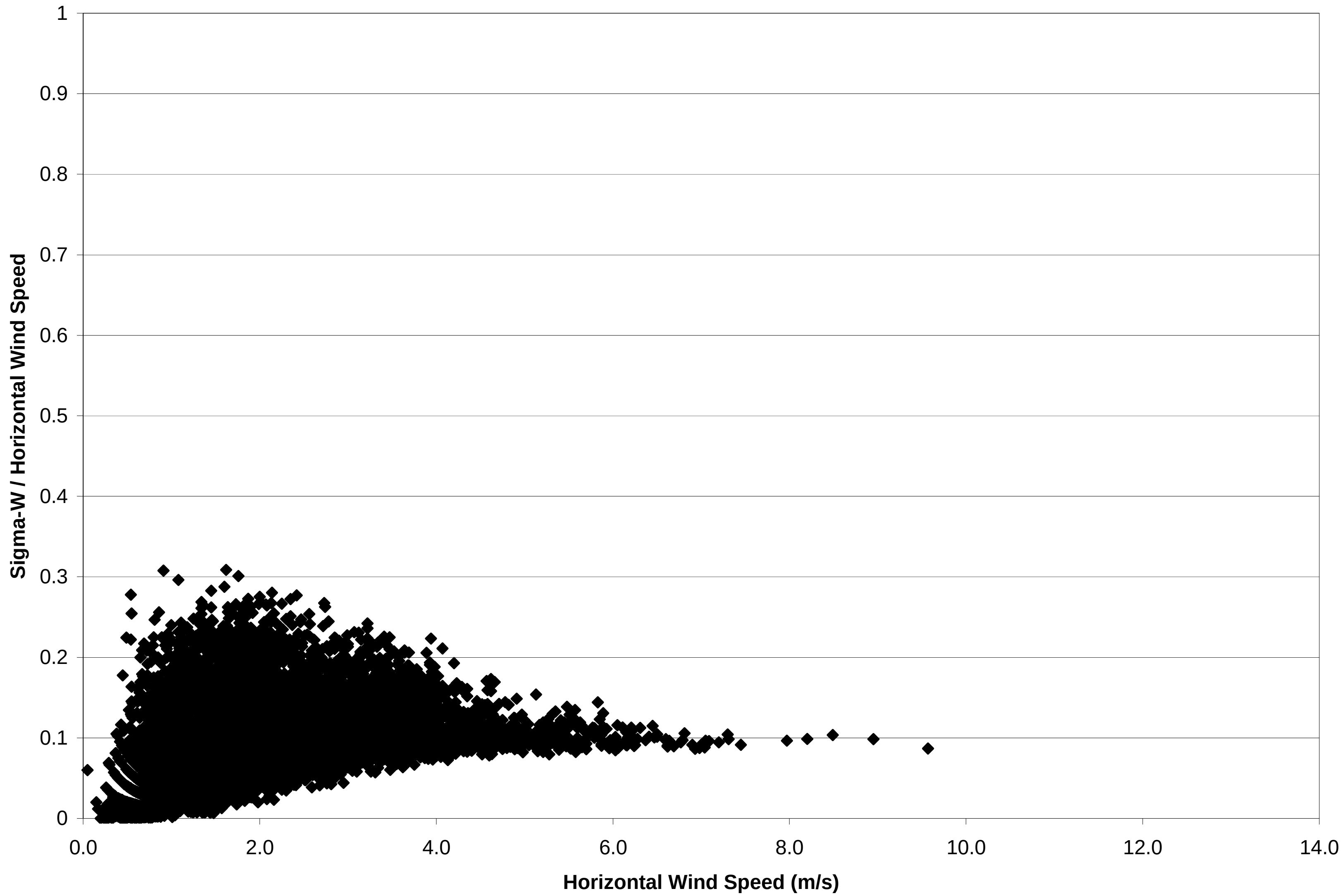


Figure 3-2. Normalized Sigma-W Versus Wind Speed Measured At 10 Meters

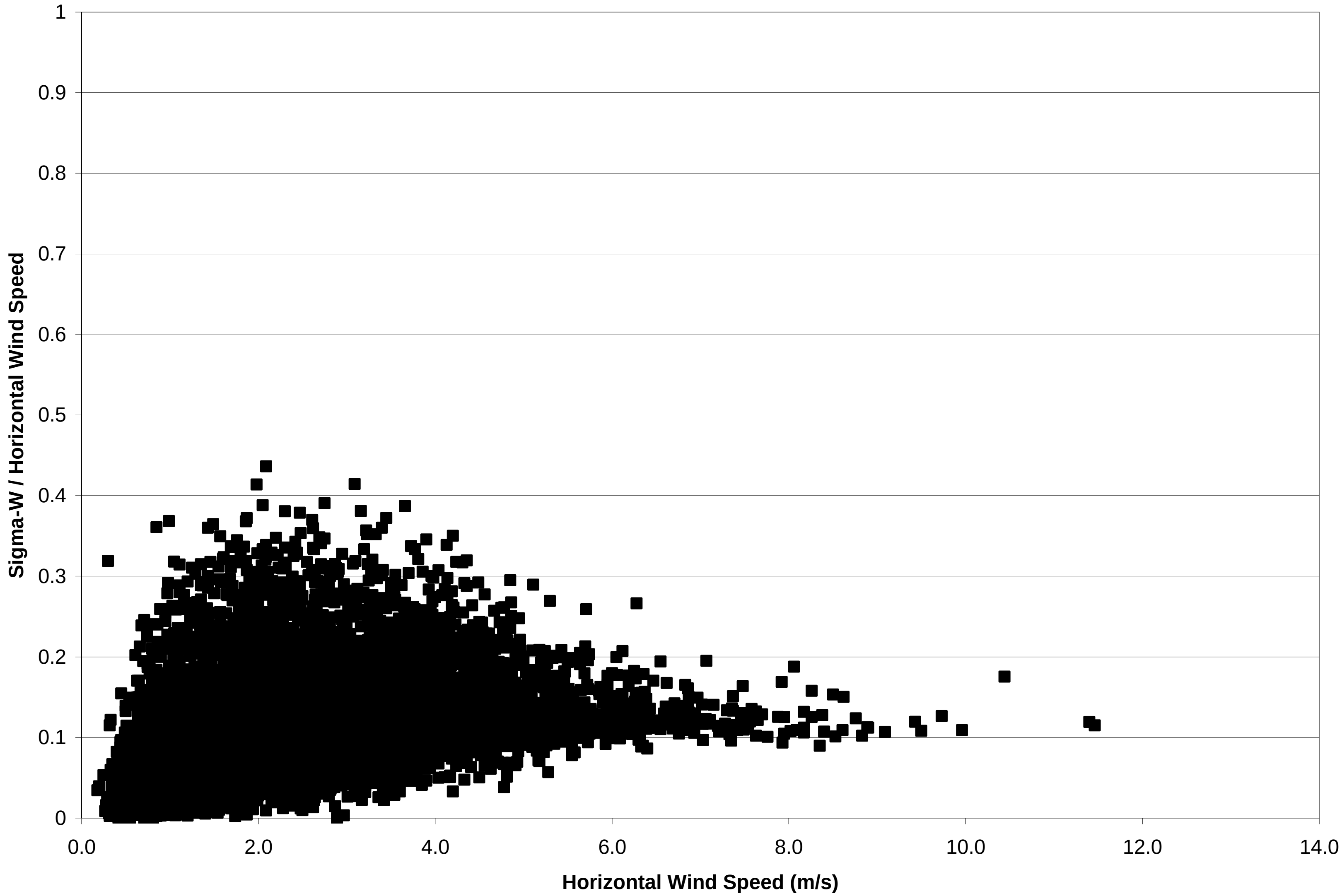


Figure 3-3. Normalized Sigma-W Versus Wind Speed Measured At 30 Meters

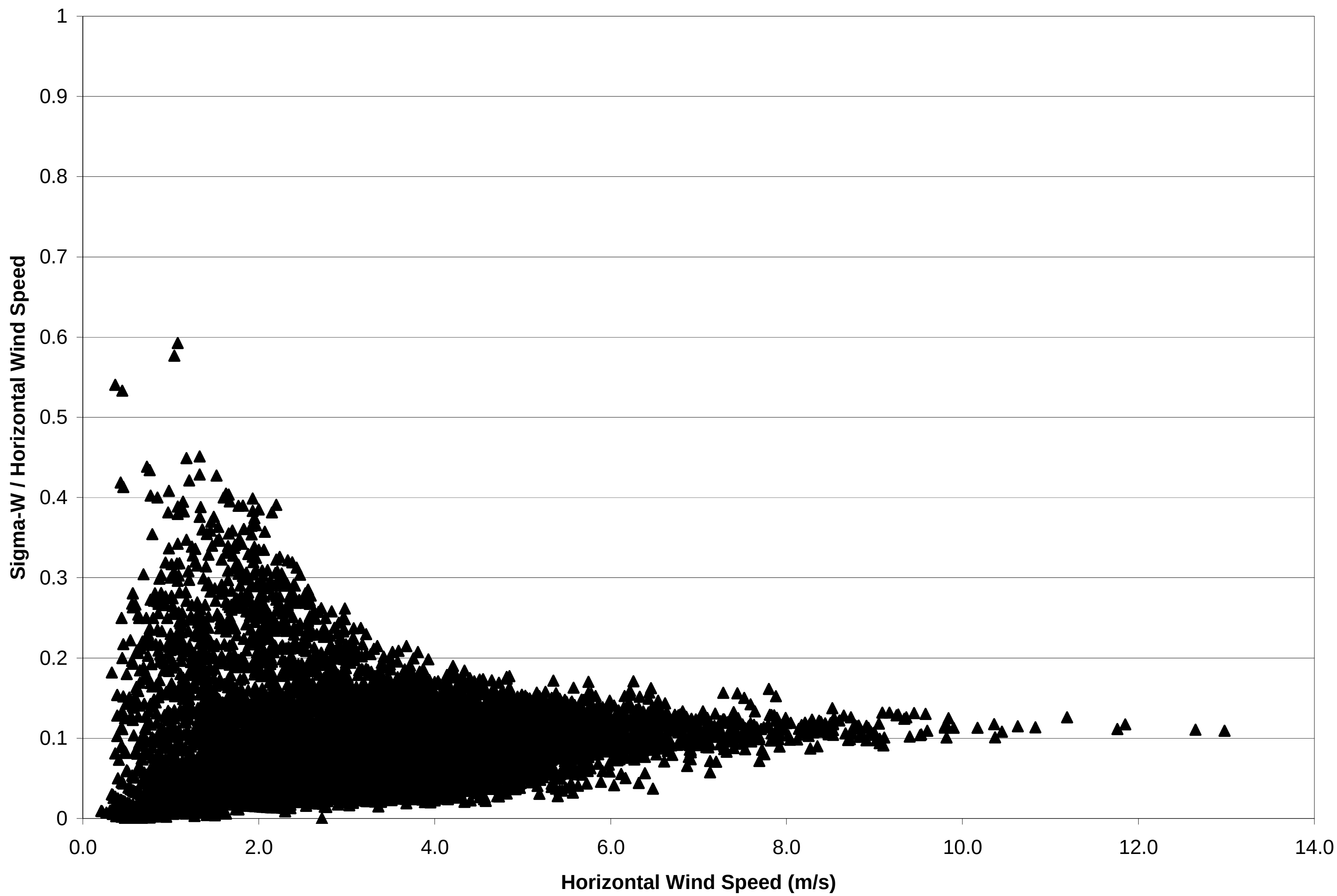


Figure 3-4. Normalized Sigma-W Versus Wind Speed Measured At 60 Meters

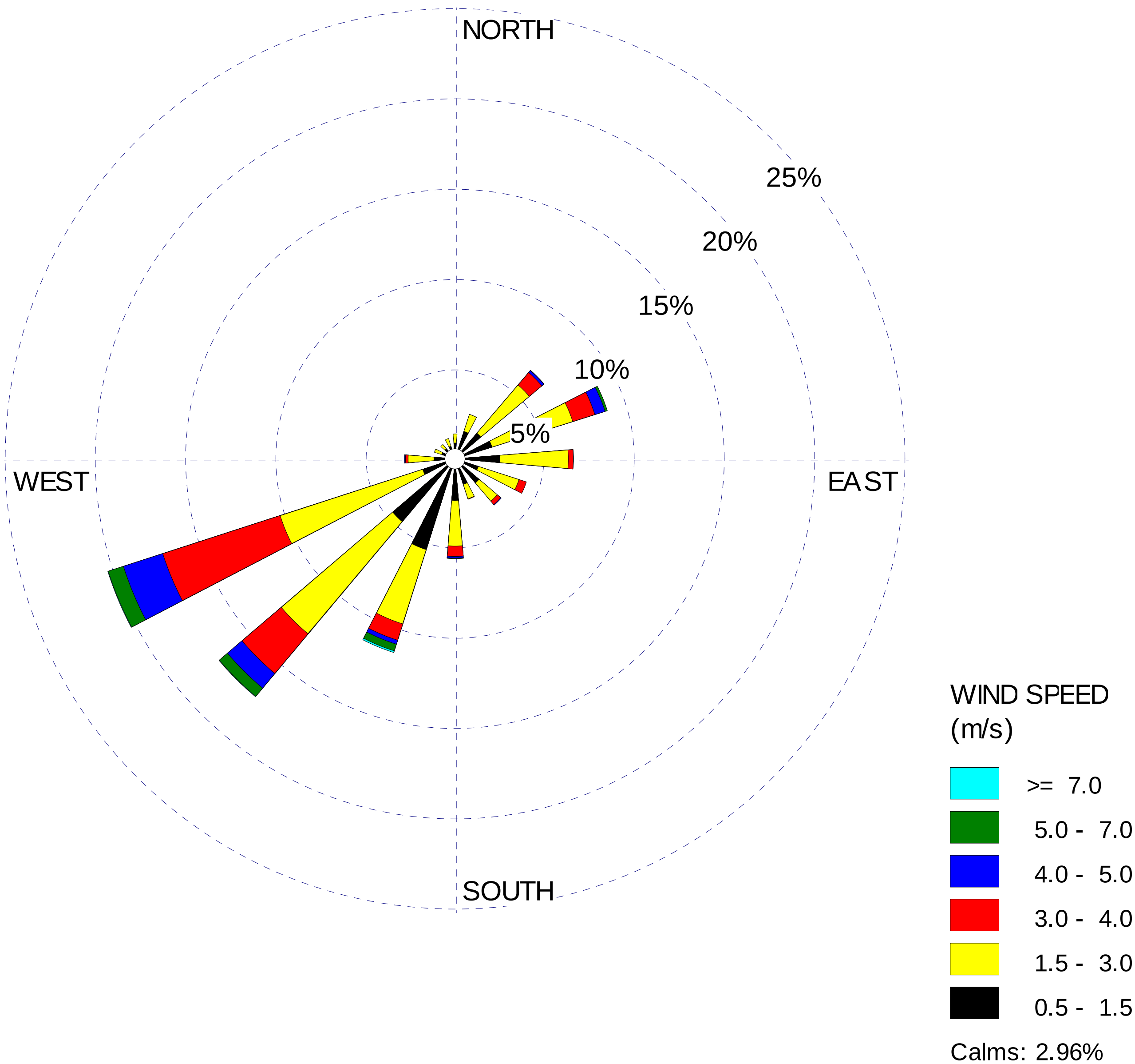


Figure 3-5. Windrose for Satsop, 2002 – 2003, 10 m Level

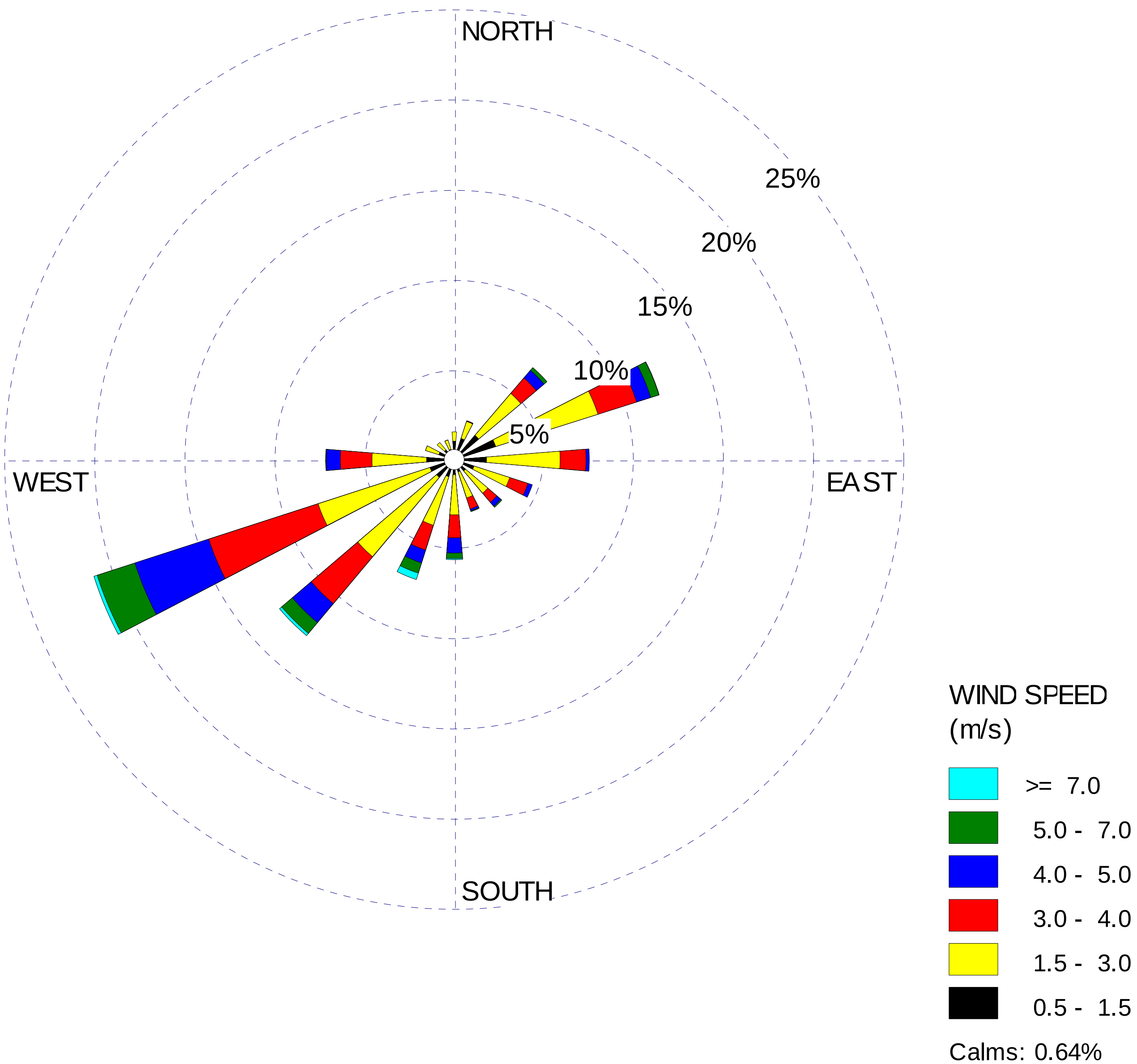


Figure 3-6. Windrose for Satsop, 2002 – 2003, 30 m Level

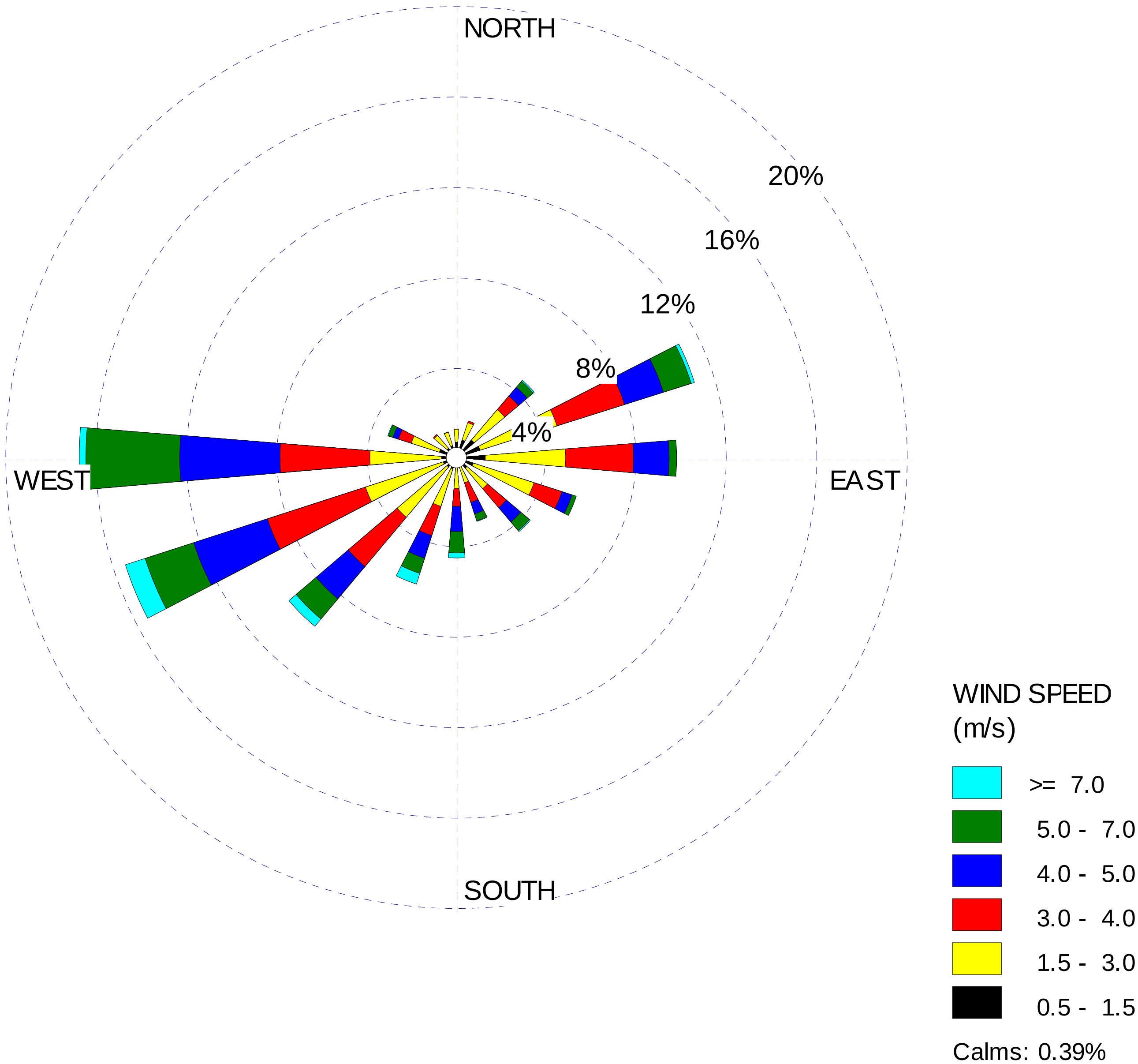


Figure 3-7. Windrose for Satsop, 2002 – 2003, 60 m Level

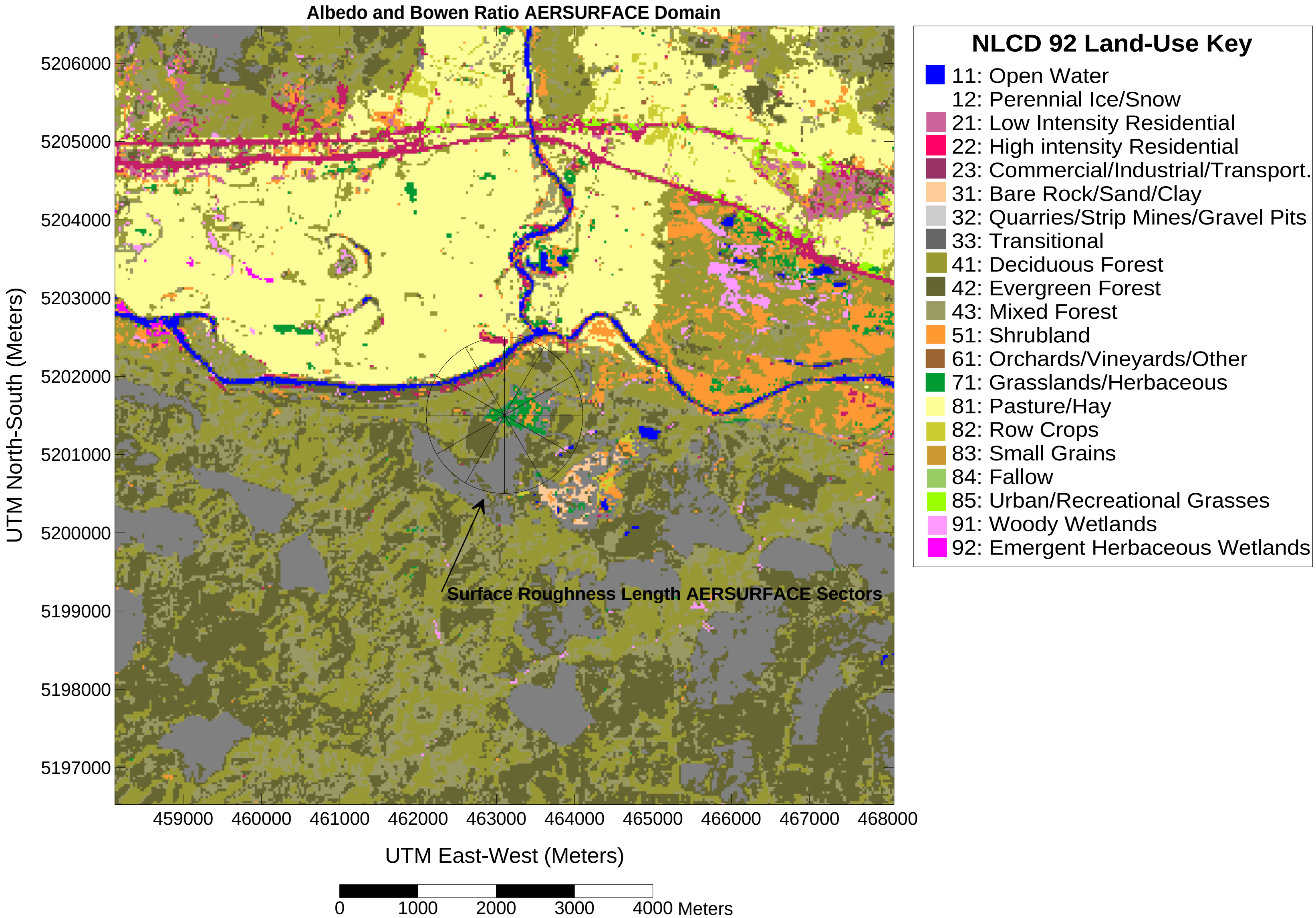


Figure 3-8. Satsop Meteorological Station AERMET Land-Use Analysis

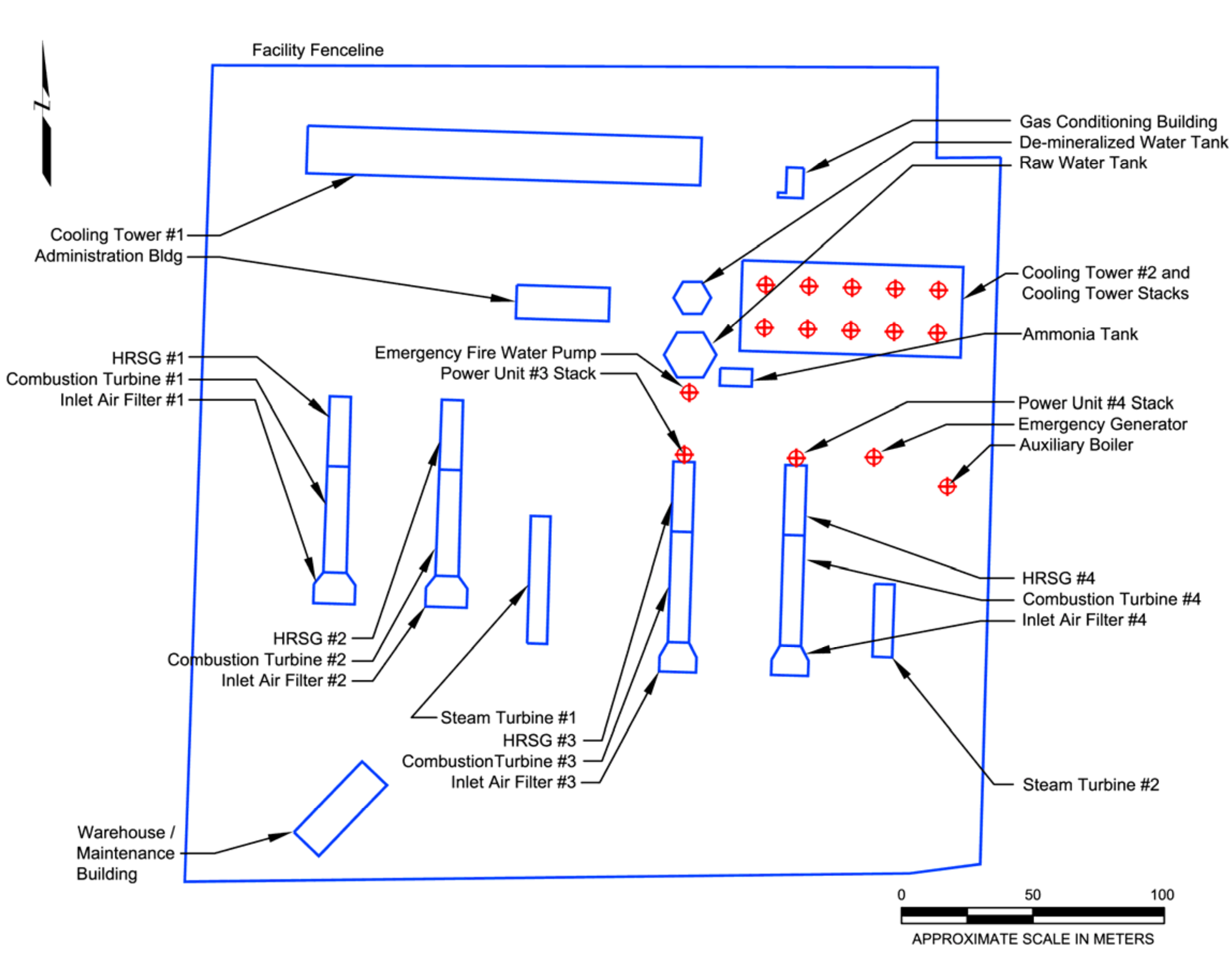


Figure 3-9. Significant On-Site Structures and Modeled Sources

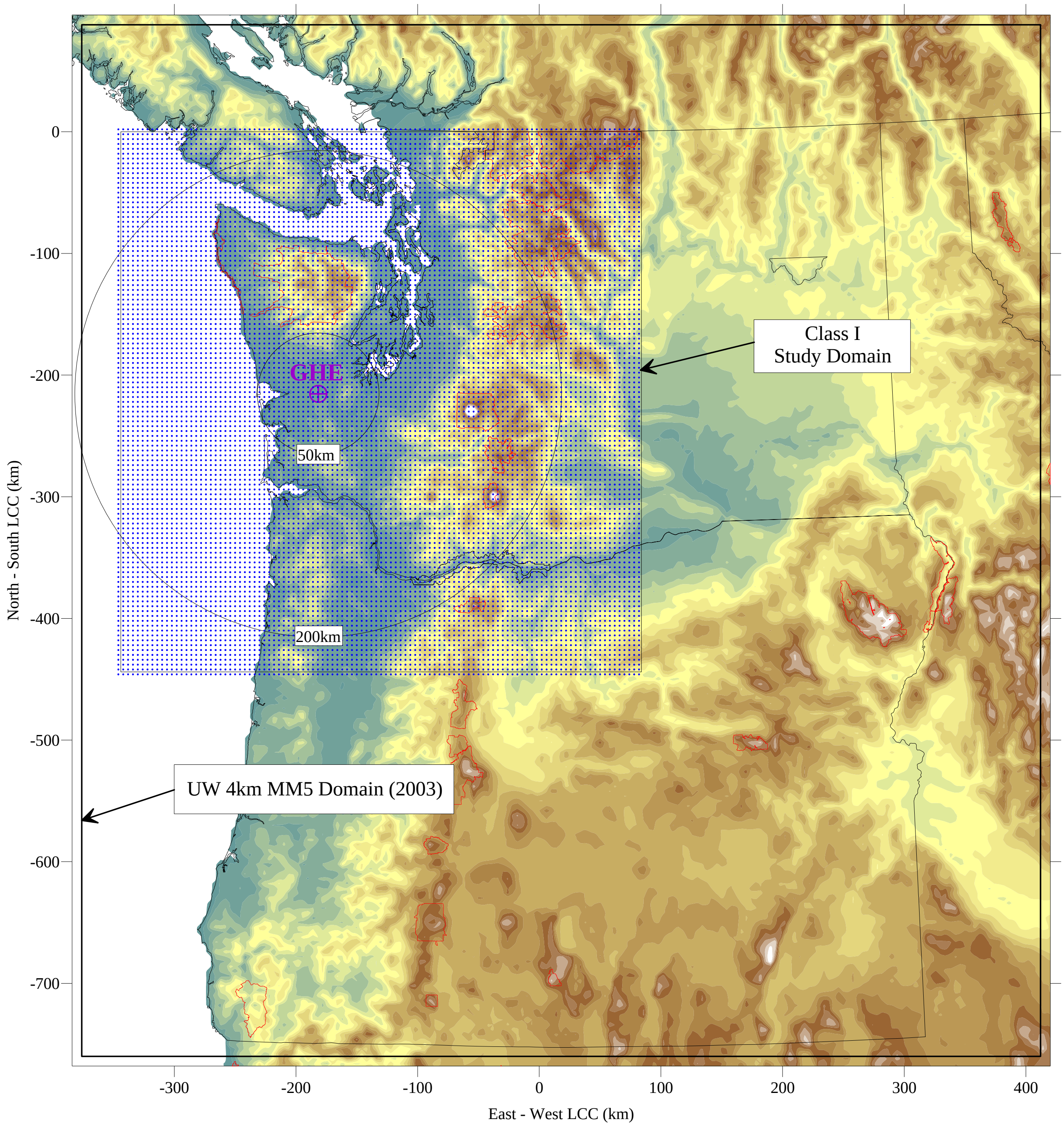


Figure 4-1. Modeling Domain for AQRV Analysis

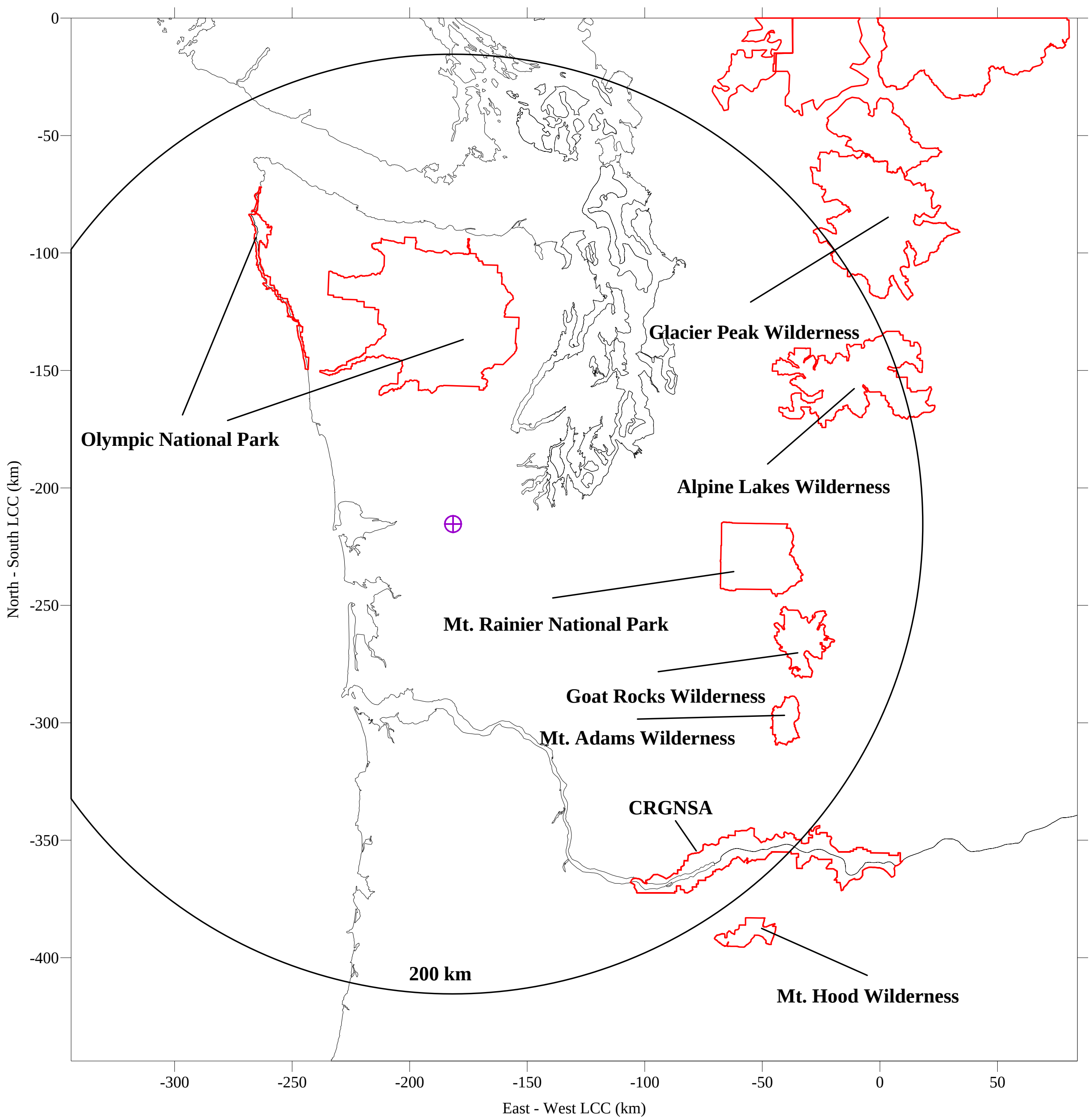


Figure 4-2. Locations of Class I Areas and CRGNSA within AQRV Modeling Domain

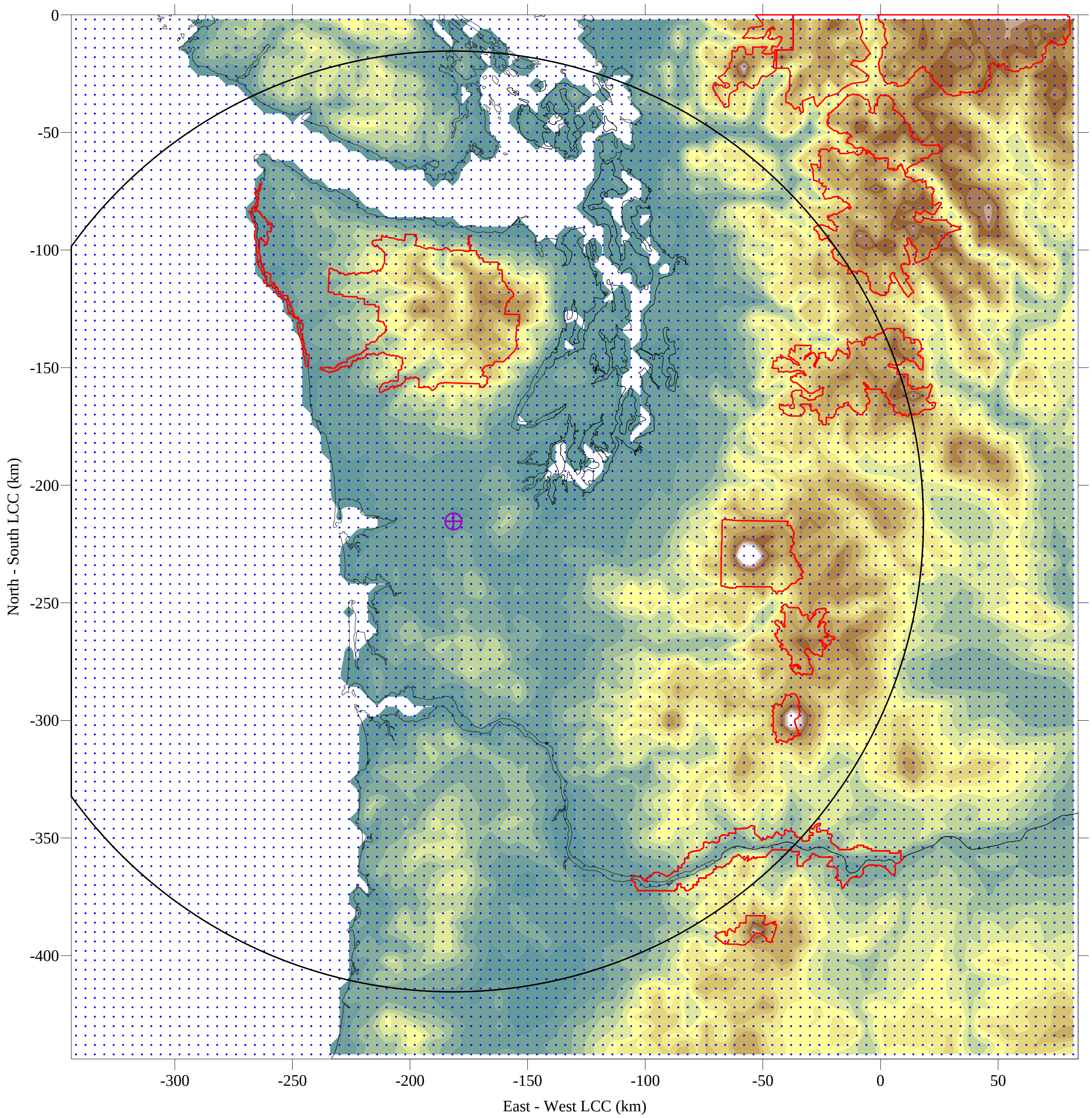


Figure 4-3. CALMET 4-Kilometer Mesh-Size Terrain and Grid Points

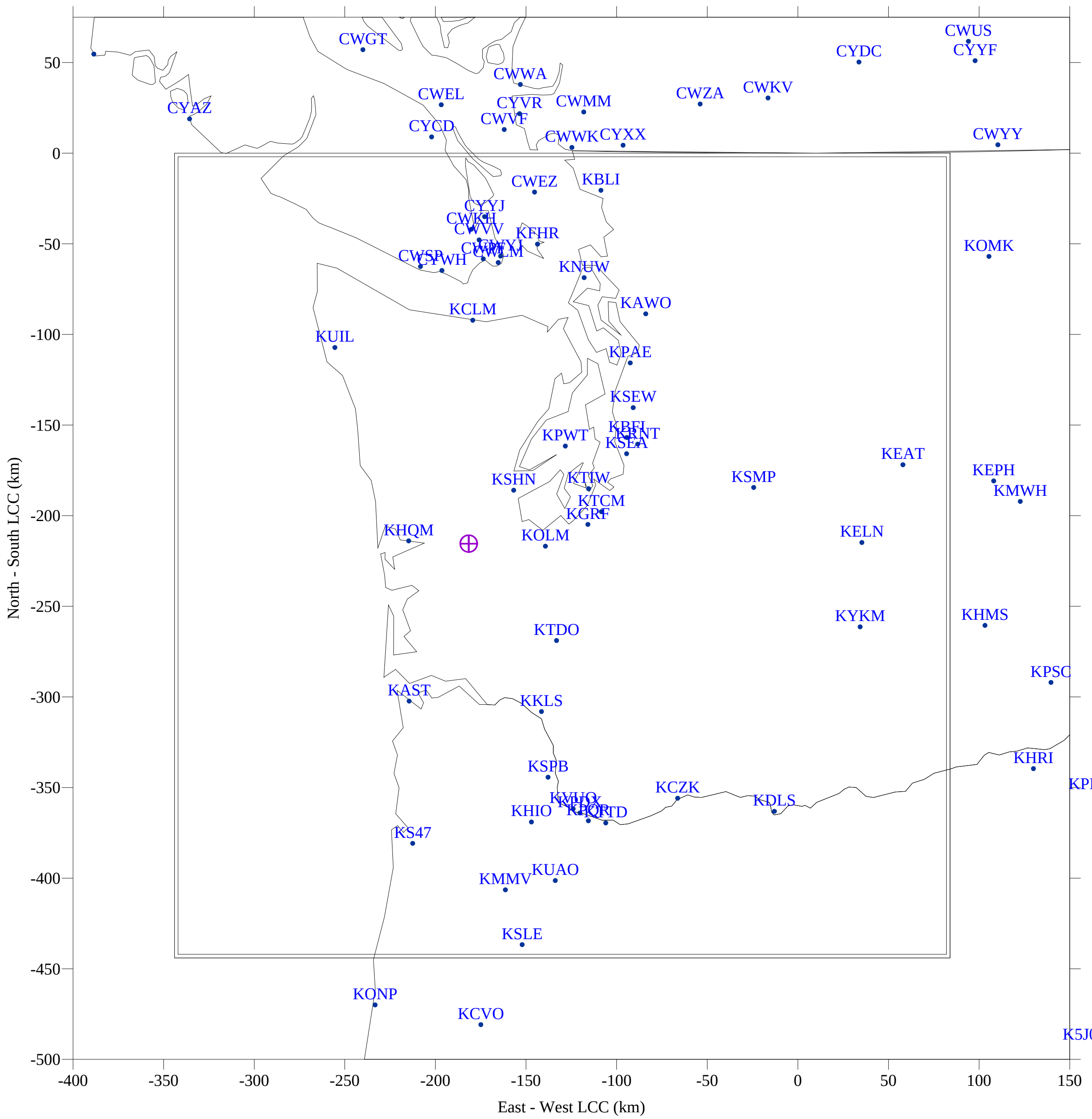


Figure 4-4. Surface Meteorological Stations In and Around the Modeling Domain

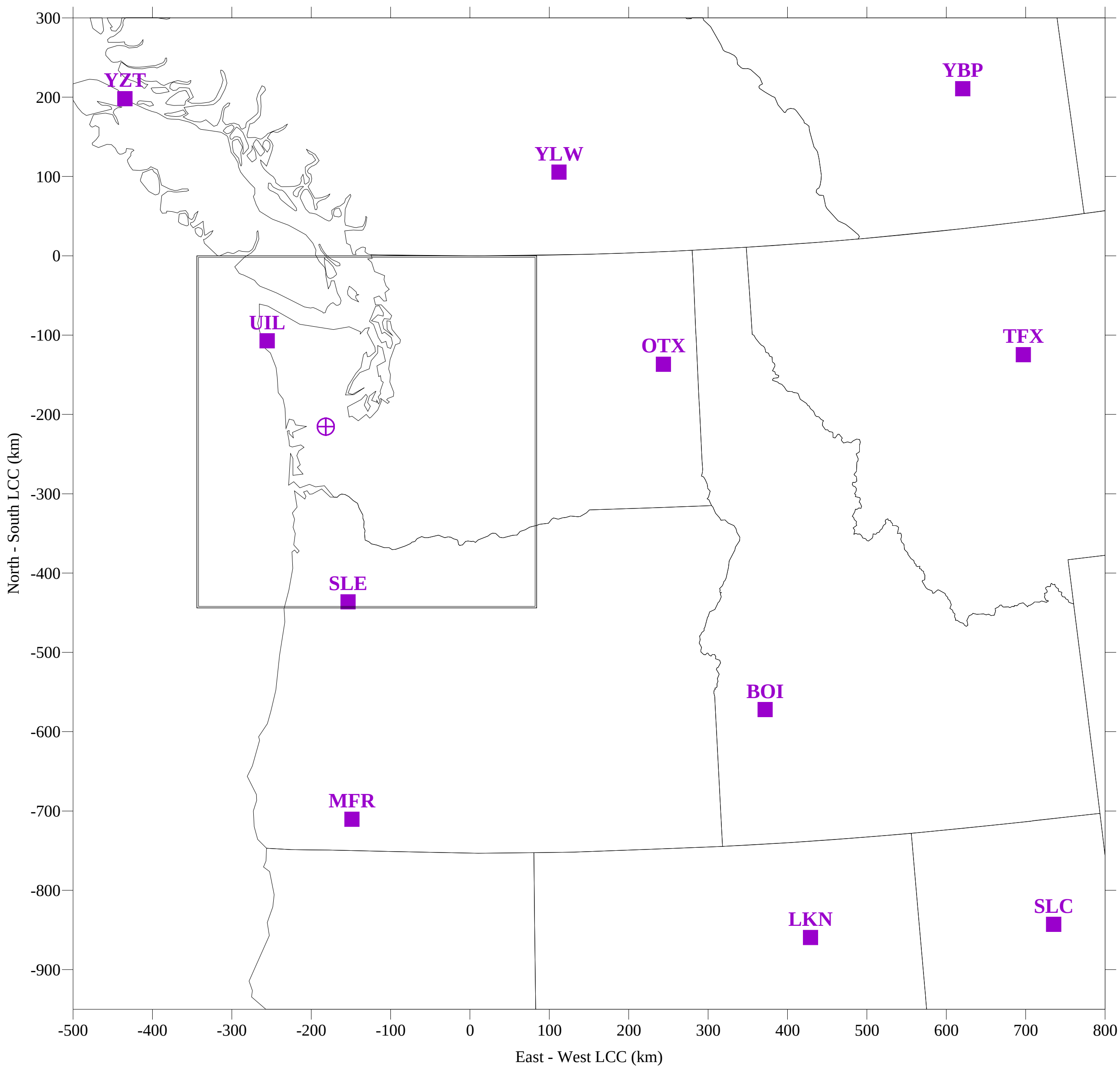


Figure 4-5. Upper Air Meteorological Stations in the Pacific Northwest

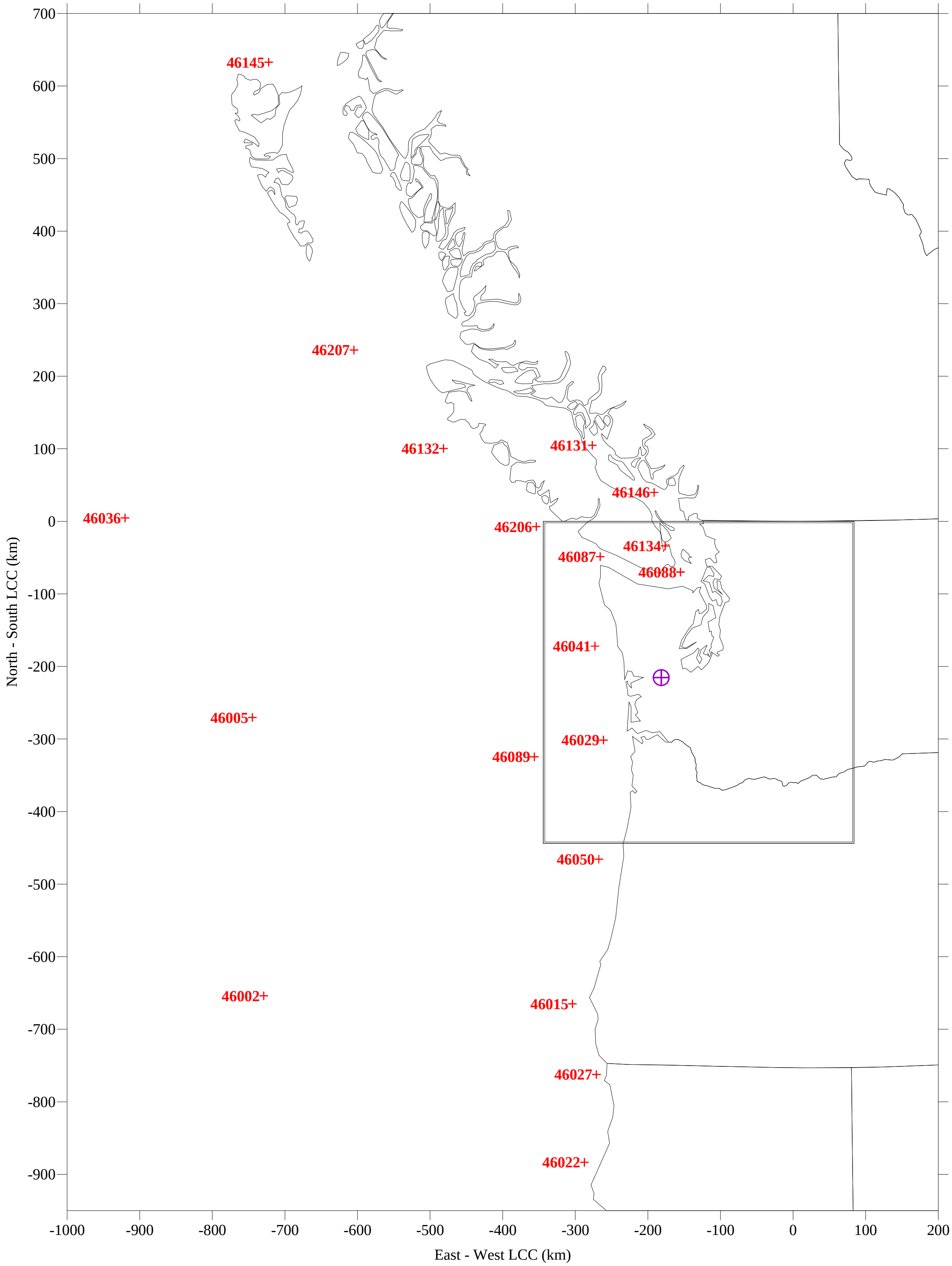


Figure 4-6. Buoy Meteorological Stations in the Pacific Northwest

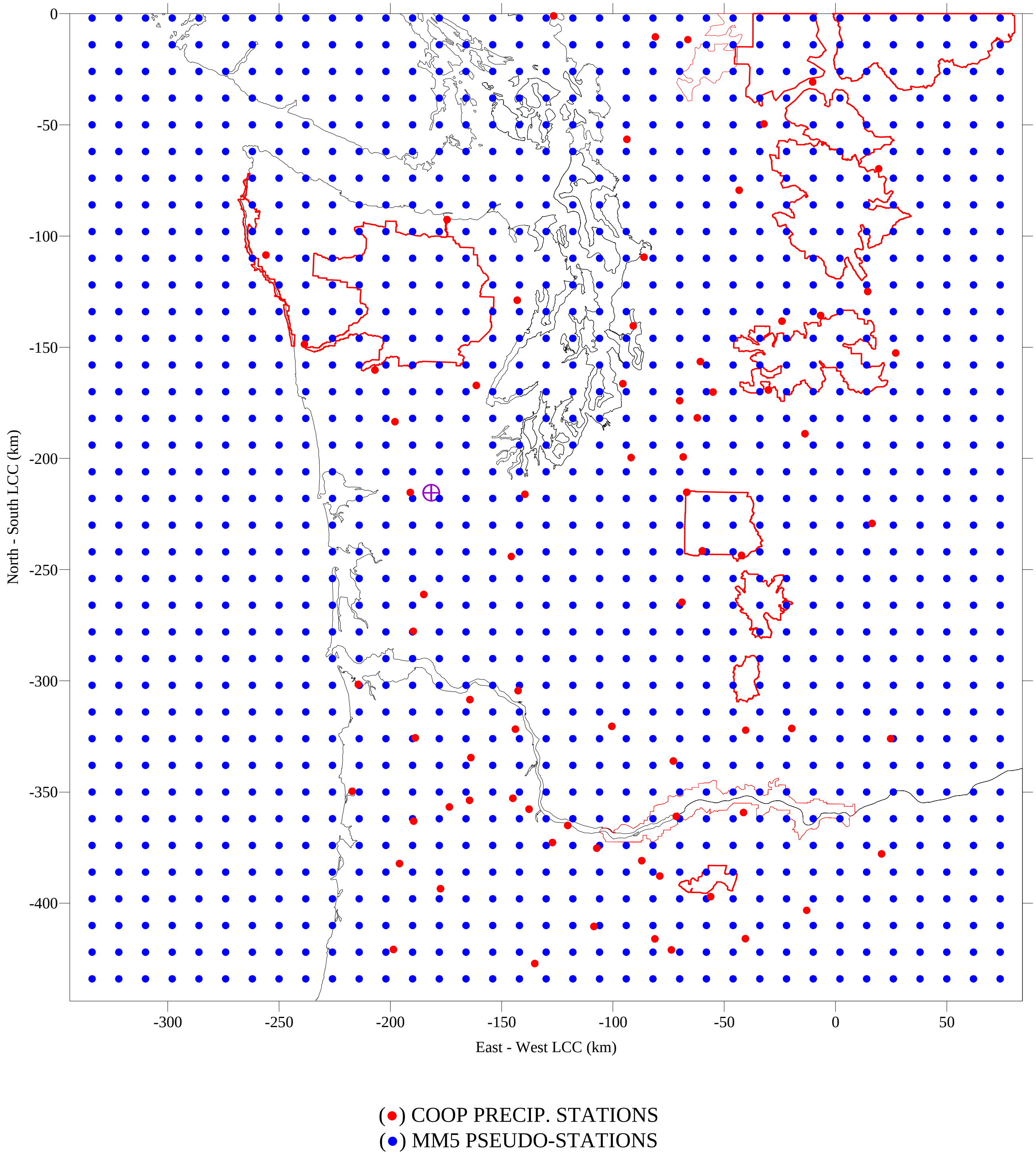
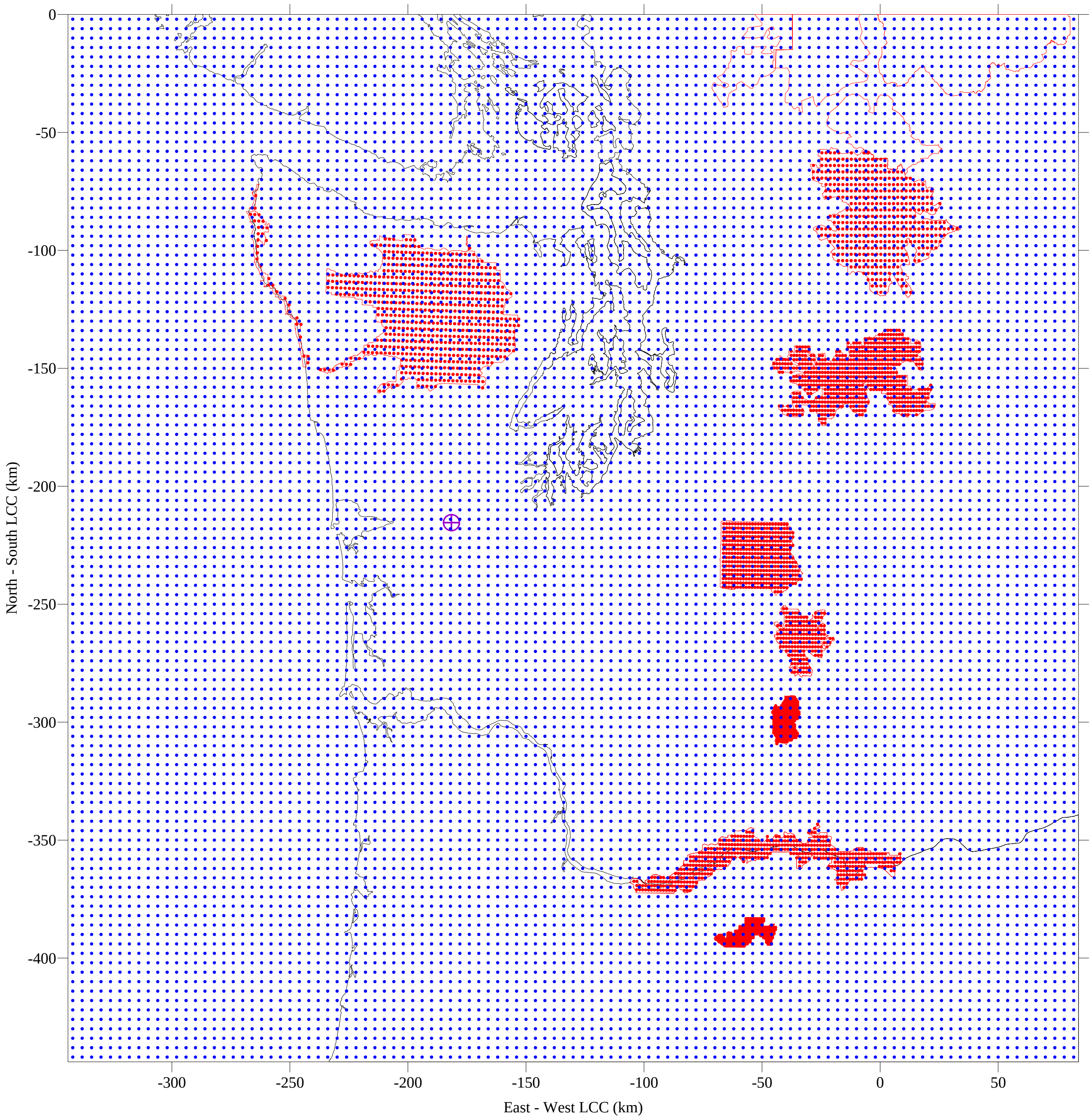


Figure 4-7. CO-OP Precipitation Stations and MM5 Pseudo-Stations



(●) CLASS I/CRGNSA RECEPTORS
(●) GRIDDED RECEPTORS

Figure 4-8. AQRV Analysis Receptors

Appendix A

Satsop Ambient Air & Meteorological Monitoring Annual Data Report (Appendices Removed)

Appendix B

Example CALMET Input File

```
GHE Units 3 & 4 CALMET dataset, 107x111x4km mesh, Jan 2003 4km MM5
Procotol options after comments from FLMs (larger radii and domain)
ds472.0 surface obs, ndbc&bc buoys, mm5 pseudo & coop prec, upa sites
---------------- Run title (3 lines) ------------------------------------------

                    CALMET MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names


Subgroup (a)
------------
Default Name  Type          File Name
------------  ----          ---------
GEO.DAT       input    ! GEODAT= geo/geo.4km.dat    !
SURF.DAT      input    ! SRFDAT= sfc/pacnw.2003.sfc !
CLOUD.DAT     input    * CLDDAT=            *
PRECIP.DAT    input    ! PRCDAT= prec/prec.2003.dat !
WT.DAT        input    * WTDAT=             *

CALMET.LST    output   ! METLST= calmet.2003.01.out  !
CALMET.DAT    output   ! METDAT= calmet.2003.01.met  !
PACOUT.DAT    output   * PACDAT=            *

All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = T !
         F = UPPER CASE

NUMBER OF UPPER AIR & OVERWATER STATIONS:

    Number of upper air stations (NUSTA)  No default     ! NUSTA =  10  !
    Number of overwater met stations
                             (NOWSTA) No default     ! NOWSTA =  20  !

NUMBER OF PROGNOSTIC and IGF-CALMET FILEs:

    Number of MM4/MM5/3D.DAT files
                             (NM3D) No default       ! NM3D =  1  !

    Number of IGF-CALMET.DAT files
                             (NIGF)   No default     ! NIGF =  0  !

                       !END!
--------------------------------------------------------------------------------
Subgroup (b)
---------------------------------
Upper air files (one per station)
---------------------------------
```

```
Default Name  Type       File Name
------------  ----       ---------
UP1.DAT       input     1  ! updat=upa/yzt.2003-2006.upa !    !END!
UP2.DAT       input     1  ! updat=upa/ylw.2003-2006.upa !    !END!
UP3.DAT       input     1  ! updat=upa/mfr.2003-2006.upa !    !END!
UP4.DAT       input     1  ! updat=upa/boi.2003-2006.upa !    !END!
UP5.DAT       input     1  ! updat=upa/sle.2003-2006.upa !    !END!
UP6.DAT       input     1  ! updat=upa/otx.2003-2006.upa !    !END!
UP7.DAT       input     1  ! updat=upa/uil.2003-2006.upa !    !END!
UP8.DAT       input     1  ! updat=upa/tfx.2003-2006.upa !    !END!
UP9.DAT       input     1  ! updat=upa/lkn.2003-2006.upa !    !END!
UP10.DAT      input     1  ! updat=upa/slc.2003-2006.upa !    !END!
--------------------------------------------------------------------------------
Subgroup (c)
-----------------------------------------
Overwater station files (one per station)
-----------------------------------------
Default Name  Type       File Name
------------  ----       ---------
SEA1.DAT       input     *  * SEADAT=4007.DAT*    *END*
                         1  ! seadat=buoy/46002-0305.dat ! !end!
                         2  ! seadat=buoy/46004-0305.dat ! !end!
                         3  ! seadat=buoy/46005-0305.dat ! !end!
                         4  ! seadat=buoy/46006-0305.dat ! !end!
                         5  ! seadat=buoy/46015-0305.dat ! !end!
                         6  ! seadat=buoy/46022-0305.dat ! !end!
                         7  ! seadat=buoy/46027-0305.dat ! !end!
                         8  ! seadat=buoy/46029-0305.dat ! !end!
                         9  ! seadat=buoy/46036-0305.dat ! !end!
                        10  ! seadat=buoy/46041-0305.dat ! !end!
                        11  ! seadat=buoy/46050-0305.dat ! !end!
                        12  ! seadat=buoy/46087-0305.dat ! !end!
                        13  ! seadat=buoy/46088-0305.dat ! !end!
                        14  ! seadat=buoy/46089-0305.dat ! !end!
                        15  ! seadat=buoy/46131-0305.dat ! !end!
                        16  ! seadat=buoy/46132-0305.dat ! !end!
                         *  * seadat=buoy/46134-0305.dat * *end* leave out Pat Bay too
near land and poor data recovery
                        17  ! seadat=buoy/46145-0305.dat ! !end!
                        18  ! seadat=buoy/46146-0305.dat ! !end!
                        19  ! seadat=buoy/46206-0305.dat ! !end!
                        20  ! seadat=buoy/46207-0305.dat ! !end!

--------------------------------------------------------------------------------
Subgroup (d)
------------------------------------------------
MM4/MM5/3D.DAT files (consecutive or overlapping)
------------------------------------------------
Default Name  Type       File Name
------------  ----       ---------
MM51.DAT       input   1 ! M3DDAT=../calmm5/monthly/2003.01.4km.m3d ! !END!
--------------------------------------------------------------------------------
```

```
Subgroup (e)
-------------------------------------------------
IGF-CALMET.DAT files (consecutive or overlapping)
-------------------------------------------------
Default Name  Type       File Name
------------  ----       ---------
IGFn.DAT       input     1  * IGFDAT=CALMET0.DAT *    *END*
--------------------------------------------------------------------------------
Subgroup (f)
----------------
Other file names
----------------

Default Name  Type       File Name
------------  ----       ---------
DIAG.DAT      input      * DIADAT=                  *
PROG.DAT      input      * PRGDAT=                  *

TEST.PRT      output     * TSTPRT=                  *
TEST.OUT      output     * TSTOUT=                  *
TEST.KIN      output     * TSTKIN=                  *
TEST.FRD      output     * TSTFRD=                  *
TEST.SLP      output     * TSTSLP=                  *
DCST.GRD      output     * DCSTGD=                  *

--------------------------------------------------------------------------------
NOTES: (1) File/path names can be up to 70 characters in length
       (2) Subgroups (a) and (f) must have ONE 'END' (surrounded by
           delimiters) at the end of the group
       (3) Subgroups (b) through (e) are included ONLY if the corresponding
           number of files (NUSTA, NOWSTA, NM3D, NIGF) is not 0, and each must have
           an 'END' (surround by delimiters) at the end of EACH LINE

                         !END!


-------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------


     Starting date:   Year (IBYR) -- No default       ! IBYR = 2003  !
                     Month (IBMO) -- No default       ! IBMO = 01 !
                       Day (IBDY) -- No default       ! IBDY = 01 !
                      Hour (IBHR) -- No default       ! IBHR = 01 !

     Note: IBHR is the time at the END of the first hour of the simulation
           (IBHR=1, the first hour of a day, runs from 00:00 to 01:00)

     Base time zone        (IBTZ) -- No default       ! IBTZ = 8  !
        PST = 08, MST = 07
```

```
        CST = 06, EST = 05

     Length of run (hours) (IRLG) -- No default       ! IRLG = 744  !

     Run type            (IRTYPE) -- Default: 1       ! IRTYPE = 1  !

        0 = Computes wind fields only
        1 = Computes wind fields and micrometeorological variables
            (u*, w*, L, zi, etc.)
        (IRTYPE must be 1 to run CALPUFF or CALGRID)

     Compute special data fields required
     by CALGRID (i.e., 3-D fields of W wind
     components and temperature)
     in additional to regular            Default: T    ! LCALGRD = T !
     fields ? (LCALGRD)
     (LCALGRD must be T to run CALGRID)

      Flag to stop run after
      SETUP phase (ITEST)             Default: 2       ! ITEST=  2   !
      (Used to allow checking
      of the model inputs, files, etc.)
      ITEST = 1 - STOPS program after SETUP phase
      ITEST = 2 - Continues with execution of
                  COMPUTATIONAL phase after SETUP


     Test options specified to see if
     they conform to regulatory
     values? (MREG)                   No Default       ! MREG =  1   !

        0 = NO checks are made
        1 = Technical options must conform to USEPA guidance
                  IMIXH    -1       Maul-Carson convective mixing height
                                    over land; OCD mixing height overwater
                  ICOARE   0        OCD deltaT method for overwater fluxes
                  THRESHL  0.0      Threshold buoyancy flux over land needed
                                    to sustain convective mixing height growth

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Map Projection and Grid control parameters
--------------

     Projection for all (X,Y):
     -------------------------

     Map projection
     (PMAP)                      Default: UTM    ! PMAP = LCC  !
```

```
     UTM :  Universal Transverse Mercator
     TTM :  Tangential Transverse Mercator
     LCC :  Lambert Conformal Conic
      PS :  Polar Stereographic
      EM :  Equatorial Mercator
    LAZA :  Lambert Azimuthal Equal Area

False Easting and Northing (km) at the projection origin
(Used only if PMAP= TTM, LCC, or LAZA)
(FEAST)                    Default=0.0      ! FEAST  = 0.000  !
(FNORTH)                   Default=0.0      ! FNORTH = 0.000  !

UTM zone (1 to 60)
(Used only if PMAP=UTM)
(IUTMZN)                   No Default       ! IUTMZN =  -1 !

Hemisphere for UTM projection?
(Used only if PMAP=UTM)
(UTMHEM)                   Default: N       ! UTMHEM = N  !
    N   :  Northern hemisphere projection
    S   :  Southern hemisphere projection

Latitude and Longitude (decimal degrees) of projection origin
(Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
(RLAT0)                    No Default       ! RLAT0 =  49.0N !
(RLON0)                    No Default       ! RLON0 = 121.0W !

    TTM :  RLON0 identifies central (true N/S) meridian of projection
           RLAT0 selected for convenience
    LCC :  RLON0 identifies central (true N/S) meridian of projection
           RLAT0 selected for convenience
    PS  :  RLON0 identifies central (grid N/S) meridian of projection
           RLAT0 selected for convenience
    EM  :  RLON0 identifies central meridian of projection
           RLAT0 is REPLACED by 0.0N (Equator)
    LAZA:  RLON0 identifies longitude of tangent-point of mapping plane
           RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)
(XLAT1)                    No Default       ! XLAT1 = 30.0N !
(XLAT2)                    No Default       ! XLAT2 = 60.0N !

    LCC :  Projection cone slices through Earth's surface at XLAT1 and XLAT2
    PS  :  Projection plane slices through Earth at XLAT1
           (XLAT2 is not used)

----------
Note:  Latitudes and longitudes should be positive, and include a
       letter N,S,E, or W indicating north or south latitude, and
       east or west longitude.  For example,
       35.9  N Latitude  =  35.9N
```

```
       118.7 E Longitude = 118.7E


Datum-region
------------

The Datum-Region for the coordinates is identified by a character
string.  Many mapping products currently available use the model of the
Earth known as the World Geodetic System 1984 (WGS-84).  Other local
models may be in use, and their selection in CALMET will make its output
consistent with local mapping products.  The list of Datum-Regions with
official transformation parameters is provided by the National Imagery and
Mapping Agency (NIMA).

NIMA Datum - Regions(Examples)
------------------------------------------------------------------------------
WGS-84    WGS-84 Reference Ellipsoid and Geoid, Global coverage (WGS84)
NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
NAR-C     NORTH AMERICAN 1983 GRS 80 Spheroid, MEAN FOR CONUS (NAD83)
NWS-84    NWS 6370KM Radius, Sphere
ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

Datum-region for output coordinates
(DATUM)                    Default: WGS-G     ! DATUM = NWS-84  !
                                            *** Same as UW MM5 ***


Horizontal grid definition:
---------------------------

Rectangular grid defined for projection PMAP,
with X the Easting and Y the Northing coordinate

       No. X grid cells (NX)      No default     ! NX =   107  !
       No. Y grid cells (NY)      No default     ! NY =   111  !

Grid spacing (DGRIDKM)            No default     ! DGRIDKM = 4. !
                                  Units: km

Reference grid coordinate of
SOUTHWEST corner of grid cell (1,1)

   X coordinate (XORIGKM)         No default     ! XORIGKM = -344. !
   Y coordinate (YORIGKM)         No default     ! YORIGKM = -444. !
                                  Units: km


Vertical grid definition:
-------------------------

   No. of vertical layers (NZ)    No default     ! NZ = 10 !
```

```
        Cell face heights in arbitrary
        vertical grid (ZFACE(NZ+1))    No defaults
                                       Units: m
        ! ZFACE =0.,20.,40.,65.,120.,200.,400.,700.,1200.,2200.,4000. !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output Options
--------------


    DISK OUTPUT OPTION

       Save met. fields in an unformatted
       output file ?              (LSAVE)  Default: T     ! LSAVE = T !
       (F = Do not save, T = Save)

       Type of unformatted output file:
       (IFORMO)                            Default: 1    ! IFORMO =  1  !

            1 = CALPUFF/CALGRID type file (CALMET.DAT)
            2 = MESOPUFF-II type file     (PACOUT.DAT)


    LINE PRINTER OUTPUT OPTIONS:

       Print met. fields ?  (LPRINT)       Default: F     ! LPRINT = F !
       (F = Do not print, T = Print)
       (NOTE: parameters below control which
              met. variables are printed)

       Print interval
       (IPRINF) in hours                   Default: 1     ! IPRINF = 12  !
       (Meteorological fields are printed
        every  1  hours)


       Specify which layers of U, V wind component
       to print (IUVOUT(NZ)) -- NOTE: NZ values must be entered
       (0=Do not print, 1=Print)
       (used only if LPRINT=T)        Defaults: NZ*0
       ! IUVOUT =  1 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0  !
       -----------------------


       Specify which levels of the W wind component to print
       (NOTE: W defined at TOP cell face --  6  values)
       (IWOUT(NZ)) -- NOTE: NZ values must be entered
       (0=Do not print, 1=Print)
```

```
(used only if LPRINT=T & LCALGRD=T)
-----------------------------------
                                    Defaults: NZ*0
 ! IWOUT =  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0  !


Specify which levels of the 3-D temperature field to print
(ITOUT(NZ)) -- NOTE: NZ values must be entered
(0=Do not print, 1=Print)
(used only if LPRINT=T & LCALGRD=T)
-----------------------------------
                                    Defaults: NZ*0
 ! ITOUT =  1 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0 ,  0  !

Specify which meteorological fields
to print
(used only if LPRINT=T)            Defaults: 0 (all variables)
-----------------------


  Variable            Print ?
                  (0 = do not print,
                   1 = print)
  --------        ------------------

!  STABILITY  =          1           ! - PGT stability class
!  USTAR      =          0           ! - Friction velocity
!  MONIN      =          0           ! - Monin-Obukhov length
!  MIXHT      =          1           ! - Mixing height
!  WSTAR      =          0           ! - Convective velocity scale
!  PRECIP     =          1           ! - Precipitation rate
!  SENSHEAT   =          0           ! - Sensible heat flux
!  CONVZI     =          0           ! - Convective mixing ht.


Testing and debug print options for micrometeorological module

   Print input meteorological data and
   internal variables (LDB)         Default: F       ! LDB = F !
   (F = Do not print, T = print)
   (NOTE: this option produces large amounts of output)

   First time step for which debug data
   are printed (NN1)                Default: 1       ! NN1 =  1  !

   Last time step for which debug data
   are printed (NN2)                Default: 1       ! NN2 =  1  !

   Print distance to land
   internal variables (LDBCST)      Default: F       ! LDBCST = F !
   (F = Do not print, T = print)
   (Output in .GRD file DCST.GRD, defined in input group 0)
```

```
       Testing and debug print options for wind field module
       (all of the following print options control output to
        wind field module's output files: TEST.PRT, TEST.OUT,
        TEST.KIN, TEST.FRD, and TEST.SLP)

          Control variable for writing the test/debug
          wind fields to disk files (IOUTD)
          (0=Do not write, 1=write)        Default: 0       ! IOUTD =  0  !

          Number of levels, starting at the surface,
          to print (NZPRN2)                Default: 1       ! NZPRN2 =  1  !

          Print the INTERPOLATED wind components ?
          (IPR0) (0=no, 1=yes)             Default: 0       !  IPR0 =  0  !

          Print the TERRAIN ADJUSTED surface wind
          components ?
          (IPR1) (0=no, 1=yes)             Default: 0       !  IPR1 =  0  !

          Print the SMOOTHED wind components and
          the INITIAL DIVERGENCE fields ?
          (IPR2) (0=no, 1=yes)             Default: 0       !  IPR2 =  0  !

          Print the FINAL wind speed and direction
          fields ?
          (IPR3) (0=no, 1=yes)             Default: 0       !  IPR3 =  0  !

          Print the FINAL DIVERGENCE fields ?
          (IPR4) (0=no, 1=yes)             Default: 0       !  IPR4 =  0  !

          Print the winds after KINEMATIC effects
          are added ?
          (IPR5) (0=no, 1=yes)             Default: 0       !  IPR5 =  0  !

          Print the winds after the FROUDE NUMBER
          adjustment is made ?
          (IPR6) (0=no, 1=yes)             Default: 0       !  IPR6 =  0  !

          Print the winds after SLOPE FLOWS
          are added ?
          (IPR7) (0=no, 1=yes)             Default: 0       !  IPR7 =  0  !

          Print the FINAL wind field components ?
          (IPR8) (0=no, 1=yes)             Default: 0       !  IPR8 =  0  !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 4 -- Meteorological data options
```

```
--------------

    NO OBSERVATION MODE             (NOOBS)  Default: 0     ! NOOBS =  0   !
          0 = Use surface, overwater, and upper air stations
          1 = Use surface and overwater stations (no upper air observations)
              Use MM4/MM5/3D for upper air data
          2 = No surface, overwater, or upper air observations
              Use MM4/MM5/3D for surface, overwater, and upper air data

    NUMBER OF SURFACE & PRECIP. METEOROLOGICAL STATIONS

       Number of surface stations   (NSSTA)  No default     ! NSSTA = 115  !

       Number of precipitation stations
       (NPSTA=-1: flag for use of MM5/3D precip data)
                                    (NPSTA)  No default     ! NPSTA = 1398  !

    CLOUD DATA OPTIONS
       Gridded cloud fields:
                                   (ICLOUD)  Default: 0     ! ICLOUD =  0  !
       ICLOUD = 0 - Gridded clouds not used
       ICLOUD = 1 - Gridded CLOUD.DAT generated as OUTPUT
       ICLOUD = 2 - Gridded CLOUD.DAT read as INPUT
       ICLOUD = 3 - Gridded cloud cover computed from prognostic fields

    FILE FORMATS

       Surface meteorological data file format
                                   (IFORMS)  Default: 2     ! IFORMS =  2  !
       (1 = unformatted (e.g., SMERGE output))
       (2 = formatted   (free-formatted user input))

       Precipitation data file format
                                   (IFORMP)  Default: 2     ! IFORMP =  2  !
       (1 = unformatted (e.g., PMERGE output))
       (2 = formatted   (free-formatted user input))

       Cloud data file format
                                   (IFORMC)  Default: 2     ! IFORMC =  2  !
       (1 = unformatted - CALMET unformatted output)
       (2 = formatted   - free-formatted CALMET output or user input)

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 5 -- Wind Field Options and Parameters
--------------


    WIND FIELD MODEL OPTIONS
```

```
Model selection variable (IWFCOD)     Default: 1      ! IWFCOD =  1  !
   0 = Objective analysis only
   1 = Diagnostic wind module

Compute Froude number adjustment
effects ? (IFRADJ)                    Default: 1      ! IFRADJ =  1  !
(0 = NO, 1 = YES)

Compute kinematic effects ? (IKINE)   Default: 0      ! IKINE  =  0  !
(0 = NO, 1 = YES)

Use O'Brien procedure for adjustment
of the vertical velocity ? (IOBR)     Default: 0      ! IOBR =  0  !
(0 = NO, 1 = YES)

Compute slope flow effects ? (ISLOPE) Default: 1      ! ISLOPE  =  1  !
(0 = NO, 1 = YES)

Extrapolate surface wind observations
to upper layers ? (IEXTRP)            Default: -4     ! IEXTRP = -4  !
(1 = no extrapolation is done,
 2 = power law extrapolation used,
 3 = user input multiplicative factors
     for layers 2 - NZ used (see FEXTRP array)
 4 = similarity theory used
 -1, -2, -3, -4 = same as above except layer 1 data
     at upper air stations are ignored

Extrapolate surface winds even
if calm? (ICALM)                      Default: 0      ! ICALM  =  0  !
(0 = NO, 1 = YES)

Layer-dependent biases modifying the weights of
surface and upper air stations (BIAS(NZ))
  -1<=BIAS<=1
Negative BIAS reduces the weight of upper air stations
  (e.g. BIAS=-0.1 reduces the weight of upper air stations
by 10%; BIAS= -1, reduces their weight by 100 %)
Positive BIAS reduces the weight of surface stations
  (e.g. BIAS= 0.2 reduces the weight of surface stations
by 20%; BIAS=1 reduces their weight by 100%)
Zero BIAS leaves weights unchanged (1/R**2 interpolation)
Default: NZ*0
         *BIAS =  -1 ,  1 ,  1 ,  1 ,  1 ,  1 ,  1 ,  1 ,  1 ,  1  *
         ! BIAS =  10*0 !

Minimum distance from nearest upper air station
to surface station for which extrapolation
of surface winds at surface station will be allowed
(RMIN2: Set to -1 for IEXTRP = 4 or other situations
 where all surface stations should be extrapolated)
                                      Default: 4.     ! RMIN2 = -1.0 !
```

```
   Use gridded prognostic wind field model
   output fields as input to the diagnostic
   wind field model (IPROG)             Default: 0      ! IPROG =  14  !
   (0 = No, [IWFCOD = 0 or 1]
    1 = Yes, use CSUMM prog. winds as Step 1 field, [IWFCOD = 0]
    2 = Yes, use CSUMM prog. winds as initial guess field [IWFCOD = 1]
    3 = Yes, use winds from MM4.DAT file as Step 1 field [IWFCOD = 0]
    4 = Yes, use winds from MM4.DAT file as initial guess field [IWFCOD = 1]
    5 = Yes, use winds from MM4.DAT file as observations [IWFCOD = 1]
    13 = Yes, use winds from MM5/3D.DAT file as Step 1 field [IWFCOD = 0]
    14 = Yes, use winds from MM5/3D.DAT file as initial guess field [IWFCOD = 1]
    15 = Yes, use winds from MM5/3D.DAT file as observations [IWFCOD = 1]

   Timestep (hours) of the prognostic
   model input data   (ISTEPPG)         Default: 1      ! ISTEPPG =  1   !

   Use coarse CALMET fields as initial guess fields (IGFMET)
   (overwrites IGF based on prognostic wind fields if any)
                                        Default: 0      ! IGFMET =  0  !

RADIUS OF INFLUENCE PARAMETERS

   Use varying radius of influence      Default: F      ! LVARY =  F !
   (if no stations are found within RMAX1,RMAX2,
    or RMAX3, then the closest station will be used)

   Maximum radius of influence over land
   in the surface layer (RMAX1)         No default      ! RMAX1 =  36. !
                                        Units: km
   Maximum radius of influence over land
   aloft (RMAX2)                        No default      ! RMAX2 =  36. !
                                        Units: km
   Maximum radius of influence over water
   (RMAX3)                              No default      ! RMAX3 =  50. !


OTHER WIND FIELD INPUT PARAMETERS

   Minimum radius of influence used in
   the wind field interpolation (RMIN)  Default: 0.1    ! RMIN = 0.1 !
                                        Units: km
   Radius of influence of terrain
   features (TERRAD)                    No default      ! TERRAD = 8. !

                                        Units: km
   Relative weighting of the first
   guess field and observations in the
   SURFACE layer (R1)                   No default      ! R1 = 10. !
   (R1 is the distance from an          Units: km
   observational station at which the
   observation and first guess field are
```

```
   equally weighted)

   Relative weighting of the first
   guess field and observations in the
   layers ALOFT (R2)                     No default      ! R2 = 10. !
   (R2 is applied in the upper layers    Units: km
   in the same manner as R1 is used in
   the surface layer).

   Relative weighting parameter of the
   prognostic wind field data (RPROG)    No default      ! RPROG = 0. !
   (Used only if IPROG = 1)              Units: km
   ------------------------

   Maximum acceptable divergence in the
   divergence minimization procedure
   (DIVLIM)                              Default: 5.E-6  ! DIVLIM= 5.0E-06 !

   Maximum number of iterations in the
   divergence min. procedure (NITER)     Default: 50     ! NITER =  50  !

   Number of passes in the smoothing
   procedure (NSMTH(NZ))
   NOTE: NZ values must be entered
        Default: 2,(mxnz-1)*4

   ! NSMTH =  1 ,  2 ,  2 ,  3 ,  3 ,  4 ,  4 ,  4 ,  4 ,  4  !

   Maximum number of stations used in
   each layer for the interpolation of
   data to a grid point (NINTR2(NZ))
   NOTE: NZ values must be entered       Default: 99.

   ! NINTR2 =  99,  99,  99,  99,  99,  99,  99,  99,  99,  99  !

   Critical Froude number (CRITFN)       Default: 1.0    ! CRITFN = 1. !

   Empirical factor controlling the
   influence of kinematic effects
   (ALPHA)                               Default: 0.1    ! ALPHA = 0.1 !

   Multiplicative scaling factor for
   extrapolation of surface observations
   to upper layers (FEXTR2(NZ))          Default: NZ*0.0
   ! FEXTR2 = 0., 0., 0., 0., 0., 0., 0., 0., 0., 0. !
   (Used only if IEXTRP = 3 or -3)


BARRIER INFORMATION

   Number of barriers to interpolation
   of the wind fields (NBAR)             Default: 0      ! NBAR =  0  !
```

```
      Level (1 to NZ) up to which barriers
      apply (KBAR)                         Default: NZ     ! KBAR =  10  !

      THE FOLLOWING 4 VARIABLES ARE INCLUDED
      ONLY IF NBAR > 0
      NOTE: NBAR values must be entered    No defaults
            for each variable              Units: km

         X coordinate of BEGINNING
         of each barrier (XBBAR(NBAR))      ! XBBAR = 0. !
         Y coordinate of BEGINNING
         of each barrier (YBBAR(NBAR))      ! YBBAR = 0. !

         X coordinate of ENDING
         of each barrier (XEBAR(NBAR))      ! XEBAR = 0. !
         Y coordinate of ENDING
         of each barrier (YEBAR(NBAR))      ! YEBAR = 0. !


   DIAGNOSTIC MODULE DATA INPUT OPTIONS

      Surface temperature (IDIOPT1)         Default: 0      ! IDIOPT1 =  0  !
         0 = Compute internally from
             hourly surface observations
         1 = Read preprocessed values from
             a data file (DIAG.DAT)

         Surface met. station to use for
         the surface temperature (ISURFT)   No default     ! ISURFT = 98 ! SeaTac
         (Must be a value from 1 to NSSTA)
         (Used only if IDIOPT1 = 0)
         --------------------------

      Domain-averaged temperature lapse
      rate (IDIOPT2)                        Default: 0     ! IDIOPT2 =  0  !
         0 = Compute internally from
             twice-daily upper air observations
         1 = Read hourly preprocessed values
             from a data file (DIAG.DAT)

         Upper air station to use for
         the domain-scale lapse rate (IUPT) No default     ! IUPT   =  8  !
Quillayute
         (Must be a value from 1 to NUSTA)
         (Used only if IDIOPT2 = 0)
         --------------------------

         Depth through which the domain-scale
         lapse rate is computed (ZUPT)      Default: 200.  ! ZUPT = 200. !
         (Used only if IDIOPT2 = 0)         Units: meters
         --------------------------
```

```
Domain-averaged wind components
(IDIOPT3)                             Default: 0     ! IDIOPT3 =  0  !
   0 = Compute internally from
       twice-daily upper air observations
   1 = Read hourly preprocessed values
       a data file (DIAG.DAT)

   Upper air station to use for
   the domain-scale winds (IUPWND)    Default: -1    ! IUPWND = -1  !
   (Must be a value from -1 to NUSTA)
   (Used only if IDIOPT3 = 0)
   --------------------------

   Bottom and top of layer through
   which the domain-scale winds
   are computed
   (ZUPWND(1), ZUPWND(2))        Defaults: 1., 1000. ! ZUPWND= 1., 1000. !
   (Used only if IDIOPT3 = 0)    Units: meters
   --------------------------

Observed surface wind components
for wind field module (IDIOPT4)  Default: 0     ! IDIOPT4 =  0  !
   0 = Read WS, WD from a surface
       data file (SURF.DAT)
   1 = Read hourly preprocessed U, V from
       a data file (DIAG.DAT)

Observed upper air wind components
for wind field module (IDIOPT5)  Default: 0     ! IDIOPT5 =  0  !
   0 = Read WS, WD from an upper
       air data file (UP1.DAT, UP2.DAT, etc.)
   1 = Read hourly preprocessed U, V from
       a data file (DIAG.DAT)

LAKE BREEZE INFORMATION

   Use Lake Breeze Module  (LLBREZE)
                                   Default: F      ! LLBREZE = F !

    Number of lake breeze regions (NBOX)            ! NBOX =  0  !

 X Grid line 1 defining the region of interest
                                                ! XG1 = 0. !
 X Grid line 2 defining the region of interest
                                                ! XG2 = 0. !
 Y Grid line 1 defining the region of interest
                                                ! YG1 = 0. !
 Y Grid line 2 defining the region of interest
                                                ! YG2 = 0. !

  X Point defining the coastline (Straight line)
```

```
                (XBCST)  (KM)   Default: none    ! XBCST = 0. !

          Y Point defining the coastline (Straight line)
                (YBCST)  (KM)   Default: none    ! YBCST = 0. !

          X Point defining the coastline (Straight line)
                (XECST)  (KM)   Default: none    ! XECST = 0. !

          Y Point defining the coastline (Straight line)
                (YECST)  (KM)   Default: none    ! YECST = 0. !


        Number of stations in the region     Default: none ! NLB =  0 !
        (Surface stations + upper air stations)

        Station ID's  in the region   (METBXID(NLB))
        (Surface stations first, then upper air stations)
          ! METBXID =  0 !

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 6 -- Mixing Height, Temperature and Precipitation Parameters
--------------

    EMPIRICAL MIXING HEIGHT CONSTANTS

       Neutral, mechanical equation
       (CONSTB)                              Default: 1.41   ! CONSTB = 1.41 !
       Convective mixing ht. equation
       (CONSTE)                              Default: 0.15   ! CONSTE = 0.15 !
       Stable mixing ht. equation
       (CONSTN)                              Default: 2400.  ! CONSTN = 2400.!
       Overwater mixing ht. equation
       (CONSTW)                              Default: 0.16   ! CONSTW = 0.16 !
       Absolute value of Coriolis
       parameter (FCORIOL)                   Default: 1.E-4  ! FCORIOL = 1.0E-04!
                                             Units: (1/s)

    SPATIAL AVERAGING OF MIXING HEIGHTS

       Conduct spatial averaging
       (IAVEZI)  (0=no, 1=yes)               Default: 1      ! IAVEZI =  1  !

       Max. search radius in averaging
       process (MNMDAV)                      Default: 1      ! MNMDAV =  1  !
                                             Units: Grid
                                                    cells
       Half-angle of upwind looking cone
       for averaging (HAFANG)                Default: 30.    ! HAFANG = 30. !
```

```
                                      Units: deg.
   Layer of winds used in upwind
   averaging (ILEVZI)                 Default: 1      ! ILEVZI =  1  !
   (must be between 1 and NZ)


CONVECTIVE MIXING HEIGHT OPTIONS:
   Method to compute the convective
   mixing height(IMIHXH)              Default: 1      ! IMIXH =  -1  !
       1: Maul-Carson for land and water cells
      -1: Maul-Carson for land cells only -
          OCD mixing height overwater
       2: Batchvarova and Gryning for land and water cells
      -2: Batchvarova and Gryning for land cells only
          OCD mixing height overwater

   Threshold buoyancy flux required to
   sustain convective mixing height growth
   overland (THRESHL)                 Default: 0.0    ! THRESHL = 0.0 !
   (expressed as a heat flux          units: W/m3
    per meter of boundary layer)


   Threshold buoyancy flux required to
   sustain convective mixing height growth
   overwater (THRESHW)                Default: 0.05   ! THRESHW = 0.05 !
   (expressed as a heat flux          units: W/m3
    per meter of boundary layer)


   Option for overwater lapse rates used
   in convective mixing height growth
   (ITWPROG)                          Default: 0      ! ITWPROG =  0  !
   0 : use SEA.DAT lapse rates and deltaT (or assume neutral
       conditions if missing)
   1 : use prognostic lapse rates (only if IPROG>2)
       and SEA.DAT deltaT (or neutral if missing)
   2 : use prognostic lapse rates and prognostic delta T
       (only if iprog>12 and 3D.DAT version# 2.0 or higher)

   Land Use category ocean in 3D.DAT datasets
   (ILUOC3D)                          Default: 16     ! ILUOC3D =  16  !
   Note: if 3D.DAT from MM5 version 3.0, iluoc3d = 16
         if MM4.DAT,           typically iluoc3d = 7


OTHER MIXING HEIGHT VARIABLES

   Minimum potential temperature lapse
   rate in the stable layer above the
   current convective mixing ht.      Default: 0.001  ! DPTMIN = 0.001 !
   (DPTMIN)                           Units: deg. K/m
```

```
   Depth of layer above current conv.
   mixing height through which lapse     Default: 200.   ! DZZI = 200.   !
   rate is computed (DZZI)               Units: meters

   Minimum overland mixing height        Default:  50.   ! ZIMIN = 50.   !
   (ZIMIN)                               Units: meters
   Maximum overland mixing height        Default: 3000.  ! ZIMAX = 3000. !
   (ZIMAX)                               Units: meters
   Minimum overwater mixing height       Default:   50.  ! ZIMINW = 50.  !
   (ZIMINW) -- (Not used if observed     Units: meters
   overwater mixing hts. are used)
   Maximum overwater mixing height       Default: 3000.  ! ZIMAXW = 3000.!
   (ZIMAXW) -- (Not used if observed     Units: meters
   overwater mixing hts. are used)


OVERWATER SURFACE FLUXES METHOD and PARAMETERS
      (ICOARE)                           Default: 10      ! ICOARE =  0   !
       0: original deltaT method (OCD)
      10: COARE with no wave parameterization (jwave=0, Charnock)
      11: COARE with wave option jwave=1 (Oost et al.)
          and default wave properties
     -11: COARE with wave option jwave=1 (Oost et al.)
          and observed wave properties (must be in SEA.DAT files)
      12: COARE with wave option 2 (Taylor and Yelland)
           and default wave properties
     -12: COARE with wave option 2 (Taylor and Yelland)
          and observed wave properties (must be in SEA.DAT files)

      Note:  When ICOARE=0, similarity wind profile stability PSI functions
             based on Van Ulden and Holtslag (1985) are substituted for
             later formulations used with the COARE module, and temperatures
             used for surface layer parameters are obtained from either the
             nearest surface station temperature or prognostic model 2D
             temperatures (if ITPROG=2).

      Coastal/Shallow water length scale (DSHELF)
      (for modified z0 in shallow water)
      ( COARE fluxes only)
                                      Default : 0.        ! DSHELF = 0. !
                                      units: km

       COARE warm layer computation (IWARM)               ! IWARM =  0   !
       1: on - 0: off (must be off if SST measured with
       IR radiometer)                 Default: 0

       COARE cool skin layer computation (ICOOL)          ! ICOOL =  0   !
       1: on - 0: off (must be off if SST measured with
       IR radiometer)                 Default: 0


TEMPERATURE PARAMETERS
```

```
      3D temperature from observations or
      from prognostic data? (ITPROG)        Default:0        ! ITPROG =  0  !

         0 = Use Surface and upper air stations
             (only if NOOBS = 0)
         1 = Use Surface stations (no upper air observations)
             Use MM5/3D for upper air data
             (only if NOOBS = 0,1)
         2 = No surface or upper air observations
             Use MM5/3D for surface and upper air data
             (only if NOOBS = 0,1,2)

      Interpolation type
      (1 = 1/R ; 2 = 1/R**2)                Default:1         ! IRAD =  1  !

      Radius of influence for temperature
      interpolation (TRADKM)                Default: 500.     ! TRADKM = 500. !
                                            Units: km

      Maximum Number of stations to include
      in temperature interpolation (NUMTS)  Default: 5        ! NUMTS = 5  !

      Conduct spatial averaging of temp-
      eratures (IAVET)  (0=no, 1=yes)       Default: 1        ! IAVET =  1  !
      (will use mixing ht MNMDAV,HAFANG
       so make sure they are correct)

      Default temperature gradient          Default: -.0098   ! TGDEFB = -0.0098 !
      below the mixing height over          Units: K/m
      water (TGDEFB)

      Default temperature gradient          Default: -.0045   ! TGDEFA = -0.0045 !
      above the mixing height over          Units: K/m
      water (TGDEFA)

      Beginning (JWAT1) and ending (JWAT2)
      land use categories for temperature            ! JWAT1 =  55  !
      interpolation over water -- Make               ! JWAT2 =  55  !
      bigger than largest land use to disable

  PRECIP INTERPOLATION PARAMETERS

      Method of interpolation (NFLAGP)      Default: 2       ! NFLAGP =  2  !
       (1=1/R,2=1/R**2,3=EXP/R**2)
      Radius of Influence  (SIGMAP)         Default: 100.0   ! SIGMAP  = 12.  !   mm5
pseudo prec mesh size
       (0.0 => use half dist. btwn          Units: km
        nearest stns w & w/out
        precip when NFLAGP = 3)
      Minimum Precip. Rate Cutoff (CUTP)    Default: 0.01    ! CUTP = 0.01 !
       (values < CUTP = 0.0 mm/hr)          Units: mm/hr
```

```
!END!


-------------------------------------------------------------------------------

INPUT GROUP: 7 -- Surface meteorological station parameters
--------------

     SURFACE STATION VARIABLES
     (One record per station --  NSSTA  records in all)


             1      2
         Name    ID            X coord.    Y coord.    Time   Anem.
                                (km)        (km)       zone   Ht.(m)
       ----------------------------------------------------------
! SS1  ='CWCL'  714740     -33.918     231.620  8 10.0 !
! SS2  ='CWLY'  718910     -40.254     132.822  8 10.0 !
! SS3  ='CYKA'  718870      37.462     183.122  8 10.0 !
! SS4  ='CYLW'  712030     111.894     105.162  8 10.0 !
! SS5  ='CYQL'  718740     570.501      97.322  8 10.0 !
! SS6  ='CYQQ'  718930    -271.390      83.727  8 10.0 !
! SS7  ='CYRV'  718820     191.179     215.143  8 10.0 !
! SS8  ='CYVR'  718920    -153.554      21.755  8 10.0 !
! SS9  ='CYXC'  718800     363.423      78.204  8 10.0 !
! SS10 ='CYXH'  718720     709.434     155.038  8 10.0 !
! SS11 ='CYXX'  711080     -96.471       4.353  8 10.0 !
! SS12 ='CYYC'  718770     472.126     248.559  8 10.0 !
! SS13 ='CYYF'  718890      97.809      51.071  8 10.0 !
! SS14 ='CYYJ'  717990    -172.866     -35.027  8 10.0 !
! SS15 ='CYYN'  718700     912.324     214.112  8 10.0 !
! SS16 ='CYZT'  711090    -434.451     198.439  8 10.0 !
! SS17 ='CZPC'  718755     489.505      77.062  8 10.0 !
! SS18 ='KAAT'   94264      35.069    -806.671  8 10.0 !
! SS19 ='KACV'  725495    -252.603    -856.997  8 10.0 !
! SS20 ='KALW'   24160     202.148    -308.127  8 10.0 !
! SS21 ='KAST'  727910    -214.477    -302.331  8 10.0 !
! SS22 ='KAWO'  727945     -83.937     -88.631  8 10.0 !
! SS23 ='KBFI'   24234     -94.365    -156.915  8 10.0 !
! SS24 ='KBKE'  726886     242.788    -441.671  8 10.0 !
! SS25 ='KBLI'   24217    -108.653     -20.486  8 10.0 !
! SS26 ='KBNO'  726830     159.432    -579.787  8 10.0 !
! SS27 ='KBOI'  726810     372.019    -572.431  8 10.0 !
! SS28 ='KBPI'  726710     860.378    -632.360  8 10.0 !
! SS29 ='KBTM'  726785     632.986    -292.422  8 10.0 !
! SS30 ='KBYI'  725867     572.209    -667.836  8 10.0 !
! SS31 ='KBZN'   24132     735.544    -300.287  8 10.0 !
! SS32 ='KCEC'  725946    -259.428    -770.105  8 10.0 !
! SS33 ='KCLM'   94266    -179.410     -92.139  8 10.0 !
! SS34 ='KCOD'  726700     914.025    -412.987  8 10.0 !
! SS35 ='KCOE'   24136     301.836    -124.656  8 10.0 !
! SS36 ='KCTB'  727796     611.146      -8.278  8 10.0 !
```

```
! SS37 ='KCVO'   24202    -174.922    -480.848  8 10.0 !
! SS38 ='KDEW'      97     258.087    -104.945  8 10.0 !
! SS39 ='KDLN'   24138     637.435    -369.143  8 10.0 !
! SS40 ='KDLS'  726988     -12.926    -363.185  8 10.0 !
! SS41 ='KEAT'  727825      58.006    -171.891  8 10.0 !
! SS42 ='KEKO'  725825     424.608    -864.548  8 10.0 !
! SS43 ='KELN'   24220      35.289    -214.818  8 10.0 !
! SS44 ='KENV'  725810     568.059    -863.665  8 10.0 !
! SS45 ='KEPH'  727826     108.056    -180.845  8 10.0 !
! SS46 ='KEUG'  726930    -171.008    -522.104  8 10.0 !
! SS47 ='KEUL'  726813     339.553    -567.509  8 10.0 !
! SS48 ='KEVW'   94156     804.462    -779.876  8 10.0 !
! SS49 ='KFCA'  727790     480.729     -55.045  8 10.0 !
! SS50 ='KFHR'   94276    -143.690     -50.141  8 10.0 !
! SS51 ='KGEG'  727850     250.815    -141.506  8 10.0 !
! SS52 ='KGTF'  727750     697.509    -121.037  8 10.0 !
! SS53 ='KHIO'   94261    -146.987    -369.028  8 10.0 !
! SS54 ='KHLN'  727720     662.505    -220.599  8 10.0 !
! SS55 ='KHQM'  727923    -214.737    -213.896  8 10.0 !
! SS56 ='KHRI'     118     130.006    -339.562  8 10.0 !
! SS57 ='KHVR'  727770     796.639       7.576  8 10.0 !
! SS58 ='KIDA'   24145     694.449    -550.137  8 10.0 !
! SS59 ='KJAC'   24166     796.494    -528.863  8 10.0 !
! SS60 ='KJER'     122     516.353    -652.584  8 10.0 !
! SS61 ='KKLS'     123    -141.478    -308.056  8 10.0 !
! SS62 ='KLGU'   94128     732.505    -733.438  8 10.0 !
! SS63 ='KLKV'     126      47.747    -733.852  8 10.0 !
! SS64 ='KLLJ'  727833     518.664    -459.530  8 10.0 !
! SS65 ='KLMT'   94236     -58.539    -735.592  8 10.0 !
! SS66 ='KLVM'  726798     789.397    -302.586  8 10.0 !
! SS67 ='KLWS'  727830     294.803    -273.839  8 10.0 !
! SS68 ='KLWT'  726776     840.903    -148.884  8 10.0 !
! SS69 ='KMEH'   24152     195.533    -372.798  8 10.0 !
! SS70 ='KMFR'  725970    -148.414    -710.793  8 10.0 !
! SS71 ='KMHS'   24215    -106.581    -824.622  8 10.0 !
! SS72 ='KMLP'     135     386.752    -153.286  8 10.0 !
! SS73 ='KMMV'     136    -161.372    -406.464  8 10.0 !
! SS74 ='KMSO'  727730     506.654    -201.936  8 10.0 !
! SS75 ='KMWH'   24110     122.716    -192.156  8 10.0 !
! SS76 ='KMYL'   94182     372.467    -430.814  8 10.0 !
! SS77 ='KNUW'   24255    -117.935     -68.685  8 10.0 !
! SS78 ='KOGD'   24126     726.421    -799.131  8 10.0 !
! SS79 ='KOLM'  727920    -139.313    -216.816  8 10.0 !
! SS80 ='KOMK'  727890     105.473     -56.993  8 10.0 !
! SS81 ='KONO'   24162     307.434    -527.561  8 10.0 !
! SS82 ='KONP'   24285    -233.296    -469.986  8 10.0 !
! SS83 ='KOTH'   24284    -253.662    -594.516  8 10.0 !
! SS84 ='KPAE'   24222     -92.470    -115.688  8 10.0 !
! SS85 ='KPDT'  726880     161.158    -354.163  8 10.0 !
! SS86 ='KPDX'  726980    -120.265    -364.038  8 10.0 !
! SS87 ='KPIH'  725780     659.917    -618.742  8 10.0 !
! SS88 ='KPSC'   24163     139.663    -291.986  8 10.0 !
```

```
! SS89 ='KPUW'   94129     285.747    -235.477  8 10.0 !
! SS90 ='KPVU'   24174     762.617    -899.756  8 10.0 !
! SS91 ='KPWT'   94263    -128.346    -161.636  8 10.0 !
! SS92 ='KRBG'   24231    -185.376    -616.694  8 10.0 !
! SS93 ='KRBL'  725910    -103.127    -950.438  8 10.0 !
! SS94 ='KRDD'   24257    -106.636    -912.642  8 10.0 !
! SS95 ='KRDM'   24230     -11.622    -508.351  8 10.0 !
! SS96 ='KRNT'   94248     -88.400    -160.554  8 10.0 !
! SS97 ='KRXE'     164     710.776    -514.224  8 10.0 !
! SS98 ='KSEA'  727930     -94.509    -165.829  8 10.0 !
! SS99 ='KSFF'   94176     265.111    -137.213  8 10.0 !
! SS100='KSHN'   94227    -156.812    -185.972  8 10.0 !
! SS101='KSKA'   24114     242.353    -141.866  8 10.0 !
! SS102='KSLC'  725720     735.491    -843.200  8 10.0 !
! SS103='KSLE'  726940    -152.136    -436.667  8 10.0 !
! SS104='KSMN'   24196     538.423    -393.145  8 10.0 !
! SS105='KSPB'     175    -137.845    -344.331  8 10.0 !
! SS106='KTCM'  742060    -108.396    -197.813  8 10.0 !
! SS107='KTIW'   94274    -115.450    -185.111  8 10.0 !
! SS108='KTTD'   24242    -106.013    -369.567  8 10.0 !
! SS109='KTWF'   94178     516.133    -679.030  8 10.0 !
! SS110='KUAO'  726959    -133.863    -401.335  8 10.0 !
! SS111='KUIL'  727970    -255.480    -107.220  8 10.0 !
! SS112='KVUO'     186    -123.976    -361.815  8 10.0 !
! SS113='KWMC'  725830     260.408    -865.200  8 10.0 !
! SS114='KYKM'  727810      34.388    -261.319  8 10.0 !
! SS115='KSIY'  725955    -117.790    -774.263  8 10.0 !
-------------------
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Six digit integer for station ID

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 8 -- Upper air meteorological station parameters
--------------


     UPPER AIR STATION VARIABLES
     (One record per station --  NUSTA records in all)

             1      2
         Name     ID      X coord.   Y coord.  Time zone
                            (km)       (km)
        -----------------------------------------------
! US1 ='YZT'    25223   -434.681    198.133    8  ! Port Hardy
```

```
! US2 ='YLW'    94151    112.095    105.490    8  ! Kelowna Apt
! US3 ='MFR'    24225   -148.645   -710.465    8  ! Medford
! US4 ='BOI'    24131    371.767   -572.123    8  ! Boise
! US5 ='SLE'    24232   -153.648   -436.307    8  ! Salem
! US6 ='OTX'     4106    243.587   -136.761    8  ! Spokane Intnl Apt
! US7 ='UIL'    94240   -255.480   -107.220    8  ! Quillayute
! US8 ='TFX'     4102    696.997   -124.670    8  ! Great Falls
! US9 ='LKN'     4105    428.933   -859.514    8  ! Elko
! US10='SLC'    24127    735.212   -842.906    8  ! Salt Lake City
-------------------
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Five digit integer for station ID

!END!


-------------------------------------------------------------------------------

INPUT GROUP: 9 -- Precipitation station parameters
--------------


     PRECIPITATION STATION VARIABLES
     (One record per station --  NPSTA records in all)
     (NOT INCLUDED IF NPSTA = 0)

            1          2
         Name   Station    X coord.  Y coord.
                  Code       (km)      (km)
         ------------------------------------

** 1st line must have "PS1" in (3:5)

! PS1   0001  000001  -333.999  -446.002  !  mm5(I,j): 015083
!PS0002 0002  000002  -321.997  -446.003  !  mm5(I,j): 018083
!PS0003 0003  000003  -309.999  -446.002  !  mm5(I,j): 021083
!PS0004 0004  000004  -298.002  -445.998  !  mm5(I,j): 024083
!PS0005 0005  000005  -286.001  -446.003  !  mm5(I,j): 027083
```

<< *pseudo-stations 6 through 1393 removed for brevity* >>

```
!PS1394 1394  457473  -95.521  -166.410  !
!PS1395 1395  457709  -24.033  -138.289  !
!PS1396 1396  457773  -60.713  -156.463  !
!PS1397 1397  457781  -30.157  -169.233  !
!PS1398 1398  458089  -6.683  -135.739  !

-------------------
```

```
      1
        Four character string for station name
        (MUST START IN COLUMN 9)

      2
        Six digit station code composed of state
        code (first 2 digits) and station ID (last
        4 digits)

!END!
```

Appendix C

Example CALPUFF Input File

```
GHE Unit 3&4, 2003 Met data, 4-km MM5 based winds
24-Hour Max Rates
Gridded & Class I recs, 60 ppb Ozone, 17 ppb NH3
---------------- Run title (3 lines) ------------------------------------------

                    CALPUFF MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

--------------
Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    * METDAT =              *
    or
ISCMET.DAT    input    * ISCDAT =              *
    or
PLMMET.DAT    input    * PLMDAT =              *
    or
PROFILE.DAT   input    * PRFDAT =              *
SURFACE.DAT   input    * SFCDAT =              *
RESTARTB.DAT  input    * RSTARTB=              *
--------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST = ghe.2003.out  !
CONC.DAT      output   ! CONDAT = ghe.2003.con  !
DFLX.DAT      output   * DFDAT  = ghe.2003.dry  *
WFLX.DAT      output   * WFDAT  = ghe.2003.wet  *

VISB.DAT      output   ! VISDAT = ghe.2003.vis  !
TK2D.DAT      output   * T2DDAT =              *
RHO2D.DAT     output   * RHODAT =              *
RESTARTE.DAT  output   * RSTARTE=              *
--------------------------------------------------------------------------------
Emission Files
--------------
PTEMARB.DAT   input    * PTDAT  =              *
VOLEMARB.DAT  input    * VOLDAT =              *
BAEMARB.DAT   input    * ARDAT  =              *
LNEMARB.DAT   input    * LNDAT  =              *
--------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    * OZDAT  =../ozone/o3.03-05.dat *
VD.DAT        input    * VDDAT  =              *
CHEM.DAT      input    * CHEMDAT=              *
H2O2.DAT      input    * H2O2DAT=              *
HILL.DAT      input    * HILDAT=              *
HILLRCT.DAT   input    * RCTDAT=              *
COASTLN.DAT   input    * CSTDAT=              *
FLUXBDY.DAT   input    * BDYDAT=              *
```

```
BCON.DAT      input    * BCNDAT=             *
DEBUG.DAT     output   * DEBUG =             *
MASSFLX.DAT   output   * FLXDAT=             *
MASSBAL.DAT   output   ! BALDAT= ghe.2003.bal !
FOG.DAT       output   * FOGDAT=             *
--------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = T !
         F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length


Provision for multiple input files
----------------------------------

     Number of CALMET.DAT files for run (NMETDAT)
                                    Default: 1       ! NMETDAT =   12  !

     Number of PTEMARB.DAT files for run (NPTDAT)
                                    Default: 0       ! NPTDAT =  0  !

     Number of BAEMARB.DAT files for run (NARDAT)
                                    Default: 0       ! NARDAT =  0  !

     Number of VOLEMARB.DAT files for run (NVOLDAT)
                                    Default: 0       ! NVOLDAT =  0  !

!END!

-------------
Subgroup (0a)
-------------

  The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.01.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.02.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.03.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.04.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.05.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.06.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.07.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.08.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.09.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.10.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.11.met ! !END!
CALMET.DAT    input    ! METDAT =../calmet/calmet.2003.12.met ! !END!

--------------------------------------------------------------------------------
```

```
INPUT GROUP: 1 -- General run control parameters
--------------

    Option to run all periods found
    in the met. file     (METRUN)   Default: 0       ! METRUN =   0  !

         METRUN = 0 - Run period explicitly defined below
         METRUN = 1 - Run all periods in met. file

     Starting date:   Year (IBYR) -- No default       ! IBYR =  2003 !
     (used only if   Month (IBMO) -- No default       ! IBMO =  1   !
      METRUN = 0)      Day (IBDY) -- No default       ! IBDY =  1   !
                      Hour (IBHR) -- No default       ! IBHR =  1   !

     Base time zone        (XBTZ) -- No default       ! XBTZ = 8.0   !
        PST = 8., MST = 7.
        CST = 6., EST = 5.

     Length of run (hours) (IRLG) -- No default       ! IRLG =  8760 !

     Number of chemical species (NSPEC)
                                Default: 5       ! NSPEC =  9   !

     Number of chemical species
     to be emitted  (NSE)           Default: 3       ! NSE =  8   !

     Flag to stop run after
     SETUP phase (ITEST)            Default: 2       ! ITEST =  2   !
     (Used to allow checking
     of the model inputs, files, etc.)
           ITEST = 1 - STOPS program after SETUP phase
           ITEST = 2 - Continues with execution of program
                       after SETUP

     Restart Configuration:

        Control flag (MRESTART)      Default: 0       ! MRESTART =  0   !

           0 = Do not read or write a restart file
           1 = Read a restart file at the beginning of
               the run
           2 = Write a restart file during run
           3 = Read a restart file at beginning of run
               and write a restart file during run

        Number of periods in Restart
        output cycle (NRESPD)        Default: 0       ! NRESPD =  0   !

           0 = File written only at last period
          >0 = File updated every NRESPD periods
```

```
     Meteorological Data Format (METFM)
                                Default: 1       ! METFM =  1   !

           METFM = 1 - CALMET binary file (CALMET.MET)
           METFM = 2 - ISC ASCII file (ISCMET.MET)
           METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
           METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                       surface parameters file (SURFACE.DAT)
           METFM = 5 - AERMET tower file (PROFILE.DAT) and
                       surface parameters file (SURFACE.DAT)

     Meteorological Profile Data Format (MPRFFM)
            (used only for METFM = 1, 2, 3)
                                Default: 1       ! MPRFFM =  1   !

           MPRFFM = 1 - CTDM plus tower file (PROFILE.DAT)
           MPRFFM = 2 - AERMET tower file (PROFILE.DAT)


     PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
     Averaging Time (minutes) (AVET)
                                Default: 60.0    ! AVET = 60. !
     PG Averaging Time (minutes) (PGTIME)
                                Default: 60.0    ! PGTIME = 60. !


!END!


-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


     Vertical distribution used in the
     near field (MGAUSS)              Default: 1     ! MGAUSS =  1   !
        0 = uniform
        1 = Gaussian

     Terrain adjustment method
     (MCTADJ)                         Default: 3     ! MCTADJ =  3   !
        0 = no adjustment
        1 = ISC-type of terrain adjustment
        2 = simple, CALPUFF-type of terrain
            adjustment
        3 = partial plume path adjustment

     Subgrid-scale complex terrain
     flag (MCTSG)                     Default: 0     ! MCTSG =  0   !
        0 = not modeled
        1 = modeled
```

```
Near-field puffs modeled as
elongated 0 (MSLUG)              Default: 0     ! MSLUG =  0   !
   0 = no
   1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS)                         Default: 1     ! MTRANS =  1   !
   0 = no  (i.e., final rise only)
   1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP)       Default: 1     ! MTIP =  1  !
   0 = no  (i.e., no stack tip downwash)
   1 = yes (i.e., use stack tip downwash)

Method used to simulate building
downwash? (MBDW)                 Default: 1     ! MBDW =  1   !
   1 = ISC method
   2 = PRIME method

Vertical wind shear modeled above
stack top? (MSHEAR)              Default: 0     ! MSHEAR =  0  !
   0 = no  (i.e., vertical wind shear not modeled)
   1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT)      Default: 0     ! MSPLIT =  0  !
   0 = no (i.e., puffs not split)
   1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM)       Default: 1     ! MCHEM =  1   !
   0 = chemical transformation not
       modeled
   1 = transformation rates computed
       internally (MESOPUFF II scheme)
   2 = user-specified transformation
       rates used
   3 = transformation rates computed
       internally (RIVAD/ARM3 scheme)
   4 = secondary organic aerosol formation
       computed (MESOPUFF II scheme for OH)

Aqueous phase transformation flag (MAQCHEM)
(Used only if MCHEM = 1, or 3)        Default: 0     ! MAQCHEM =  0   !
   0 = aqueous phase transformation
       not modeled
   1 = transformation rates adjusted
       for aqueous phase reactions

Wet removal modeled ? (MWET)          Default: 1     ! MWET =  1   !
   0 = no
   1 = yes
```

```
Dry deposition modeled ? (MDRY)       Default: 1     ! MDRY =  1   !
   0 = no
   1 = yes
   (dry deposition method specified
    for each species in Input Group 3)

Gravitational settling (plume tilt)
modeled ? (MTILT)                     Default: 0     ! MTILT =  0   !
   0 = no
   1 = yes
   (puff center falls at the gravitational
    settling velocity for 1 particle species)

    Restrictions:
    - MDRY  = 1
    - NSPEC = 1  (must be particle species as well)
    - sg    = 0  GEOMETRIC STANDARD DEVIATION in Group 8 is
                 set to zero for a single particle diameter

Method used to compute dispersion
coefficients (MDISP)                  Default: 3     ! MDISP =  3   !

   1 = dispersion coefficients computed from measured values
       of turbulence, sigma v, sigma w
   2 = dispersion coefficients from internally calculated
       sigma v, sigma w using micrometeorological variables
       (u*, w*, L, etc.)
   3 = PG dispersion coefficients for RURAL areas (computed using
       the ISCST multi-segment approximation) and MP coefficients in
       urban areas
   4 = same as 3 except PG coefficients computed using
       the MESOPUFF II eqns.
   5 = CTDM sigmas used for stable and neutral conditions.
       For unstable conditions, sigmas are computed as in
       MDISP = 3, described above.  MDISP = 5 assumes that
       measured values are read

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5)         Default: 3     ! MTURBVW =  3  !
   1 = use sigma-v or sigma-theta measurements
       from PROFILE.DAT to compute sigma-y
       (valid for METFM = 1, 2, 3, 4, 5)
   2 = use sigma-w measurements
       from PROFILE.DAT to compute sigma-z
       (valid for METFM = 1, 2, 3, 4, 5)
   3 = use both sigma-(v/theta) and sigma-w
       from PROFILE.DAT to compute sigma-y and sigma-z
       (valid for METFM = 1, 2, 3, 4, 5)
   4 = use sigma-theta measurements
       from PLMMET.DAT to compute sigma-y
       (valid only if METFM = 3)
```

```
Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2)                     Default: 3     ! MDISP2 =  3  !
(used only if MDISP = 1 or 5)
   2 = dispersion coefficients from internally calculated
       sigma v, sigma w using micrometeorological variables
       (u*, w*, L, etc.)
   3 = PG dispersion coefficients for RURAL areas (computed using
       the ISCST multi-segment approximation) and MP coefficients in
       urban areas
   4 = same as 3 except PG coefficients computed using
       the MESOPUFF II eqns.

[DIAGNOSTIC FEATURE]
Method used for Lagrangian timescale for Sigma-y
(used only if MDISP=1,2 or MDISP2=1,2)
(MTAULY)                             Default: 0     ! MTAULY =  0   !
   0 = Draxler default 617.284 (s)
   1 = Computed as Lag. Length / (.75 q) -- after SCIPUFF
  10 < Direct user input (s)             -- e.g., 306.9


[DIAGNOSTIC FEATURE]
Method used for Advective-Decay timescale for Turbulence
(used only if MDISP=2 or MDISP2=2)
(MTAUADV)                            Default: 0     ! MTAUADV =  0   !
   0 = No turbulence advection
   1 = Computed (OPTION NOT IMPLEMENTED)
  10 < Direct user input (s)   -- e.g., 800


Method used to compute turbulence sigma-v &
sigma-w using micrometeorological variables
(Used only if MDISP = 2 or MDISP2 = 2)
(MCTURB)                             Default: 1     ! MCTURB =  1   !
   1 = Standard CALPUFF subroutines
   2 = AERMOD subroutines

PG sigma-y,z adj. for roughness?      Default: 0     ! MROUGH =  0  !
(MROUGH)
   0 = no
   1 = yes

Partial plume penetration of          Default: 1     ! MPARTL =  1  !
elevated inversion?
(MPARTL)
   0 = no
   1 = yes

Strength of temperature inversion     Default: 0     ! MTINV =  0  !
provided in PROFILE.DAT extended records?
(MTINV)
```

```
      0 = no (computed from measured/default gradients)
      1 = yes

   PDF used for dispersion under convective conditions?
                                         Default: 0     ! MPDF =  0  !
   (MPDF)
      0 = no
      1 = yes

   Sub-Grid TIBL module used for shore line?
                                         Default: 0     ! MSGTIBL = 0  !
   (MSGTIBL)
      0 = no
      1 = yes

   Boundary conditions (concentration) modeled?
                                         Default: 0     ! MBCON = 0  !
   (MBCON)
      0 = no
      1 = yes, using formatted BCON.DAT file
      2 = yes, using unformatted CONC.DAT file

   Note:  MBCON > 0 requires that the last species modeled
          be 'BCON'.  Mass is placed in species BCON when
          generating boundary condition puffs so that clean
          air entering the modeling domain can be simulated
          in the same way as polluted air.  Specify zero
          emission of species BCON for all regular sources.


   Individual source contributions saved?
                                         Default: 0     ! MSOURCE = 0  !
   (MSOURCE)
      0 = no
      1 = yes


   Analyses of fogging and icing impacts due to emissions from
   arrays of mechanically-forced cooling towers can be performed
   using CALPUFF in conjunction with a cooling tower emissions
   processor (CTEMISS) and its associated postprocessors.  Hourly
   emissions of water vapor and temperature from each cooling tower
   cell are computed for the current cell configuration and ambient
   conditions by CTEMISS. CALPUFF models the dispersion of these
   emissions and provides cloud information in a specialized format
   for further analysis. Output to FOG.DAT is provided in either
   'plume mode' or 'receptor mode' format.

   Configure for FOG Model output?
                                         Default: 0     ! MFOG =  0   !
   (MFOG)
      0 = no
```

```
        1 = yes  - report results in PLUME Mode format
        2 = yes  - report results in RECEPTOR Mode format


     Test options specified to see if
     they conform to regulatory
     values? (MREG)                        Default: 1     ! MREG =  1   !

        0 = NO checks are made
        1 = Technical options must conform to USEPA
            Long Range Transport (LRT) guidance
                       METFM    1 or 2
                       AVET     60. (min)
                       PGTIME   60. (min)
                       MGAUSS   1
                       MCTADJ   3
                       MTRANS   1
                       MTIP     1
                       MCHEM    1 or 3 (if modeling SOx, NOx)
                       MWET     1
                       MDRY     1
                       MDISP    2 or 3
                       MPDF     0 if MDISP=3
                                1 if MDISP=2
                       MROUGH   0
                       MPARTL   1
                       SYTDEP   550. (m)
                       MHFTSZ   0
                       SVMIN    0.5 (m/s)


!END!


-------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

------------
Subgroup (3a)
------------

  The following species are modeled:

! CSPEC =          SO2 !         !END!
! CSPEC =          SO4 !         !END!
! CSPEC =          NOX !         !END!
! CSPEC =         HNO3 !         !END!
! CSPEC =          NO3 !         !END!
! CSPEC =          PMC !         !END!
! CSPEC =          PMF !         !END!
```

```
! CSPEC =          EC !         !END!
! CSPEC =         SOA !         !END!

                                                                  Dry                 OUTPUT GROUP
    SPECIES          MODELED           EMITTED          DEPOSITED                 NUMBER
     NAME         (0=NO, 1=YES)    (0=NO, 1=YES)     (0=NO,                     (0=NONE,
   (Limit: 12                                          1=COMPUTED-GAS          1=1st
CGRUP,
    Characters                                         2=COMPUTED-PARTICLE    2=2nd
CGRUP,
    in length)                                         3=USER-SPECIFIED)      3= etc.)

!          SO2  =         1,                1,            1,                 0  !
!          SO4  =         1,                1,            2,                 0  !
!          NOX  =         1,                1,            1,                 0  !
!         HNO3  =         1,                0,            1,                 0  !
!          NO3  =         1,                1,            2,                 0  !
!          PMC  =         1,                1,            2,                 0  !
!          PMF  =         1,                1,            2,                 0  !
!           EC  =         1,                1,            2,                 0  !
!          SOA  =         1,                1,            2,                 0  !

!END!

  Note:  The last species in (3a) must be 'BCON' when using the
         boundary condition option (MBCON > 0).  Species BCON should
         typically be modeled as inert (no chem transformation or
         removal).


-------------
Subgroup (3b)
-------------
  The following names are used for Species-Groups in which results
  for certain species are combined (added) prior to output.  The
  CGRUP name will be used as the species name in output files.
  Use this feature to model specific particle-size distributions
  by treating each size-range as a separate species.
  Order must be consistent with 3(a) above.



-------------------------------------------------------------------------------


INPUT GROUP: 4 -- Map Projection and Grid control parameters
--------------

     Projection for all (X,Y):
     -------------------------

     Map projection
```

```
(PMAP)                     Default: UTM    ! PMAP = LCC  !

    UTM :  Universal Transverse Mercator
    TTM :  Tangential Transverse Mercator
    LCC :  Lambert Conformal Conic
     PS :  Polar Stereographic
     EM :  Equatorial Mercator
   LAZA :  Lambert Azimuthal Equal Area

False Easting and Northing (km) at the projection origin
(Used only if PMAP= TTM, LCC, or LAZA)
(FEAST)                    Default=0.0     ! FEAST  = 0.000  !
(FNORTH)                   Default=0.0     ! FNORTH = 0.000  !

UTM zone (1 to 60)
(Used only if PMAP=UTM)
(IUTMZN)                   No Default      ! IUTMZN =   0   !

Hemisphere for UTM projection?
(Used only if PMAP=UTM)
(UTMHEM)                   Default: N      ! UTMHEM = N  !
    N   :  Northern hemisphere projection
    S   :  Southern hemisphere projection

Latitude and Longitude (decimal degrees) of projection origin
(Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
(RLAT0)                    No Default      ! RLAT0 = 49.0N  !
(RLON0)                    No Default      ! RLON0 =121.0W  !

    TTM :  RLON0 identifies central (true N/S) meridian of projection
           RLAT0 selected for convenience
    LCC :  RLON0 identifies central (true N/S) meridian of projection
           RLAT0 selected for convenience
    PS  :  RLON0 identifies central (grid N/S) meridian of projection
           RLAT0 selected for convenience
    EM  :  RLON0 identifies central meridian of projection
           RLAT0 is REPLACED by 0.0N (Equator)
    LAZA:  RLON0 identifies longitude of tangent-point of mapping plane
           RLAT0 identifies latitude of tangent-point of mapping plane

Matching parallel(s) of latitude (decimal degrees) for projection
(Used only if PMAP= LCC or PS)
(XLAT1)                    No Default      ! XLAT1 = 30.0N  !
(XLAT2)                    No Default      ! XLAT2 = 60.0N  !

    LCC :  Projection cone slices through Earth's surface at XLAT1 and XLAT2
    PS  :  Projection plane slices through Earth at XLAT1
           (XLAT2 is not used)

----------
Note:  Latitudes and longitudes should be positive, and include a
       letter N,S,E, or W indicating north or south latitude, and
```

```
              east or west longitude.  For example,
              35.9  N Latitude  =  35.9N
              118.7 E Longitude = 118.7E


       Datum-region
       ------------

       The Datum-Region for the coordinates is identified by a character
       string.  Many mapping products currently available use the model of the
       Earth known as the World Geodetic System 1984 (WGS-84).  Other local
       models may be in use, and their selection in CALMET will make its output
       consistent with local mapping products.  The list of Datum-Regions with
       official transformation parameters is provided by the National Imagery and
       Mapping Agency (NIMA).

       NIMA Datum - Regions(Examples)
       ------------------------------------------------------------------------------
       WGS-84    WGS-84 Reference Ellipsoid and Geoid, Global coverage (WGS84)
       NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
       NAR-C     NORTH AMERICAN 1983 GRS 80 Spheroid, MEAN FOR CONUS (NAD83)
       NWS-84    NWS 6370KM Radius, Sphere
       ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

       Datum-region for output coordinates
       (DATUM)                    Default: WGS-84    ! DATUM = NWS-84 !


METEOROLOGICAL Grid:

       Rectangular grid defined for projection PMAP,
       with X the Easting and Y the Northing coordinate

              No. X grid cells (NX)      No default     ! NX =   107 !
              No. Y grid cells (NY)      No default     ! NY =   111 !
           No. vertical layers (NZ)      No default     ! NZ =    10 !

             Grid spacing (DGRIDKM)      No default     ! DGRIDKM =  4. !
                                         Units: km

                  Cell face heights
                      (ZFACE(nz+1))      No defaults
                                         Units: m
              ! ZFACE =0.,20.,40.,65.,120.,200.,400.,700.,1200.,2200.,4000. !

              Reference Coordinates
             of SOUTHWEST corner of
                  grid cell(1, 1):

              X coordinate (XORIGKM)     No default     ! XORIGKM = -344. !
              Y coordinate (YORIGKM)     No default     ! YORIGKM = -444. !
                                        Units: km
```

```
COMPUTATIONAL Grid:

     The computational grid is identical to or a subset of the MET. grid.
     The lower left (LL) corner of the computational grid is at grid point
     (IBCOMP, JBCOMP) of the MET. grid.  The upper right (UR) corner of the
     computational grid is at grid point (IECOMP, JECOMP) of the MET. grid.
     The grid spacing of the computational grid is the same as the MET. grid.

        X index of LL corner (IBCOMP)      No default     ! IBCOMP =  1   !
                  (1 <= IBCOMP <= NX)

        Y index of LL corner (JBCOMP)      No default     ! JBCOMP =  1   !
                  (1 <= JBCOMP <= NY)


        X index of UR corner (IECOMP)      No default     ! IECOMP =  107 !
                  (1 <= IECOMP <= NX)

        Y index of UR corner (JECOMP)      No default     ! JECOMP =  111   !
                  (1 <= JECOMP <= NY)



SAMPLING Grid (GRIDDED RECEPTORS):

     The lower left (LL) corner of the sampling grid is at grid point
     (IBSAMP, JBSAMP) of the MET. grid.  The upper right (UR) corner of the
     sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid.
     The sampling grid must be identical to or a subset of the computational
     grid.  It may be a nested grid inside the computational grid.
     The grid spacing of the sampling grid is DGRIDKM/MESHDN.

        Logical flag indicating if gridded
        receptors are used (LSAMP)         Default: T     ! LSAMP = T !
        (T=yes, F=no)

        X index of LL corner (IBSAMP)      No default     ! IBSAMP =   1   !
         (IBCOMP <= IBSAMP <= IECOMP)

        Y index of LL corner (JBSAMP)      No default     ! JBSAMP =   1   !
         (JBCOMP <= JBSAMP <= JECOMP)


        X index of UR corner (IESAMP)      No default     ! IESAMP =  107  !
         (IBCOMP <= IESAMP <= IECOMP)

        Y index of UR corner (JESAMP)      No default     ! JESAMP =  111  !
         (JBCOMP <= JESAMP <= JECOMP)
```

```
       Nesting factor of the sampling
        grid (MESHDN)                      Default: 1     ! MESHDN =  1  !
        (MESHDN is an integer >= 1)

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 5 -- Output Options
--------------
                                             *                           *
     FILE                        DEFAULT VALUE             VALUE THIS RUN
     ----                        -------------             --------------

   Concentrations (ICON)              1                    !  ICON =  1   !
   Dry Fluxes (IDRY)                  1                    !  IDRY =  0   !
   Wet Fluxes (IWET)                  1                    !  IWET =  0   !
   2D Temperature (IT2D)              0                    !  IT2D =  0   !
   2D Density (IRHO)                  0                    !  IRHO =  0   !
   Relative Humidity (IVIS)           1                    !  IVIS =  1   !
    (RH file is required for
     VISIBILITY analyses)
   Use data compression option in output file?
   (LCOMPRS)                           Default: T          ! LCOMPRS = T !

   *
    0 = Do not create file, 1 = create file



    QA PLOT FILE OUTPUT OPTION:

       Create a standard series of output files (e.g.
       locations of sources, receptors, grids ...)
       suitable for plotting?
       (IQAPLOT)                       Default: 1          ! IQAPLOT =  1  !
         0 = no
         1 = yes


    DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

       Mass flux across specified boundaries
       for selected species reported hourly?
       (IMFLX)                         Default: 0          ! IMFLX =  0  !
         0 = no
         1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
                  are specified in Input Group 0)

       Mass balance for each species
```

```
       reported hourly?
       (IMBAL)                        Default: 0         ! IMBAL =  1  !
         0 = no
         1 = yes (MASSBAL.DAT filename is
              specified in Input Group 0)


    LINE PRINTER OUTPUT OPTIONS:

       Print concentrations (ICPRT)    Default: 0         ! ICPRT =  0   !
       Print dry fluxes (IDPRT)        Default: 0         ! IDPRT =  0   !
       Print wet fluxes (IWPRT)        Default: 0         ! IWPRT =  0   !
       (0 = Do not print, 1 = Print)

       Concentration print interval
       (ICFRQ) in hours                Default: 1         ! ICFRQ =  24   !
       Dry flux print interval
       (IDFRQ) in hours                Default: 1         ! IDFRQ =  1   !
       Wet flux print interval
       (IWFRQ) in hours                Default: 1         ! IWFRQ =  1   !

       Units for Line Printer Output
       (IPRTU)                         Default: 1         ! IPRTU =  1   !
                       for            for
                  Concentration    Deposition
           1 =       g/m**3         g/m**2/s
           2 =      mg/m**3        mg/m**2/s
           3 =      ug/m**3        ug/m**2/s
           4 =      ng/m**3        ng/m**2/s
           5 =     Odour Units

       Messages tracking progress of run
       written to the screen ?
       (IMESG)                         Default: 2         ! IMESG =  2   !
         0 = no
         1 = yes (advection step, puff ID)
         2 = yes (YYYYJJJHH, # old puffs, # emitted puffs)


     SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

                 ---- CONCENTRATIONS ----   ------ DRY FLUXES ------   ------ WET
FLUXES ------   -- MASS FLUX --
   SPECIES
   /GROUP        PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   PRINTED?  SAVED
ON DISK?   SAVED ON DISK?
   -------       ------------------------   ------------------------   ---------------
---------   ---------------
!          SO2 =     0,           1,           0,           0,           0,
0,           0  !
!          NOX =     0,           1,           0,           0,           0,
0,           0  !
```

```
!        HNO3 =     0,           1,           0,           0,           0,
0,          0  !
!         SO4 =     0,           1,           0,           0,           0,
0,          0  !
!         NO3 =     0,           1,           0,           0,           0,
0,          0  !
!         PMC =     0,           1,           0,           0,           0,
0,          0  !
!         PMF =     0,           1,           0,           0,           0,
0,          0  !
!          EC =     0,           1,           0,           0,           0,
0,          0  !
!         SOA =     0,           1,           0,           0,           0,
0,          0  !


  Note:  Species BCON (for MBCON > 0) does not need to be saved on disk.


     OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

       Logical for debug output
       (LDEBUG)                                Default: F     ! LDEBUG = F !

       First puff to track
       (IPFDEB)                                Default: 1     ! IPFDEB =  1  !

       Number of puffs to track
       (NPFDEB)                                Default: 1     ! NPFDEB =  10  !

       Met. period to start output
       (NN1)                                   Default: 1     ! NN1 =  10   !

       Met. period to end output
       (NN2)                                   Default: 10    ! NN2 =  10  !

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
-------------------------

---------------
Subgroup (6a)
---------------
       Number of terrain features (NHILL)      Default: 0     ! NHILL =  0   !

       Number of special complex terrain
       receptors  (NCTREC)                     Default: 0     ! NCTREC =  0   !
```

```
       Terrain and CTSG Receptor data for
       CTSG hills input in CTDM format ?
       (MHILL)                                 No Default     ! MHILL =  2   !
       1 = Hill and Receptor data created
           by CTDM processors & read from
           HILL.DAT and HILLRCT.DAT files
       2 = Hill data created by OPTHILL &
           input below in Subgroup (6b);
           Receptor data in Subgroup (6c)

       Factor to convert horizontal dimensions  Default: 1.0   ! XHILL2M = 0. !
       to meters (MHILL=1)

       Factor to convert vertical dimensions    Default: 1.0   ! ZHILL2M = 0. !
       to meters (MHILL=1)

       X-origin of CTDM system relative to      No Default     ! XCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)

       Y-origin of CTDM system relative to      No Default     ! YCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)

! END !

---------------
Subgroup (6b)
---------------

                      1 **
     HILL information


HILL           XC         YC        THETAH  ZGRID  RELIEF    EXPO 1    EXPO 2   SCALE 1
SCALE 2    AMAX1     AMAX2
 NO.          (km)       (km)       (deg.)   (m)      (m)      (m)       (m)       (m)
(m)       (m)       (m)
----          ----       ----       ------  -----  ------    ------    ------   -------
-------    -----     -----

---------------
Subgroup (6c)
---------------

    COMPLEX TERRAIN RECEPTOR INFORMATION

                      XRCT         YRCT        ZRCT          XHH
                      (km)         (km)         (m)
                     ------        -----      ------         ----


-------------------
```

```
1
     Description of Complex Terrain Variables:
          XC, YC  = Coordinates of center of hill
          THETAH  = Orientation of major axis of hill (clockwise from
                    North)
          ZGRID   = Height of the  0  of the grid above mean sea
                    level
          RELIEF  = Height of the crest of the hill above the grid elevation
          EXPO 1  = Hill-shape exponent for the major axis
          EXPO 2  = Hill-shape exponent for the major axis
          SCALE 1 = Horizontal length scale along the major axis
          SCALE 2 = Horizontal length scale along the minor axis
          AMAX    = Maximum allowed axis length for the major axis
          BMAX    = Maximum allowed axis length for the major axis

          XRCT, YRCT = Coordinates of the complex terrain receptors
          ZRCT    = Height of the ground (MSL) at the complex terrain
                    Receptor
          XHH     = Hill number associated with each complex terrain receptor
                    (NOTE: MUST BE ENTERED AS A REAL NUMBER)

   **
     NOTE: DATA for each hill and CTSG receptor are treated as a separate
           input subgroup and therefore must end with an input group terminator.

-------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

      SPECIES     DIFFUSIVITY      ALPHA STAR      REACTIVITY    MESOPHYLL RESISTANCE
HENRY'S LAW COEFFICIENT
       NAME        (cm**2/s)                                            (s/cm)
(dimensionless)
      -------     -----------      ----------      ----------    --------------------
-----------------------

!          SO2 =     0.1509,         1000.,           8.,            0.,     0.04 !
!          NOX =     0.1656,            1.,           8.,            5.,      3.5 !
!         HNO3 =     0.1628,            1.,          18.,            0.,   0.00000008
!

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------
```

```
     For SINGLE SPECIES, the mean and standard deviation are used to
     compute a deposition velocity for NINT (see group 9) size-ranges,
     and these are then averaged to obtain a mean deposition velocity.

     For GROUPED SPECIES, the size distribution should be explicitly
     specified (by the 'species' in the group), and the standard deviation
     for each should be entered as 0.  The model will then use the
     deposition velocity for the stated mean diameter.

      SPECIES      GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
       NAME             DIAMETER                   DEVIATION
                        (microns)                  (microns)
      -------      -------------------        ------------------
!          SO4 =         0.48,                     2.0  !
!          NO3 =         0.48,                     2.0  !
!          SOA =         0.48,                     2.0  !
!          PMF =         0.48,                     2.0  !
!          PMC =          5.0,                     1.5  !
!           EC =         0.48,                     2.0  !

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
--------------

     Reference cuticle resistance (s/cm)
     (RCUTR)                          Default: 30    !  RCUTR = 30.0 !
     Reference ground resistance  (s/cm)
     (RGR)                            Default: 10    !    RGR = 10.0 !
     Reference pollutant reactivity
     (REACTR)                         Default: 8     ! REACTR = 8.0 !

     Number of particle-size intervals used to
     evaluate effective particle deposition velocity
     (NINT)                           Default: 9     !   NINT =  9   !

     Vegetation state in unirrigated areas
     (IVEG)                           Default: 1     !   IVEG =  1    !
        IVEG=1 for active and unstressed vegetation
        IVEG=2 for active and stressed vegetation
        IVEG=3 for inactive vegetation

!END!


-------------------------------------------------------------------------------
```

```
INPUT GROUP: 10 -- Wet Deposition Parameters
---------------


                      Scavenging Coefficient -- Units: (sec)**(-1)

       Pollutant      Liquid Precip.       Frozen Precip.
       ---------      --------------       --------------
!          SO2 =         3.0E-05,             0.0E00 !
!          SO4 =         1.0E-04,            3.0E-05 !
!          NOX =          0.0E00,             0.0E00 !
!         HNO3 =         6.0E-05,             0.0E00 !
!          NO3 =         1.0E-04,            3.0E-05 !
!          PMC =         1.0E-04,            3.0E-05 !
!          PMF =         1.0E-04,            3.0E-05 !
!           EC =         1.0E-04,            3.0E-05 !
!          SOA =         1.0E-04,            3.0E-05 !

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 11 -- Chemistry Parameters
---------------

     Ozone data input option (MOZ)     Default: 1            ! MOZ =  0  !
     (Used only if MCHEM = 1, 3, or 4)
        0 = use a monthly background ozone value
        1 = read hourly ozone concentrations from
            the OZONE.DAT data file

     Monthly ozone concentrations
     (Used only if MCHEM = 1, 3, or 4 and
      MOZ = 0 or MOZ = 1 and all hourly O3 data missing)
     (BCKO3) in ppb                    Default: 12*80.
     !  BCKO3 = 12*60. !

     Monthly ammonia concentrations
     (Used only if MCHEM = 1, or 3)
     (BCKNH3) in ppb                   Default: 12*10.
     !  BCKNH3 = 12*17.0 !

     Nighttime SO2 loss rate (RNITE1)
     in percent/hour                   Default: 0.2          ! RNITE1 = .2 !

     Nighttime NOx loss rate (RNITE2)
     in percent/hour                   Default: 2.0          ! RNITE2 = 2.0 !

     Nighttime HNO3 formation rate (RNITE3)
     in percent/hour                   Default: 2.0          ! RNITE3 = 2.0 !
```

```
    H2O2 data input option (MH2O2)    Default: 1           ! MH2O2 =  1   !
    (Used only if MAQCHEM = 1)
       0 = use a monthly background H2O2 value
       1 = read hourly H2O2 concentrations from
           the H2O2.DAT data file

    Monthly H2O2 concentrations
    (Used only if MQACHEM = 1 and
     MH2O2 = 0 or MH2O2 = 1 and all hourly H2O2 data missing)
    (BCKH2O2) in ppb                  Default: 12*1.
    !  BCKH2O2 = 12*1.0 !


--- Data for SECONDARY ORGANIC AEROSOL (SOA) Option
    (used only if MCHEM = 4)

    The SOA module uses monthly values of:
         Fine particulate concentration in ug/m^3 (BCKPMF)
         Organic fraction of fine particulate     (OFRAC)
         VOC / NOX ratio (after reaction)         (VCNX)
    to characterize the air mass when computing
    the formation of SOA from VOC emissions.
    Typical values for several distinct air mass types are:

       Month    1    2    3    4    5    6    7    8    9   10   11   12
               Jan  Feb  Mar  Apr  May  Jun  Jul  Aug  Sep  Oct  Nov  Dec

    Clean Continental
       BCKPMF   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.
       OFRAC  .15  .15  .20  .20  .20  .20  .20  .20  .20  .20  .20  .15
       VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

    Clean Marine (surface)
       BCKPMF  .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5
       OFRAC  .25  .25  .30  .30  .30  .30  .30  .30  .30  .30  .30  .25
       VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

    Urban - low biogenic (controls present)
       BCKPMF  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.
       OFRAC  .20  .20  .25  .25  .25  .25  .25  .25  .20  .20  .20  .20
       VCNX     4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.

    Urban - high biogenic (controls present)
       BCKPMF  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.
       OFRAC  .25  .25  .30  .30  .30  .55  .55  .55  .35  .35  .35  .25
       VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

    Regional Plume
       BCKPMF  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.
       OFRAC  .20  .20  .25  .35  .25  .40  .40  .40  .30  .30  .30  .20
       VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.
```

```
     Urban - no controls present
        BCKPMF 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100.
        OFRAC  .30  .30  .35  .35  .35  .55  .55  .55  .35  .35  .35  .30
        VCNX     2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.

     Default: Clean Continental
     !  BCKPMF = 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00,
1.00 !
     !  OFRAC  = 0.15, 0.15, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20,
0.15 !
     !  VCNX   = 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00,
50.00, 50.00 !


!END!


-------------------------------------------------------------------------------


INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---------------

     Horizontal size of puff (m) beyond which
     time-dependent dispersion equations (Heffter)
     are used to determine sigma-y and
     sigma-z (SYTDEP)                           Default: 550.   ! SYTDEP = 5.5E02 !

     Switch for using Heffter equation for sigma z
     as above (0 = Not use Heffter; 1 = use Heffter
     (MHFTSZ)                                   Default: 0      ! MHFTSZ =  0   !

     Stability class used to determine plume
     growth rates for puffs above the boundary
     layer (JSUP)                               Default: 5      ! JSUP =  5   !

     Vertical dispersion constant for stable
     conditions (k1 in Eqn. 2.7-3)  (CONK1)     Default: 0.01   ! CONK1 = .01 !

     Vertical dispersion constant for neutral/
     unstable conditions (k2 in Eqn. 2.7-4)
     (CONK2)                                    Default: 0.1    ! CONK2 = .1 !

     Factor for determining Transition-point from
     Schulman-Scire to Huber-Snyder Building Downwash
     scheme (SS used for Hs < Hb + TBD * HL)
     (TBD)                                      Default: 0.5    ! TBD = .5 !
        TBD < 0   ==> always use Huber-Snyder
        TBD = 1.5 ==> always use Schulman-Scire
        TBD = 0.5 ==> ISC Transition-point
```

```
Range of land use categories for which
urban dispersion is assumed
(IURB1, IURB2)                           Default: 10     ! IURB1 =  10  !
                                                  19     ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4,5)

   Land use category for modeling domain
   (ILANDUIN)                            Default: 20     ! ILANDUIN =  20  !

   Roughness length (m) for modeling domain
   (Z0IN)                                Default: 0.25   ! Z0IN = .25 !

   Leaf area index for modeling domain
   (XLAIIN)                              Default: 3.0    ! XLAIIN = 3.0 !

   Elevation above sea level (m)
   (ELEVIN)                              Default: 0.0    ! ELEVIN = .0 !

   Latitude (degrees) for met location
   (XLATIN)                              Default: -999.  ! XLATIN = -999.0 !

   Longitude (degrees) for met location
   (XLONIN)                              Default: -999.  ! XLONIN = -999.0 !

Specialized information for interpreting single-point Met data files -----

   Anemometer height (m) (Used only if METFM = 2,3)
   (ANEMHT)                              Default: 10.    ! ANEMHT = 10.0 !

   Form of lateral turbulance data in PROFILE.DAT file
   (Used only if METFM = 4,5 or MTURBVW = 1 or 3)
   (ISIGMAV)                             Default: 1      ! ISIGMAV =  1  !
       0 = read sigma-theta
       1 = read sigma-v

   Choice of mixing heights (Used only if METFM = 4)
   (IMIXCTDM)                            Default: 0      ! IMIXCTDM =  0  !
       0 = read PREDICTED mixing heights
       1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN)                                 Default: 1.0    ! XMXLEN = 1.0 !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN)                                Default: 1.0    ! XSAMLEN = 1.0 !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW)                                  Default: 99     ! MXNEW =  99   !
```

```
     Maximum Number of sampling steps for
     one puff/slug during one time step
     (MXSAM)                                   Default: 99      ! MXSAM =  99  !

     Number of iterations used when computing
     the transport wind for a sampling step
     that includes gradual rise (for CALMET
     and PROFILE winds)
     (NCOUNT)                                  Default: 2       ! NCOUNT =  2   !

     Minimum sigma y for a new puff/slug (m)
     (SYMIN)                                   Default: 1.0     ! SYMIN = 1.0  !

     Minimum sigma z for a new puff/slug (m)
     (SZMIN)                                   Default: 1.0     ! SZMIN = 1.0  !

     Default minimum turbulence velocities sigma-v and sigma-w
     for each stability class over land and over water (m/s)
     (SVMIN(12) and SWMIN(12))

                     ----------  LAND  ----------       ---------  WATER  ----------
        Stab Class :  A    B    C    D    E    F         A    B    C    D    E    F
                     ---  ---  ---  ---  ---  ---       ---  ---  ---  ---  ---  ---
     Default SVMIN : .50, .50, .50, .50, .50, .50,      .37, .37, .37, .37, .37, .37
     Default SWMIN : .20, .12, .08, .06, .03, .016,     .20, .12, .08, .06, .03, .016

           * SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500,  0.370, 0.370, 0.370,
0.370, 0.370, 0.370*
           ! SVMIN = 12* 0.5 ! mreg =1 requirement

           ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016,  0.200, 0.120, 0.080,
0.060, 0.030, 0.016!

     Divergence criterion for dw/dz across puff
     used to initiate adjustment for horizontal
     convergence (1/s)
     Partial adjustment starts at CDIV(1), and
     full adjustment is reached at CDIV(2)
     (CDIV(2))                                 Default: 0.0,0.0  ! CDIV = 0.0, 0.0 !

     Minimum wind speed (m/s) allowed for
     non-calm conditions. Also used as minimum
     speed returned when using power-law
     extrapolation toward surface
     (WSCALM)                                  Default: 0.5     ! WSCALM = .5 !

     Maximum mixing height (m)
     (XMAXZI)                                  Default: 3000.   ! XMAXZI = 3000.0 !

     Minimum mixing height (m)
     (XMINZI)                                  Default: 50.     ! XMINZI = 50.0 !
```

```
Default wind speed classes --
5 upper bounds (m/s) are entered;
the 6th class has no upper limit
(WSCAT(5))                      Default   :
                                ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10.8 (10.8+)

                         Wind Speed Class :  1     2     3     4     5
                                            ---   ---   ---   ---   ---
                                  ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

Default wind speed profile power-law
exponents for stabilities 1-6
(PLX0(6))                       Default   : ISC RURAL values
                                ISC RURAL : .07, .07, .10, .15, .35, .55
                                ISC URBAN : .15, .15, .20, .25, .30, .30

                          Stability Class :  A     B     C     D     E     F
                                            ---   ---   ---   ---   ---   ---
                                   ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !

Default potential temperature gradient
for stable classes E, F (degK/m)
(PTG0(2))                       Default: 0.020, 0.035
                                   ! PTG0 = 0.020,   0.035 !

Default plume path coefficients for
each stability class (used when option
for partial plume height terrain adjustment
is selected -- MCTADJ=3)
(PPC(6))                  Stability Class :  A     B     C     D     E     F
                             Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
                                            ---   ---   ---   ---   ---   ---
                                   !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

Slug-to-puff transition criterion factor
equal to sigma-y/length of slug
(SL2PF)                               Default: 10.        ! SL2PF = 10.0!

Puff-splitting control variables ------------------------

  VERTICAL SPLIT
  --------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)                            Default:   3        ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
```

```
  24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
  0=do not re-split    1=eligible for re-split
  (IRESPLIT(24))                      Default:  Hour 17 = 1
  !  IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

  Split is allowed only if last hour's mixing
  height (m) exceeds a minimum value
  (ZISPLIT)                           Default: 100.       ! ZISPLIT = 100.0 !

  Split is allowed only if ratio of last hour's
  mixing ht to the maximum mixing ht experienced
  by the puff is less than a maximum value (this
  postpones a split until a nocturnal layer develops)
  (ROLDMAX)                           Default: 0.25       ! ROLDMAX = 0.25 !


  HORIZONTAL SPLIT
  ----------------

  Number of puffs that result every time a puff
  is split - nsplith=5 means that 1 puff splits
  into 5
  (NSPLITH)                           Default:   5        ! NSPLITH =  5  !

  Minimum sigma-y (Grid Cells Units) of puff
  before it may be split
  (SYSPLITH)                          Default:  1.0       ! SYSPLITH = 1.0 !

  Minimum puff elongation rate (SYSPLITH/hr) due to
  wind shear, before it may be split
  (SHSPLITH)                          Default:  2.        ! SHSPLITH = 2.0 !

  Minimum concentration (g/m^3) of each
  species in puff before it may be split
  Enter array of NSPEC values; if a single value is
  entered, it will be used for ALL species
  (CNSPLITH)                          Default:  1.0E-07   ! CNSPLITH = 1.0E-07 !

Integration control variables ------------------------

  Fractional convergence criterion for numerical SLUG
  sampling integration
  (EPSSLUG)                           Default:   1.0e-04  ! EPSSLUG = 1.0E-04 !

  Fractional convergence criterion for numerical AREA
  source integration
  (EPSAREA)                           Default:   1.0e-06  ! EPSAREA = 1.0E-06 !

  Trajectory step-length (m) used for numerical rise
  integration
  (DSRISE)                            Default:   1.0      ! DSRISE = 1.0 !
```

```
     Boundary Condition (BC) Puff control variables ------------------------

       Minimum height (m) to which BC puffs are mixed as they are emitted
       (MBCON=2 ONLY).  Actual height is reset to the current mixing height
       at the release point if greater than this minimum.
       (HTMINBC)                            Default:   500.     ! HTMINBC = 500. !

       Search radius (km) about a receptor for sampling nearest BC puff.
       BC puffs are typically emitted with a spacing of one grid cell
       length, so the search radius should be greater than DGRIDKM.
       (RSAMPBC)                            Default:   10.      ! RSAMPBC = 10 !

       Near-Surface depletion adjustment to concentration profile used when
       sampling BC puffs?
       (MDEPBC)                             Default:   1        ! MDEPBC = 1  !
          0 = Concentration is NOT adjusted for depletion
          1 = Adjust Concentration for depletion

!END!


-------------------------------------------------------------------------------


INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters
--------------------------------

---------------
Subgroup (13a)
---------------

     Number of point sources with
     parameters provided below      (NPT1)  No default  !  NPT1 =  6 !

     Units used for point source
     emissions below                (IPTU)  Default: 1  !  IPTU =   3 !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (13d)        (NSPT1) Default: 0  !  NSPT1 =  0  !

     Number of point sources with
     variable emission parameters
     provided in external file      (NPT2)  No default  !  NPT2 =  0  !
```

```
     (If NPT2 > 0, these point
     source emissions are read from
     the file: PTEMARB.DAT)

!END!

---------------
Subgroup (13b)
---------------
                                      a
          POINT SOURCE: CONSTANT DATA
          -----------------------------
                                                                              b
c
  Source       X UTM      Y UTM      Stack    Base     Stack    Exit  Exit    Bldg.
Emission
   No.     Coordinate Coordinate Height Elevation Diameter  Vel.  Temp.   Dwash
Rates
              (km)      (km)       (m)      (m)       (m)  (m/s) (deg. K)
  ------   ---------- ---------- ------  ------   -------- ----- -------- ----- ------
--
** emiss updated 3/5/2009
**                                                                    so2    so4    nox
hno3  no3  pmc     pmf     ec soa/oc
   ! SRCNAM = ctg3  !
   ! X =  -181.612, -215.428, 54.9, 74.5, 5.49, 20.2, 344.7, 0.0, 4.854, 3.640,
20.008,0.0, 0.000, 0.0, 0.000, 4.750, 9.245!!END!
   ! SRCNAM = ctg4  !
   ! X =  -181.571, -215.431, 54.9, 74.5, 5.49, 20.2, 344.7, 0.0, 4.854, 3.640,
20.008,0.0, 0.000, 0.0, 0.000, 4.750, 9.245!!END!
   ! SRCNAM = auxb2 !
   ! X =  -181.516, -215.443, 14.9, 74.6, 0.54, 20.8, 476.5, 0.0, 0.179, 0.021, 0.322,
0.0,0.0006, 0.0, 0.028, 0.000, 0.088!!END!
   ! SRCNAM = dg2   !
   ! X =  -181.542, -215.431,  4.0, 74.5, 0.15, 94.6, 760.9, 0.0, 0.000, 0.000, 0.164,
0.0, 0.000, 0.0, 0.000, 0.006, 0.002!!END!
   ! SRCNAM = fpmp2 !
   ! X =  -181.610, -215.406,  4.0, 74.3, 0.13, 72.7, 828.7, 0.0, 0.000, 0.000, 0.057,
0.0, 0.000, 0.0, 0.000, 0.006, 0.002!!END!
   ! SRCNAM = cool  !
   ! X =  -181.549, -215.376, 15.8, 74.0, 12.98, 5.4, 312.0, 0.0, 0.000, 0.000, 0.000,
0.0, 0.000, 0.0, 0.788, 0.000, 0.000!!END!

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

     SRCNAM  is a 12-character name for a source
             (No default)
```

```
     X       is an array holding the source data listed by the column headings
             (No default)
     SIGYZI  is an array holding the initial sigma-y and sigma-z (m)
             (Default: 0.,0.)
     FMFAC   is a vertical momentum flux factor (0. or 1.0) used to represent
             the effect of rain-caps or other physical configurations that
             reduce momentum rise associated with the actual exit velocity.
             (Default: 1.0  -- full momentum used)
     ZPLTFM  is the platform height (m) for sources influenced by an isolated
             structure that has a significant open area between the surface
             and the bulk of the structure, such as an offshore oil platform.
             The Base Elevation is that of the surface (ground or ocean),
             and the Stack Height is the release height above the Base (not
             above the platform).  Building heights entered in Subgroup 13c
             must be those of the buildings on the platform, measured from
             the platform deck.  ZPLTFM is used only with MBDW=1 (ISC
             downwash method) for sources with building downwash.
             (Default: 0.0)

    b
     0. = No building downwash modeled
     1. = Downwash modeled for buildings resting on the surface
     2. = Downwash modeled for buildings raised above the surface (ZPLTFM > 0.)
     NOTE: must be entered as a REAL number (i.e., with decimal point)

    c
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IPTU
     (e.g. 1 for g/s).

---------------
Subgroup (13c)
---------------

           BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH
           -------------------------------------------------------
Source                                                                    a
 No.       Effective building height, width, length and X/Y offset (in meters)
           every 10 degrees.  LENGTH, XBADJ, and YBADJ are only needed for
           MBDW=2 (PRIME downwash option)
------     --------------------------------------------------------------------


--------

    a
     Building height, width, length, and X/Y offset from the source are treated
     as a separate input subgroup for each source and therefore must end with
     an input group terminator.

---------------
```

```
Subgroup (13d)
---------------
                                                  a
          POINT SOURCE: VARIABLE EMISSIONS DATA
          ---------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 13b.  Factors entered multiply the rates in 13b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)



--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------


INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters
--------------------------------


---------------
Subgroup (14a)
---------------

     Number of polygon area sources with
     parameters specified below (NAR1)       No default  !  NAR1 =  0   !

     Units used for area source
     emissions below            (IARU)       Default: 1  !  IARU =   1  !
           1 =        g/m**2/s
           2 =       kg/m**2/hr
```

```
          3 =       lb/m**2/hr
          4 =     tons/m**2/yr
          5 =     Odour Unit * m/s  (vol. flux/m**2 of odour compound)
          6 =     Odour Unit * m/min
          7 =     metric tons/m**2/yr

    Number of source-species
    combinations with variable
    emissions scaling factors
    provided below in (14d)        (NSAR1) Default: 0  !  NSAR1 =  0  !

    Number of buoyant polygon area sources
    with variable location and emission
    parameters (NAR2)                      No default  !  NAR2 =  0   !
    (If NAR2 > 0, ALL parameter data for
    these sources are read from the file: BAEMARB.DAT)

!END!

---------------
Subgroup (14b)
---------------
                                     a
          AREA SOURCE: CONSTANT DATA
          ----------------------------
                                                         b
Source           Effect.    Base      Initial    Emission
 No.             Height   Elevation   Sigma z     Rates
                   (m)       (m)        (m)
-------          ------    ------     --------   ---------



--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.
    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IARU
     (e.g. 1 for g/m**2/s).

---------------
Subgroup (14c)
---------------

           COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON
           --------------------------------------------------------
Source                                                             a
 No.       Ordered list of X followed by list of Y, grouped by source
------     ------------------------------------------------------------
```

```
--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.


---------------
Subgroup (14d)
---------------
                                               a
          AREA SOURCE: VARIABLE EMISSIONS DATA
          --------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 14b.  Factors entered multiply the rates in 14b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)



--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


------------------------------------------------------------------------------

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters
---------------------------

---------------
Subgroup (15a)
---------------
```

```
     Number of buoyant line sources
     with variable location and emission
     parameters (NLN2)                            No default  !  NLN2 =  0   !

     (If NLN2 > 0, ALL parameter data for
      these sources are read from the file: LNEMARB.DAT)

     Number of buoyant line sources (NLINES)       No default   ! NLINES =  0  !

     Units used for line source
     emissions below                (ILNU)         Default: 1  !  ILNU =   1  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (15c)        (NSLN1) Default: 0  !  NSLN1 =  0  !

     Maximum number of segments used to model
     each line (MXNSEG)                            Default: 7   ! MXNSEG =  7  !

     The following variables are required only if NLINES > 0.  They are
     used in the buoyant line source plume rise calculations.

        Number of distances at which               Default: 6   ! NLRISE =  6  !
        transitional rise is computed

        Average building length (XL)               No default   ! XL = .0 !
                                                   (in meters)

        Average building height (HBL)              No default   ! HBL = .0 !
                                                   (in meters)

        Average building width (WBL)               No default   ! WBL = .0 !
                                                   (in meters)

        Average line source width (WML)            No default   ! WML = .0 !
                                                   (in meters)

        Average separation between buildings (DXL) No default   ! DXL = .0 !
                                                   (in meters)

        Average buoyancy parameter (FPRIMEL)       No default   ! FPRIMEL = .0 !
                                                   (in m**4/s**3)

!END!
```

```
---------------
Subgroup (15b)
---------------

          BUOYANT LINE SOURCE: CONSTANT DATA
          ----------------------------------

a
Source     Beg. X      Beg. Y      End. X    End. Y     Release    Base
Emission
 No.     Coordinate  Coordinate  Coordinate Coordinate  Height    Elevation      Rates
            (km)        (km)        (km)       (km)       (m)        (m)
------   ----------  ----------  ---------  ----------  -------   ---------    -------
--

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by ILNTU
     (e.g. 1 for g/s).

---------------
Subgroup (15c)
---------------
                                                               a
          BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA
          ----------------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 15b.  Factors entered multiply the rates in 15b.
     Skip sources here that have constant emissions.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                               Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
```

```
                                        0, 5, 10, 15, 20, 25, 30, 35, 40,
                                        45, 50, 50+)



--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------


INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters
---------------------------

---------------
Subgroup (16a)
---------------

     Number of volume sources with
     parameters provided in 16b,c (NVL1)     No default  !  NVL1 =  0   !

     Units used for volume source
     emissions below in 16b       (IVLU)     Default: 1  !  IVLU =   1  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

     Number of volume sources with
     variable location and emission
     parameters                   (NVL2)     No default  !  NVL2 =   0   !

     (If NVL2 > 0, ALL parameter data for
      these sources are read from the VOLEMARB.DAT file(s) )

!END!

---------------
Subgroup (16b)
---------------
                                           a
```

```
         VOLUME SOURCE: CONSTANT DATA
         ------------------------------
                                                                                    b
      X UTM       Y UTM      Effect.    Base     Initial    Initial    Emission
   Coordinate  Coordinate   Height   Elevation  Sigma y    Sigma z     Rates
      (km)        (km)        (m)       (m)        (m)       (m)
   ----------  ----------   ------    ------    --------   --------   --------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IVLU
     (e.g. 1 for g/s).

---------------
Subgroup (16c)
---------------
                                                 a
          VOLUME SOURCE: VARIABLE EMISSIONS DATA
          ---------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 16b.  Factors entered multiply the rates in 16b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use VOLEMARB.DAT and NVL2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)



--------
    a
```

```
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
-----------------------

---------------
Subgroup (17a)
---------------

     Number of non-gridded receptors (NREC)  No default  !  NREC =  3541 !

!END!

---------------
Subgroup (17b)
---------------
                                               a
           NON-GRIDDED (DISCRETE) RECEPTOR DATA
           ------------------------------------

                  X UTM       Y UTM        Ground       Height   b
Receptor       Coordinate   Coordinate    Elevation   Above Ground
  No.             (km)        (km)          (m)           (m)
--------       ----------   ----------    ---------   ------------
** alla
1  ! x = -24.542, -173.238, 1477.0 ! !END!
2  ! x = -23.330, -173.243, 1463.0 ! !END!
3  ! x = -25.746, -171.442, 1478.0 ! !END!
4  ! x = -24.535, -171.447, 1604.0 ! !END!
5  ! x = -23.323, -171.452, 1183.0 ! !END!
```

<< *removed receptors 6 through 3536 for brevity* >>

```
3537  ! x = -30.266, -346.802, 382.0 ! !END!
3538  ! x = -29.018, -346.809, 593.0 ! !END!
3539  ! x = -27.770, -346.814, 430.0 ! !END!
3540  ! x = -27.762, -345.025, 505.0 ! !END!
3541  ! x = -26.506, -343.242, 667.0 ! !END!

-------------
    a
     Data for each receptor are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     Receptor height above ground is optional.  If no value is entered,
     the receptor is placed on the ground.
```

Appendix D

Example CALPOST Input File

```
GHE Unit 3&4 Class I Analysis 2003 Visibility Analysis
alla Recs
Visibility Method 2
---------------- Run title (3 lines) ------------------------------------------

                    CALPOST MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names
--------------

Input Files
-----------

File                      Default File Name
----                      -----------------
Conc/Dep Flux File        MODEL.DAT          ! MODDAT =../ghe.2003.con   !
Relative Humidity File    VISB.DAT           ! VISDAT =../ghe.2003.vis   !
Background Data File      BACK.DAT           * BACKDAT =   *
Transmissometer or        VSRN.DAT           * VSRDAT =   *
Nephelometer Data File     or
DATSAV Weather Data File   or
Prognostic Weather  File

Output Files
------------

File                      Default File Name
----                      -----------------
List File                 CALPOST.LST        ! PSTLST =vis.alla.2003.mth2.lst   !

Pathname for Timeseries Files   (blank)      * TSPATH =   *
(activate with exclamation points only if
providing NON-BLANK character string)

Pathname for Plot Files   (blank)            * PLPATH =   *
(activate with exclamation points only if
 providing NON-BLANK character string)

User Character String (U) to augment default filenames
(activate with exclamation points only if
 providing NON-BLANK character string)

Timeseries          TSERIES_ASPEC_ttHR_CONC_TSUNAM.DAT
Peak Value          PEAKVAL_ASPEC_ttHR_CONC_TSUNAM.DAT

                                             * TSUNAM =   *

Top Nth Rank Plot   RANK(ALL)_ASPEC_ttHR_CONC_TUNAM.DAT
                or  RANK(ii)_ASPEC_ttHR_CONC_TUNAM.GRD
```

```
                                                   * TUNAM = *

Exceedance Plot      EXCEED_ASPEC_ttHR_CONC_XUNAM.DAT
                 or  EXCEED_ASPEC_ttHR_CONC_XUNAM.GRD

                                                   * XUNAM =   *

Echo Plot
(Specific Days)
           yyyy_Mmm_Ddd_hhmm(UTCszzzz)_L00_ASPEC_ttHR_CONC.DAT
     or    yyyy_Mmm_Ddd_hhmm(UTCszzzz)_L00_ASPEC_ttHR_CONC.GRD


Visibility Plot      DAILY_VISIB_VUNAM.DAT   ! VUNAM =alla03m2 !
(Daily Peak Summary)


Auxiliary Output Files
----------------------

File                      Default File Name
----                      -----------------
Visibility Change         DELVIS.DAT         ! DVISDAT =delv_alla.2003.mth2.dat !

--------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case               ! LCFILES = T !
         F = UPPER CASE
NOTE: (1) file/path names can be up to 132 characters in length
NOTE: (2) Filenames for ALL PLOT and TIMESERIES FILES are constructed
          using a template that includes a pathname, user-supplied
          character(s), and context-specific strings, where
             ASPEC = Species Name
              CONC = CONC Or WFLX Or DFLX Or TFLX
                tt = Averaging Period (e.g. 03)
                ii = Rank (e.g. 02)
                hh = Hour(ending) in LST
             szzzz = LST time zone shift (EST is -0500)
              yyyy = Year(LST)
                mm = Month(LST)
                dd = day of month (LST)
          are determined internally based on selections made below.
          If a path or user-supplied character(s) are supplied, each
          must contain at least 1 non-blank character.

!END!
--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------
```

```
     Option to run all periods found
     in the met. file(s)  (METRUN)        Default: 0   ! METRUN =   0  !

         METRUN = 0 - Run period explicitly defined below
         METRUN = 1 - Run all periods in CALPUFF data file(s)

     Starting date:    Year   (ISYR)  --    No default   ! ISYR  =  2003 !
                       Month  (ISMO)  --    No default   ! ISMO  =  1  !
                       Day    (ISDY)  --    No default   ! ISDY  =  1  !
     Starting time:    Hour   (ISHR)  --    No default   ! ISHR  =  1  !

     Number of hours to process (NHRS) -- No default   ! NHRS  =  8760  !

     (These are only used if METRUN = 0)

     Process every period of data?
                                (NREP) -- Default: 1   ! NREP  =  1  !
      (1 = every period processed,
       2 = every 2nd period processed,
       5 = every 5th period processed, etc.)

Species & Concentration/Deposition Information
----------------------------------------------

      Species to process (ASPEC)       -- No default   ! ASPEC = VISIB  !
      (ASPEC = VISIB for visibility processing)

      Layer/deposition code (ILAYER)   -- Default: 1   ! ILAYER =  1  !
        '1'  for CALPUFF concentrations,
        '-1' for dry deposition fluxes,
        '-2' for wet deposition fluxes,
        '-3' for wet+dry deposition fluxes.

      Scaling factors of the form:     -- Defaults:    ! A =  0.0    !
            X(new) = X(old) * A + B         A = 0.0    ! B =  0.0    !
        (NOT applied if A = B = 0.0)        B = 0.0

      Add Hourly Background Concentrations/Fluxes?
                              (LBACK)  -- Default: F   ! LBACK =  F !

Source information
------------------

  Option to process source contributions:
         0 =  Process only total reported contributions
         1 =  Sum all individual source contributions and process
         2 =  Run in TRACEBACK mode to identify source
              contributions at a SINGLE receptor
                             (MSOURCE) -- Default: 0   ! MSOURCE =  0  !

Receptor information
```

```
--------------------

  Gridded receptors processed?    (LG) -- Default: F   ! LG  = F  !
  Discrete receptors processed?   (LD) -- Default: F   ! LD  = T  !
  CTSG Complex terrain receptors processed?
                                 (LCT) -- Default: F   ! LCT = F  !

--Report results by DISCRETE receptor RING?
  (only used when LD = T)     (LDRING) -- Default: F   ! LDRING = F  !

--Select range of DISCRETE receptors (only used when LD = T):

  Select ALL DISCRETE receptors by setting NDRECP flag to -1;
                              OR
  Select SPECIFIC DISCRETE receptors by entering a flag (0,1) for each
     0 = discrete receptor not processed
     1 = discrete receptor processed
  using repeated value notation to select blocks of receptors:
     23*1, 15*0, 12*1
  Flag for all receptors after the last one assigned is set to 0
  (NDRECP) -- Default: -1
                                        alla    ! NDRECP =         693*1,2848*0   !



--Select range of GRIDDED receptors (only used when LG = T):

       X index of LL corner (IBGRID) -- Default: -1     ! IBGRID = -1  !
           (-1 OR 1 <= IBGRID <= NX)

       Y index of LL corner (JBGRID) -- Default: -1     ! JBGRID = -1  !
           (-1 OR 1 <= JBGRID <= NY)

       X index of UR corner (IEGRID) -- Default: -1     ! IEGRID = -1  !
           (-1 OR 1 <= IEGRID <= NX)

       Y index of UR corner (JEGRID) -- Default: -1     ! JEGRID = -1  !
           (-1 OR 1 <= JEGRID <= NY)

  Note: Entire grid is processed if IBGRID=JBGRID=IEGRID=JEGRID=-1


--Specific gridded receptors can also be excluded from CALPOST
  processing by filling a processing grid array with 0s and 1s.  If the
  processing flag for receptor index (i,j) is 1 (ON), that receptor
  will be processed if it lies within the range delineated by IBGRID,
  JBGRID,IEGRID,JEGRID and if LG=T. If it is 0 (OFF), it will not be
  processed in the run.  By default, all array values are set to 1 (ON).

  Number of gridded receptor rows provided in Subgroup (1a) to
  identify specific gridded receptors to process
                         (NGONOFF) -- Default: 0      ! NGONOFF =  0  !
```

```
!END!


--------------
Subgroup (1a) -- Specific gridded receptors included/excluded
--------------

    Specific gridded receptors are excluded from CALPOST processing
    by filling a processing grid array with 0s and 1s.  A total of
    NGONOFF lines are read here.  Each line corresponds to one 'row'
    in the sampling grid, starting with the NORTHERNMOST row that
    contains receptors that you wish to exclude, and finishing with
    row 1 to the SOUTH (no intervening rows may be skipped).  Within
    a row, each receptor position is assigned either a 0 or 1,
    starting with the westernmost receptor.
       0 = gridded receptor not processed
       1 = gridded receptor processed

    Repeated value notation may be used to select blocks of receptors:
       23*1, 15*0, 12*1

    Because all values are initially set to 1, any receptors north of
    the first row entered, or east of the last value provided in a row,
    remain ON.

    (NGXRECP) -- Default: 1


-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Visibility Parameters (ASPEC = VISIB)
--------------

    Identify the Base Time Zone for the CALPUFF simulation
                              (BTZONE) -- No default    ! BTZONE =  8.0!

    Particle growth curve f(RH) for hygroscopic species
                                (MFRH) -- Default: 2    ! MFRH   =  2  !

         1 =  IWAQM (1998) f(RH) curve (originally used with MVISBK=1)
         2 =  FLAG (2000) f(RH) tabulation
         3 =  EPA (2003) f(RH) tabulation

    Maximum relative humidity (%) used in particle growth curve
                               (RHMAX) -- Default: 98   ! RHMAX  = 95.0 !

    Modeled species to be included in computing the light extinction
     Include SULFATE?          (LVSO4) -- Default: T    ! LVSO4  = T  !
     Include NITRATE?          (LVNO3) -- Default: T    ! LVNO3  = T  !
     Include ORGANIC CARBON?   (LVOC)  -- Default: T    ! LVOC   = T  !
     Include COARSE PARTICLES? (LVPMC) -- Default: T    ! LVPMC  = T  !
```

```
     Include FINE PARTICLES?   (LVPMF) -- Default: T   ! LVPMF  = T  !
     Include ELEMENTAL CARBON? (LVEC)  -- Default: T   ! LVEC   = T  !

    And, when ranking for TOP-N, TOP-50, and Exceedance tables,
     Include BACKGROUND?       (LVBK)  -- Default: T   ! LVBK   = F  !

    Species name used for particulates in MODEL.DAT file
                   COARSE    (SPECPMC) -- Default: PMC ! SPECPMC = PMC !
                   FINE      (SPECPMF) -- Default: PMF ! SPECPMF = PMF !

Extinction Efficiency (1/Mm per ug/m**3)
----------------------------------------
    MODELED particulate species:
               PM  COARSE      (EEPMC) -- Default: 0.6 ! EEPMC  = 0.6 !
               PM  FINE        (EEPMF) -- Default: 1.0 ! EEPMF  = 1.0 !
    BACKGROUND particulate species:
               PM  COARSE    (EEPMCBK) -- Default: 0.6 ! EEPMCBK = 0.6 !
    Other species:
              AMMONIUM SULFATE (EESO4) -- Default: 3.0 ! EESO4  = 3.0 !
              AMMONIUM NITRATE (EENO3) -- Default: 3.0 ! EENO3  = 3.0 !
              ORGANIC CARBON   (EEOC)  -- Default: 4.0 ! EEOC   = 4.0 !
              SOIL             (EESOIL)-- Default: 1.0 ! EESOIL = 1.0 !
              ELEMENTAL CARBON (EEEC)  -- Default: 10. ! EEEC   = 10.0 !

Background Extinction Computation
---------------------------------

    Method used for the 24h-average of percent change of light extinction:
    Hourly ratio of source light extinction / background light extinction
    is averaged?              (LAVER) -- Default: F   ! LAVER = F  !


    Method used for background light extinction
                             (MVISBK) -- Default: 2   ! MVISBK =  2  !

         1 =  Supply single light extinction and hygroscopic fraction
              - Hourly F(RH) adjustment applied to hygroscopic background
                and modeled sulfate and nitrate
         2 =  Compute extinction from speciated PM measurements (A)
              - Hourly F(RH) adjustment applied to observed and modeled sulfate
                and nitrate
              - F(RH) factor is capped at F(RHMAX)
         3 =  Compute extinction from speciated PM measurements (B)
              - Hourly F(RH) adjustment applied to observed and modeled sulfate
                and nitrate
              - Receptor-hour excluded if RH>RHMAX
              - Receptor-day excluded if fewer than 6 valid receptor-hours
         4 =  Read hourly transmissometer background extinction measurements
              - Hourly F(RH) adjustment applied to modeled sulfate and nitrate
              - Hour excluded if measurement invalid (missing, interference,
                or large RH)
              - Receptor-hour excluded if RH>RHMAX
```

```
              - Receptor-day excluded if fewer than 6 valid receptor-hours
         5 =  Read hourly nephelometer background extinction measurements
              - Rayleigh extinction value (BEXTRAY) added to measurement
              - Hourly F(RH) adjustment applied to modeled sulfate and nitrate
              - Hour excluded if measurement invalid (missing, interference,
                or large RH)
              - Receptor-hour excluded if RH>RHMAX
              - Receptor-day excluded if fewer than 6 valid receptor-hours
         6 =  Compute extinction from speciated PM measurements
              - FLAG monthly RH adjustment factor applied to observed and
                modeled sulfate and nitrate
         7 =  Use observed weather or prognostic weather information for
              background extinction during weather events; otherwise, use Method 2
              - Hourly F(RH) adjustment applied to modeled sulfate and nitrate
              - F(RH) factor is capped at F(RHMAX)
              - During observed weather events, compute Bext from visual range
                if using an observed weather data file, or
              - During prognostic weather events, use Bext from the prognostic
                weather file
              - Use Method 2 for hours without a weather event

Additional inputs used for MVISBK = 1:
--------------------------------------
 Background light extinction (1/Mm)
                          (BEXTBK) -- No default   ! BEXTBK = 0.0 !
 Percentage of particles affected by relative humidity
                          (RHFRAC) -- No default   ! RHFRAC = 0.0 !

Additional inputs used for MVISBK = 6:
--------------------------------------
 Extinction coefficients for hygroscopic species (modeled and
 background) are computed using a monthly RH adjustment factor
 in place of an hourly RH factor (VISB.DAT file is NOT needed).
 Enter the 12 monthly factors here (RHFAC).  Month 1 is January.

 (RHFAC)  -- No default     ! RHFAC = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !

Additional inputs used for MVISBK = 7:
--------------------------------------
 The weather data file (DATSAV abbreviated space-delimited) that
 is identified as VSRN.DAT may contain data for more than one
 station.  Identify the stations that are needed in the order in
 which they will be used to obtain valid weather and visual range.
 The first station that contains valid data for an hour will be
 used.  Enter up to MXWSTA (set in PARAMS file) integer station IDs
 of up to 6 digits each as variable IDWSTA, and enter the corresponding
 time zone for each, as variable TZONE (= UTC-LST).

 A prognostic weather data file with Bext for weather events may be used
 in place of the observed weather file.  Identify this as the VSRN.DAT
```

```
     file and use a station ID of IDWSTA = 999999, and TZONE = 0.

     NOTE:  TZONE identifies the time zone used in the dataset.  The
            DATSAV abbreviated space-delimited data usually are prepared
            with UTC time rather than local time, so TZONE is typically
            set to zero.

     (IDWSTA)   -- No default
    ! IDWSTA = 999999 !
     (TZONE)    -- No default
    ! TZONE  = 0.0 !

    Additional inputs used for MVISBK = 2,3,6,7:
    --------------------------------------------
     Background extinction coefficients are computed from monthly
     CONCENTRATIONS of ammonium sulfate (BKSO4), ammonium nitrate (BKNO3),
     coarse particulates (BKPMC), organic carbon (BKOC), soil (BKSOIL), and
     elemental carbon (BKEC).  Month 1 is January.
     (ug/m**3)
       **FLAG 2000**

     (BKSO4)  -- No default     ! BKSO4 = .20, .20, .20, .20,
                                          .20, .20, .20, .20,
                                          .20, .20, .20, .20 !
     (BKNO3)  -- No default     ! BKNO3 = 0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0 !
     (BKSOIL)  -- No default     ! BKSOIL = 4.5, 4.5, 4.5, 4.5,
                                          4.5, 4.5, 4.5, 4.5,
                                          4.5, 4.5, 4.5, 4.5 !
     (BKOC)   -- No default     ! BKOC  = 0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0 !
     (BKPMC) -- No default     ! BKPMC = 0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0 !
     (BKEC)   -- No default     ! BKEC  = 0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0,
                                          0.0, 0.0, 0.0, 0.0 !

    Additional inputs used for MVISBK = 2,3,5,6,7:
    ----------------------------------------------
     Extinction due to Rayleigh scattering is added (1/Mm)
                              (BEXTRAY) -- Default: 10.0 ! BEXTRAY = 10.0 !

!END!
--------------------------------------------------------------------------------

INPUT GROUP: 3 -- Output options
--------------

Documentation
```

```
-------------

    Documentation records contained in the header of the
    CALPUFF output file may be written to the list file.
    Print documentation image?
                                (LDOC) -- Default: F   !  LDOC = F !

Output Units
------------
    Units for All Output       (IPRTU) -- Default: 1   ! IPRTU =  3   !
                     for              for
                Concentration    Deposition
       1 =         g/m**3         g/m**2/s
       2 =        mg/m**3        mg/m**2/s
       3 =        ug/m**3        ug/m**2/s
       4 =        ng/m**3        ng/m**2/s
       5 =      Odour Units

    Visibility: extinction expressed in 1/Mega-meters (IPRTU is ignored)


Averaging time(s) reported
--------------------------

    1-hr averages           (L1HR) -- Default: T   !   L1HR = F  !

    3-hr averages           (L3HR) -- Default: T   !   L3HR = F  !

    24-hr averages         (L24HR) -- Default: T   !  L24HR = T  !

    Run-length averages    (LRUNL) -- Default: T   !  LRUNL = F  !

    User-specified averaging time in hours, minutes, seconds
    - results for this averaging time are reported if it is not zero

                           (NAVG) -- Default: 0   !   NAVG =  0  !


Types of tabulations reported
------------------------------

   1) Visibility: daily visibility tabulations are always reported
                  for the selected receptors when ASPEC = VISIB.
                  In addition, any of the other tabulations listed
                  below may be chosen to characterize the light
                  extinction coefficients.
                  [List file or Plot/Analysis File]


   2) Top 50 table for each averaging time selected
      [List file only]
                            (LT50) -- Default: T   !   LT50 = F  !
```

```
3) Top 'N' table for each averaging time selected
   [List file or Plot file]
                        (LTOPN) -- Default: F   !  LTOPN = T  !

     -- Number of 'Top-N' values at each receptor
        selected (NTOP must be <= 4)
                         (NTOP) -- Default: 4   ! NTOP =  1   !

     -- Specific ranks of 'Top-N' values reported
        (NTOP values must be entered)
                (ITOP(4) array) -- Default:     ! ITOP =  1 !
                                   1,2,3,4


4) Threshold exceedance counts for each receptor and each averaging
   time selected
   [List file or Plot file]
                        (LEXCD) -- Default: F   !  LEXCD = F  !

     -- Identify the threshold for each averaging time by assigning a
        non-negative value (output units).

                                -- Default: -1.0
        Threshold for  1-hr averages   (THRESH1) !  THRESH1 = -1.0  !
        Threshold for  3-hr averages   (THRESH3) !  THRESH3 = -1.0  !
        Threshold for 24-hr averages  (THRESH24) ! THRESH24 = -1.0  !
        Threshold for NAVG-hr averages (THRESHN) !  THRESHN = -1.0  !


     -- Counts for the shortest averaging period selected can be
        tallied daily, and receptors that experience more than NCOUNT
        counts over any NDAY period will be reported.  This type of
        exceedance violation output is triggered only if NDAY > 0.

        Accumulation period(Days)
                         (NDAY) -- Default: 0   !    NDAY =  0  !
        Number of exceedances allowed
                       (NCOUNT) -- Default: 1   !  NCOUNT =  1  !


5) Selected day table(s)

   Echo Option -- Many records are written each averaging period
   selected and output is grouped by day
   [List file or Plot file]
                        (LECHO) -- Default: F   !  LECHO = F  !

   Timeseries Option -- Averages at all selected receptors for
   each selected averaging period are written to timeseries files.
   Each file contains one averaging period, and all receptors are
   written to a single record each averaging time.
```

```
      [TSERIES_ASPEC_ttHR_CONC_TSUNAM.DAT files]
                           (LTIME) -- Default: F    !  LTIME = F  !

      Peak Value Option -- Averages at all selected receptors for
      each selected averaging period are screened and the peak value
      each period is written to timeseries files.
      Each file contains one averaging period.
      [PEAKVAL_ASPEC_ttHR_CONC_TSUNAM.DAT files]
                           (LPEAK) -- Default: F    !  LPEAK = F  !

        -- Days selected for output
                      (IECHO(366)) -- Default: 366*0
           ! IECHO  = 366*0  !
           (366 values must be entered)

Plot output options
-------------------

     Plot files can be created for the Top-N, Exceedance, and Echo
     tables selected above.  Two formats for these files are available,
     DATA and GRID.  In the DATA format, results at all receptors are
     listed along with the receptor location [x,y,val1,val2,...].
     In the GRID format, results at only gridded receptors are written,
     using a compact representation.  The gridded values are written in
     rows (x varies), starting with the most southern row of the grid.
     The GRID format is given the .GRD extension, and includes headers
     compatible with the SURFER(R) plotting software.

     A plotting and analysis file can also be created for the daily
     peak visibility summary output, in DATA format only.

     Generate Plot file output in addition to writing tables
     to List file?
                                 (LPLT) -- Default: F    ! LPLT  = T !

     Use GRID format rather than DATA format,
     when available?
                                 (LGRD) -- Default: F    ! LGRD  = F !


Auxiliary Output Files (for subsequent analyses)
------------------------------------------------

      Visibility

      A separate output file may be requested that contains the change
      in visibility at each selected receptor when ASPEC = VISIB.  This
      file can be processed to construct visibility measures that are
      not available in CALPOST.

      Output file with the visibility change at each receptor?
                                (MDVIS) -- Default: 0    ! MDVIS  =  2  !
```

```
          0 =  Do Not create file
          1 =  Create file of DAILY (24 hour) Delta-Deciview
          2 =  Create file of DAILY (24 hour) Extinction Change (%)
          3 =  Create file of HOURLY Delta-Deciview
          4 =  Create file of HOURLY Extinction Change (%)


Additional Debug Output
-----------------------

   Output selected information to List file
    for debugging?
                              (LDEBUG) -- Default: F  ! LDEBUG  = F !

   Output hourly extinction information to REPORT.HRV?
    (Visibility Method 7)
                             (LVEXTHR) -- Default: F  ! LVEXTHR = F !

!END!
```

Appendix A-4

Ozone Impact Analysis

Ozone Impact Analysis

Grays Harbor Energy
Units 3 &4

Prepared for:
Grays Harbor Energy, LLC
Elma, Washington

Prepared by:
ENVIRON International Corporation
Lynnwood, Washington

Date:
July 2009

Project Number:
29-22706A

ENVIRON

Contents

1 Introduction

This analysis of ozone impacts attributable to the Grays Harbor Energy Center (GHEC) facility has been prepared by ENVIRON International, Inc. (ENVIRON) in support of a combined Prevention of Deterioration (PSD) and Notice of Construction (NOC) application. The proposal is to increase the facility's overall capacity by adding two more combined-cycle combustion turbines and a second steam turbine (referred to as Units 3 and 4).

Title 40 of the Code of Federal Regulations, Section 52.21(i)(5)(i)(3) requires an ambient ozone impact analysis be performed for any net emissions increase of 100 tons per year (TPY) of more of volatile organic compounds (VOCs) or oxides of nitrogen (NOx). VOC and NOx emissions attributable to the current proposal each exceed 100 TPY. The ozone impact analysis was performed using the Community Multiscale Air Quality (CMAQ) dispersion model. Two simulations were developed: a base case scenario which included all existing regional emissions other than the GHEC facility, and a potential-to-emit (PTE) scenario which combined the base case scenario emissions with the GHEC facility's maximum post-project emissions. The ozone concentrations predicted by the two simulations were compared to determine the ozone impact attributable to the project.

The modeling simulations were based on those developed by the Washington State University (WSU) Laboratory for Atmospheric Research in support of a state implementation plan (SIP) for Ozone for the Portland, OR/Vancouver, WA region. This is essentially the same dataset used by WSU as the base case scenario to analyze future emission scenarios for the Puget Sound Clean Air Agency (PSCAA). In those analyses, as well as this, a three-day period beginning July 26, 1998 was selected because the episode had the highest observed ozone levels in recent years for the Seattle/Portland airshed. ENVIRON obtained input and output files from WSU for this episode.

2 Model Description

The modeling system used for this work was the Mesoscale Meteorological model Version 5 (MM5)/Sparse Matrix Operator Kernel Emissions (SMOKE)/CMAQ system. Each component is independent: MM5 supplies the meteorology, SMOKE pre-processes emissions information, and CMAQ combines the emissions with the meteorology to calculate concentrations.

MM5 (Grell et al., 1994) was used to provide the 3-D meteorological field for air quality modeling. Three one-way nested domains with grid cell horizontal sizes of 36 km, 12 km, and 4 km were applied. The two outer domains consisted of 98x95 and 133x151 grid cells, respectively. The innermost domain consisted of 112x112 grid cells which extended from north of Puget Sound in Washington to south of Salem, OR and from the Pacific coast on the west to beyond the Cascade Mountain range on the east. Vertically, 38 sigma layers were specified. WSU performed a sensitivity analysis and determined that using the more advanced land surface model (NOAH LSM) produced the best overall results for air quality modeling. A detailed analysis is available in the Portland SIP report.

The SMOKE Modeling System allows emissions data processing methods to integrate high-performance-computing (HPC) sparse-matrix algorithms. It provides a mechanism for preparing specialized inputs for air quality modeling research, and it makes air quality forecasting possible. Although version 2.5 is the most recent available version, ENVIRON used SMOKE version 2.1 to maintain compatibility with the emissions inventory of the previous WSU modeling. Emissions classes included biogenic, area, non-road mobile, on-road mobile, and industrial point sources. Emissions inventories obtained from WSU for Oregon, Washington and British Columbia were included.

EPA Models-3 CMAQ Modeling System (Byun and Ching, 1999) version 4.6 was used for photochemical air quality modeling. Based on state-of-science techniques, CMAQ is a multi-scale, multi-pollutant air quality model that simulates the transportation, transformation, and deposition of atmospheric pollutants including photochemical precursors and oxidants, particulate matter, and airborne toxics. It simulates chemical transport using the CMAQ Chemical Transport Model (CCTM) by incorporating the output fields from the MM5 meteorological simulations and emissions derived from SMOKE.

The [California] Statewide Air Pollution Research Center (SAPRC99) photochemical mechanism, including aqueous chemistry, was used, but the aerosol dynamics module was not employed due to the lack of emission inventory data for key aerosol precursors. Chemical speciation of the emission inventory was performed by SMOKE according to the SAPRC99 mechanism. The Modified Euler Backward Interactive (MEBI) solver was used to solve the chemical kinetic equations.

3 Source Description

The base case scenario emissions inventory is based on the 1999 National Emissions Inventory, using its point sources, area sources and some non-road sources (ships, locomotives, aircraft, etc.). A detailed discussion of the base case scenario emission inventory is presented in the appendixes of the WSU SIP and PSCAA reports.

The PTE scenario included all the emissions in the base case, plus the point sources associated with this project. Because the ozone analysis is concerned with regional impacts that are generally distant from the facility, the ten cooling towers were represented in the model by a single stack with exhaust characteristics equivalent to a single tower but ten times the emissions. Emission rates are summarized in Table 3-1, and emission release parameters are provided in Table 3-2. These emission source data were prepared for use with CMAQ using SMOKE pre-processing programs.

The rates used are the maximum hourly emission rates for each pollutant, regardless of operating scenario. For example, the NOx and CO rates are their maxima for the startup/shutdown scenario, while the SO2 rate is its maximum for the continuous operation scenario.

Table 1: Point source release parameters						
Source	**UTM X (m)**	**UTM Y (m)**	**Height (ft)**	**Temperature (ºF)**	**Velocity (ft/s)**	**Diameter (ft)**
CTG3	463675	5201629	180	160.78	66.14	18.00
CTG4	463718	5201627	180	160.78	66.14	18.00
AUXB2	463775	5201616	49	398.03	68.10	1.76
DG2	463748	5201628	13	909.90	310.25	0.50
FPMP2	463677	5201652	13	1032.00	238.59	0.42
CoolingTowers	463739	5201684	52	102.00	17.85	42.59

Table 2: Point source emission rates					
Source	**NOx (TPY)**	**SO2 (TPY)**	**PM10 (TPY)**	**CO (TPY)**	**VOC (TPY)**
CTG3	126.79	61.98	83.22	2013.39	127.16
CTG4	126.79	61.98	83.22	2013.39	127.16
AUXB2	1.4117	0.7412	0.6417	4.7484	0.5133
DG2	0.7203	0.0319	0.0360	15.1265	17.2875
FPMP2	0.2476	0.0146	0.0330	5.1508	5.9433
CoolingTowers	0	0	3.4527	0	0

4 Results

As a preliminary exercise, the base case scenario provided by WSU was replicated and the results compared to those reported by WSU. Figures 1 and 3 present the maximum predicted concentrations in parts per million by volume (ppmV) for the replicated base case, and Figures 2 and 4 present the corresponding plots from the WSU/PSCAA report (Figures 17a and 18a in that document). Qualitatively, the plots for the same time periods are similar, and differences between the corresponding plots are slight, with a less than two percent difference in the maximum predicted ozone concentration for the hours depicted. Perhaps the most notable feature is the increased ozone at the north end of Puget Sound in Figure 1, which is presumably attributable to sources in Canada. For the purposes of this modeling exercise, exact duplication of previous work is not necessary; this comparison is provided as confirmation that predictions from the more recent version of CMAQ are consistent with those of previous versions.

The Visualization Environment for Rich Data Interpretation (VERDI) was used to explore and visualize the differences between the base and PTE cases. The figures presented in the WSU/PSCAA report were prepared using The Package for Analysis and Visualization of Environmental data (PAVE), which is no longer supported. Unfortunately, certain features of PAVE have not been implemented in VERDI. These include the ability to smooth tile plots (creating contour-like plots shown in Figures 2 and 4) and the ability to plot N-hour average concentrations. CMAQ outputs 1-hour average concentrations only. The m3tproc program from the Input/Output Applications Programming Interface[1] (I/O API 3) was used to calculate 8-hour averages of ozone concentration.

The results of the base and PTE cases are small enough that a side-by-side visual comparison of the two plots is not useful for discerning differences. To facilitate examination of the differences between the two scenarios (the PTE scenario and the base case scenario), the remainder of the figures present concentration differences in parts per billion by volume (ppbV), a thousand-fold increase in the concentration scale used in Figures 1 through 4.

Figure 5 shows a time series plots of the ozone concentration difference at the cell with the maximum 8-hour average difference (an increase of 2.25 ppbV at cell 22,70). Figure 6 shows the spatial variation of the 8-hour average ozone concentration difference between the two scenarios during the period with the maximum difference (0900 PDT on July 28, 1998). As this figure shows, the effects of the facility's NOx and VOC emissions is quite localized.

Figures 7 through 11 present time series plots of 8-hour averaged differences in simulated ozone concentrations (PTE scenario minus base case scenario) near the closest Class I areas. As can be seen, the maximum change to 8-hour average ozone concentrations near Class I areas is less than 0.01 ppbV, which is less than 0.02 percent of the current ozone NAAQS.[2]

Figure 12 presents a time series of 8-hour averaged differences in simulated ozone concentrations (PTE scenario minus base case scenario) near the Mud Mountain site outside of Enumclaw, WA. The maximum difference is less than 0.0004 ppbV, which is close to the smallest number the program can resolve.

---

[1] http://www.baronams.com/products/ioapi/

[2] The current ozone NAAQS is 75 ppb. To attain this standard, the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm

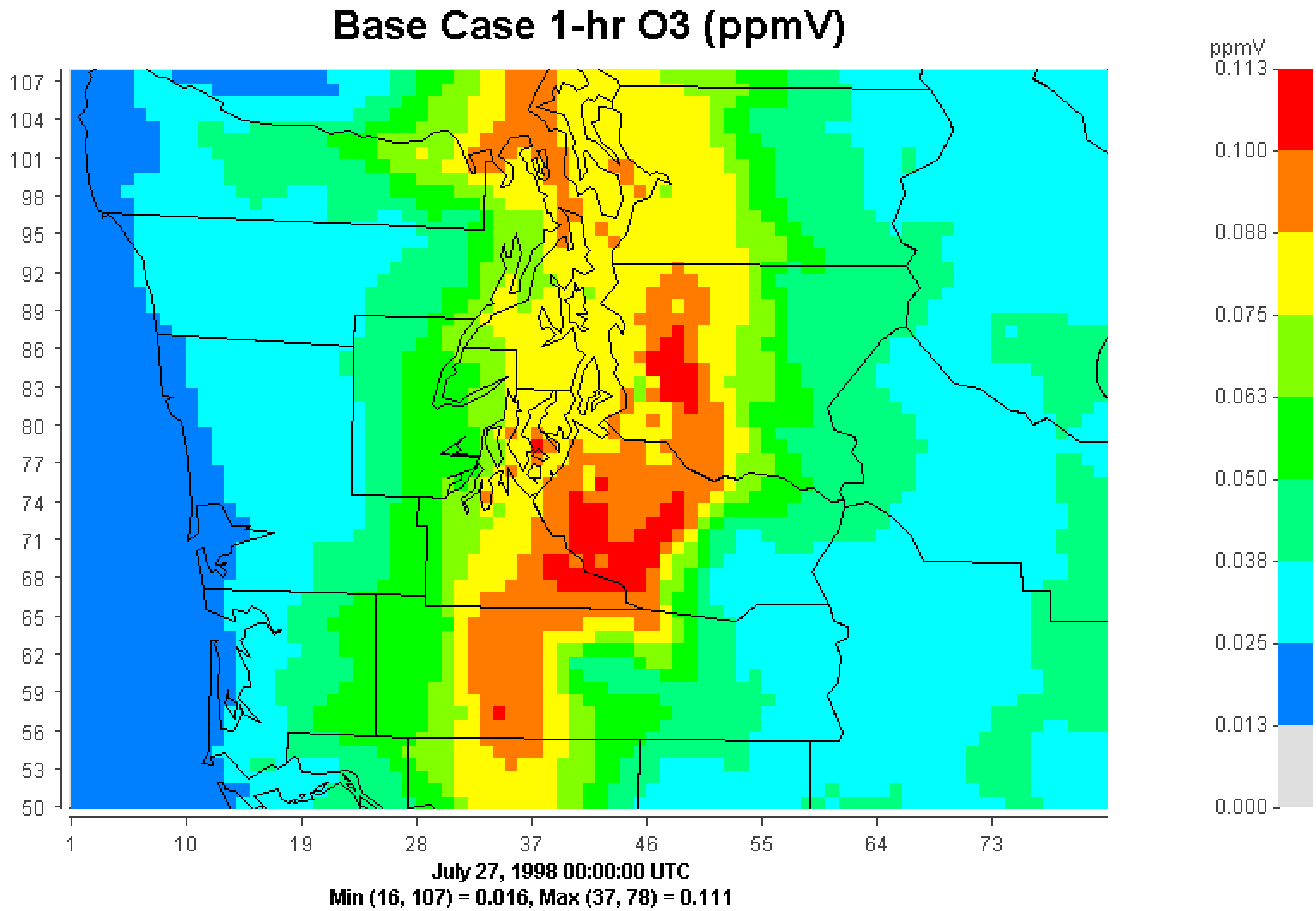


Figure 1 Simulated 1-Hour Average Ozone At 1700 PDT On July 26 (Base Case)

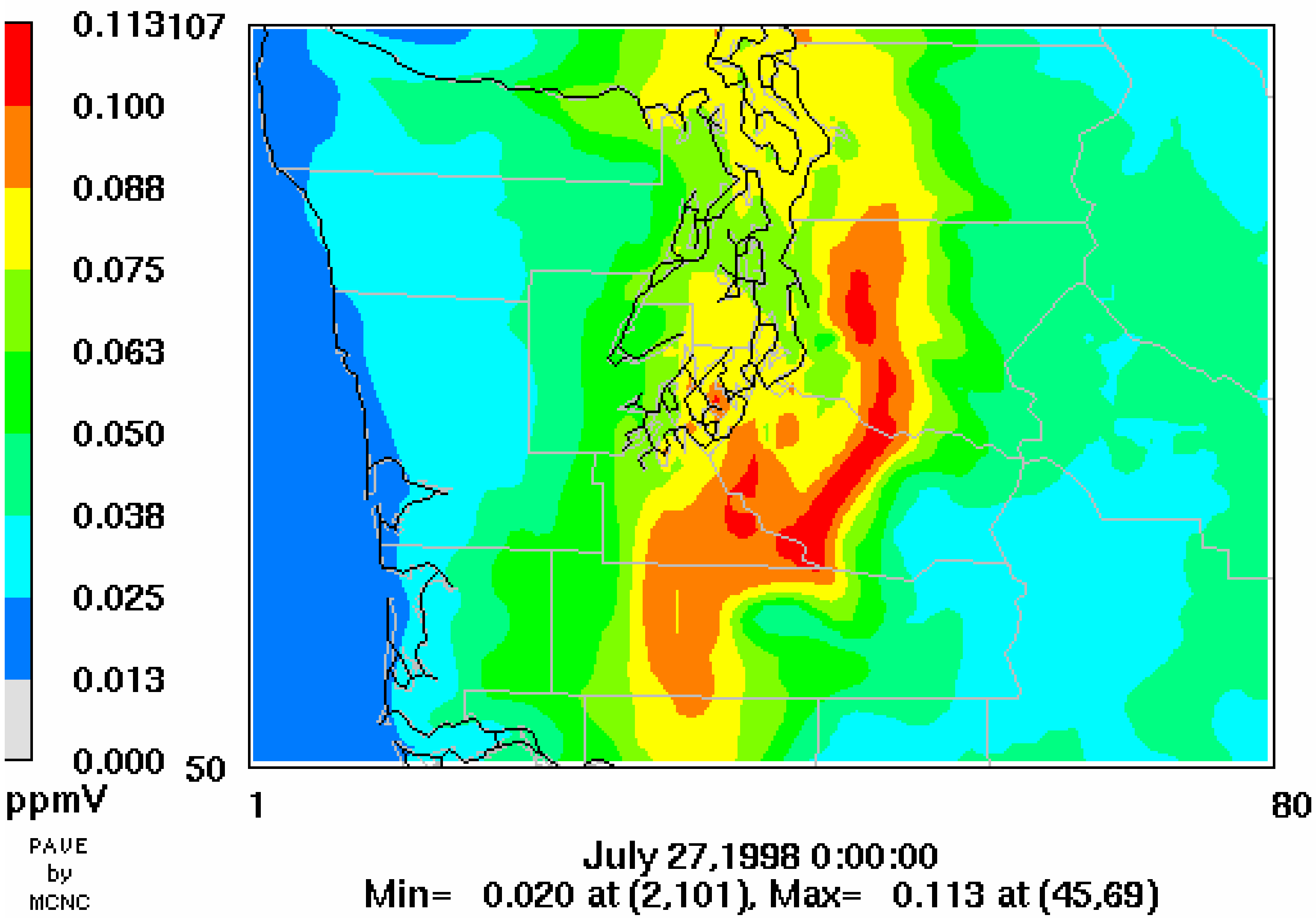


Figure 2 Figure 17a of the WSU/PSCAA Report

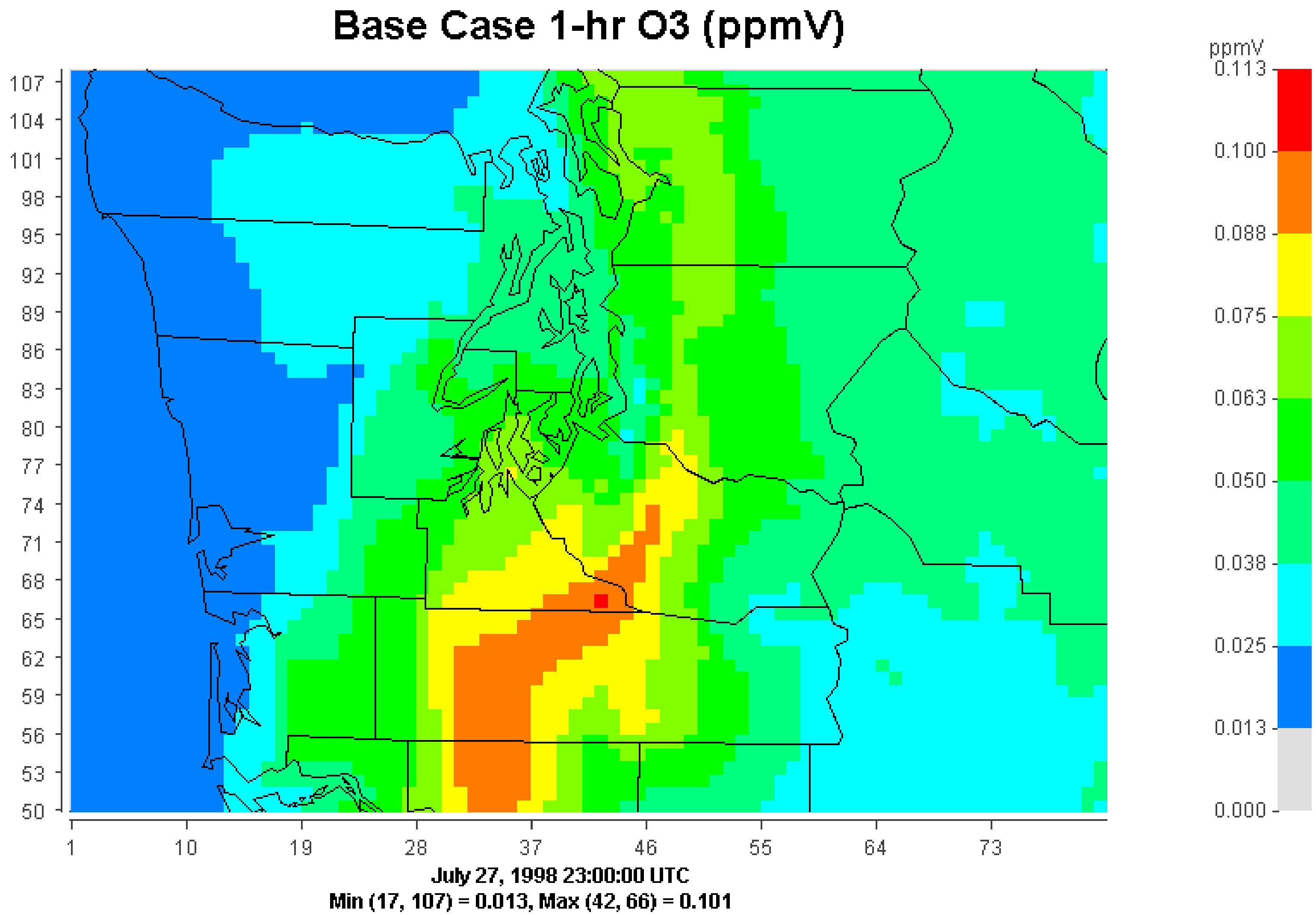


Figure 3 Simulated 1-Hour Average Ozone at 1600 PDT On July 27 (Base Case)

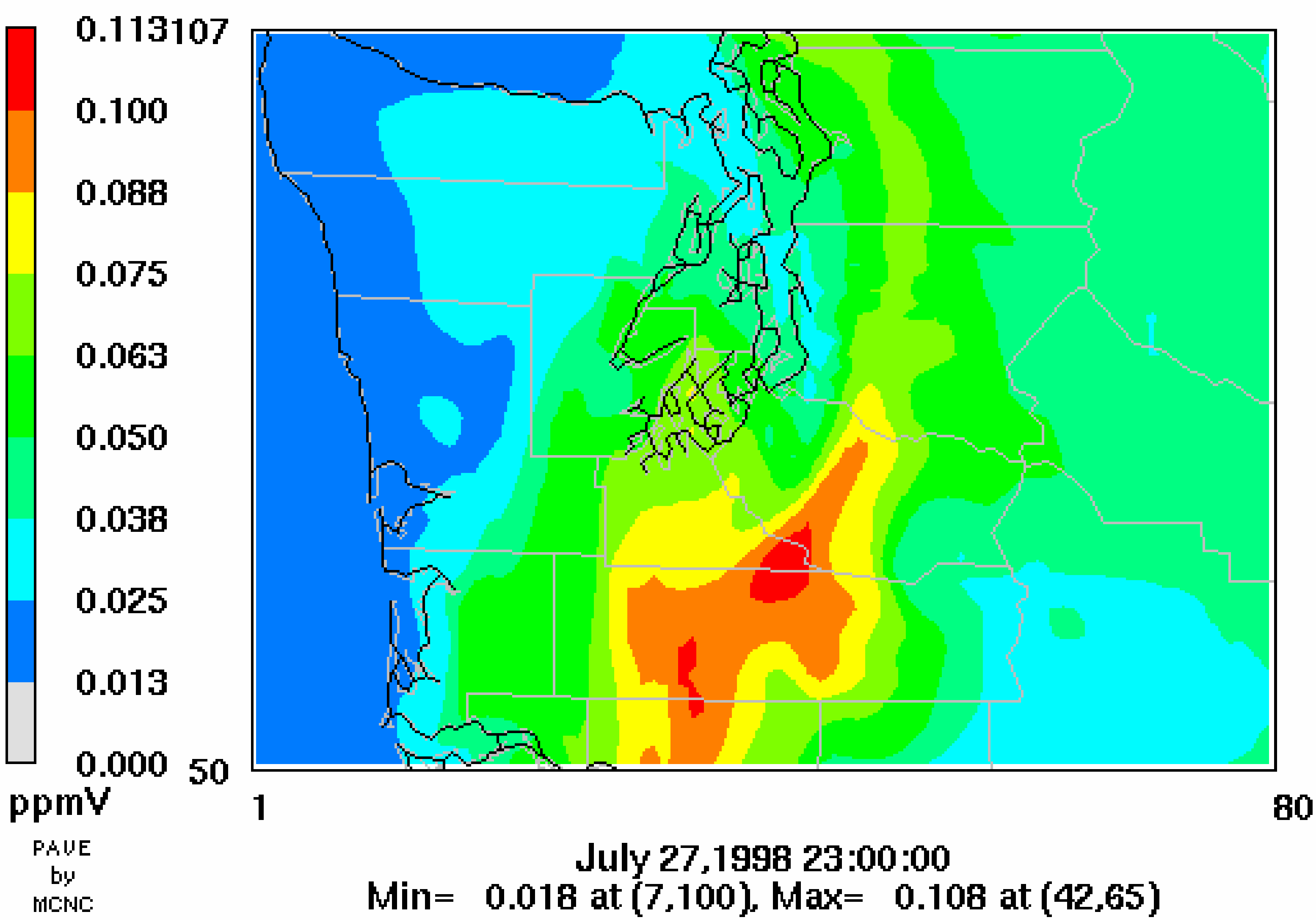


Figure 4 Figure 18a of the WSU/PSCAA Report

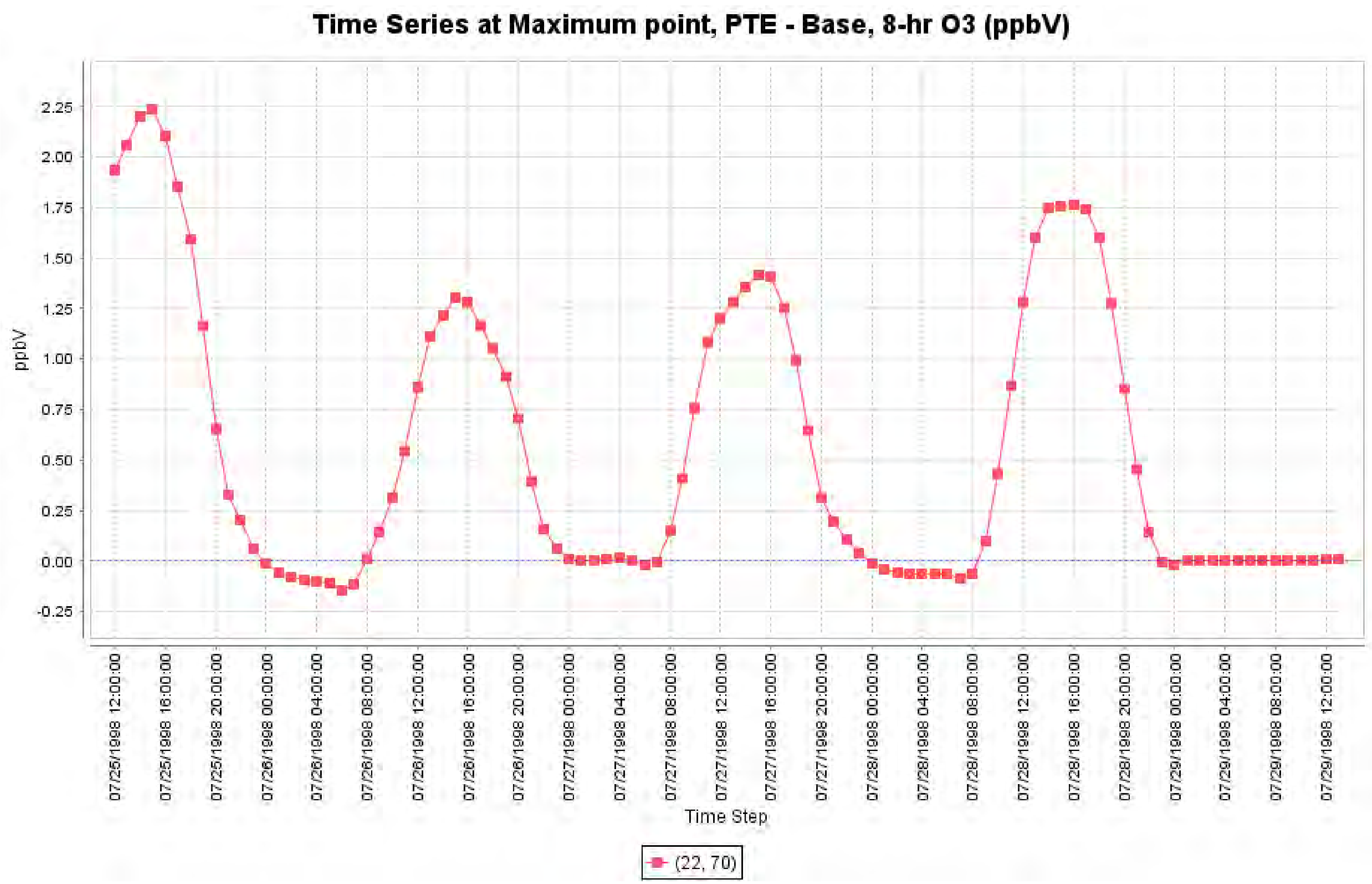


Figure 5 Time series at maximum point of PTE-Base 8-hour ozone

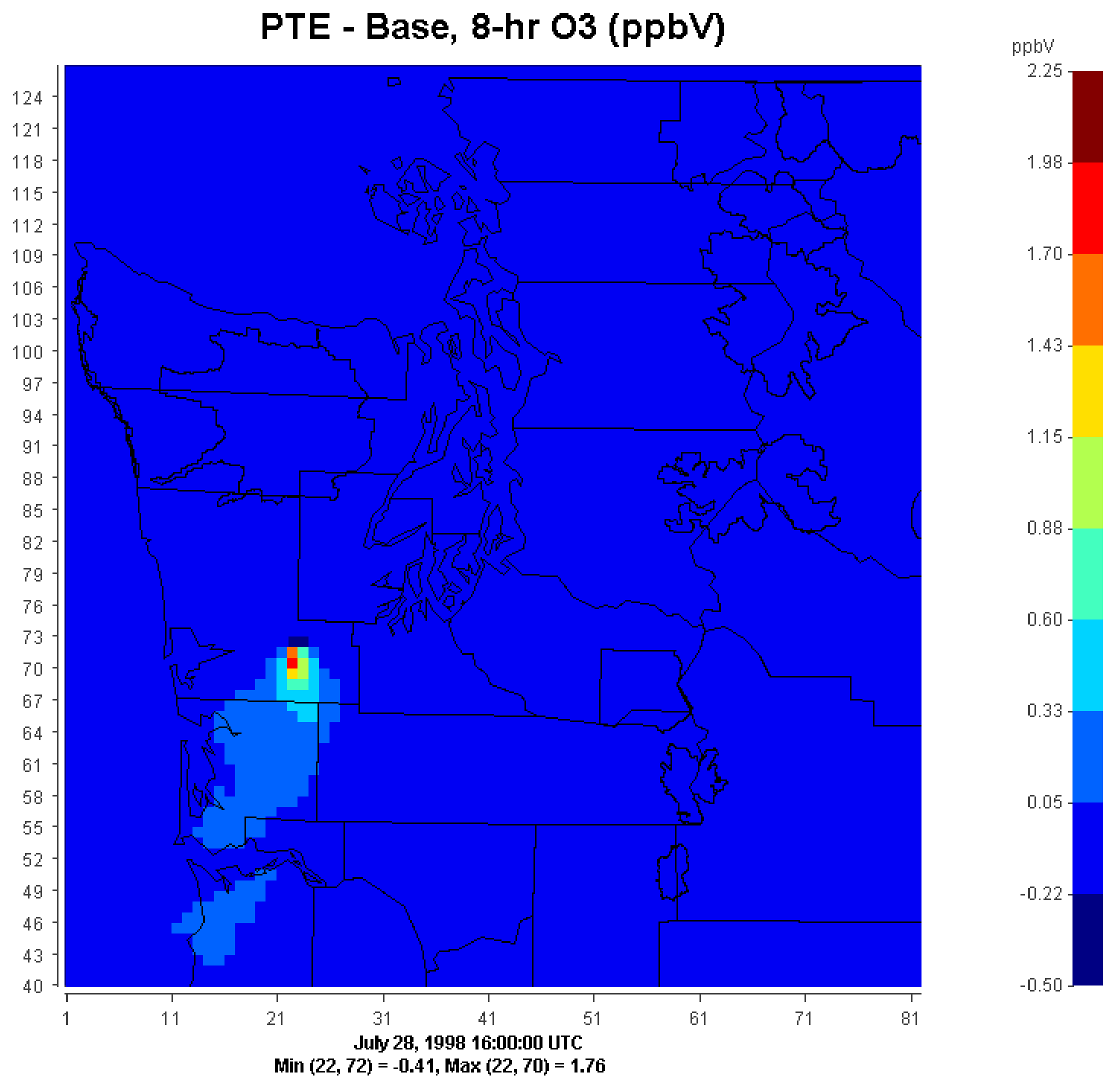


Figure 6 PTE-Base 8-hour ozone at time of maximum

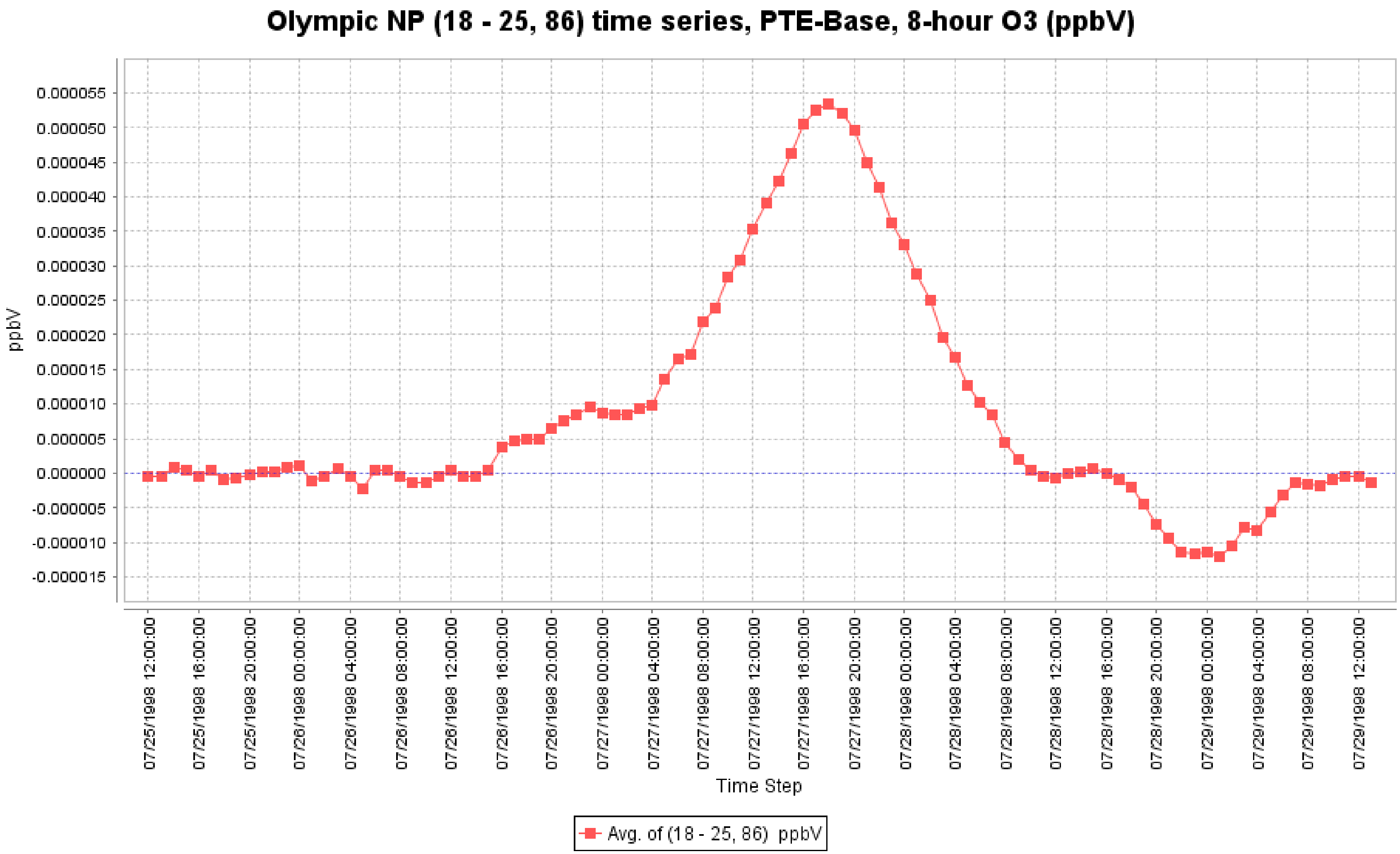


Figure 7 Time series of PTE-Base 8-hour ozone, southern edge of Olympic NP

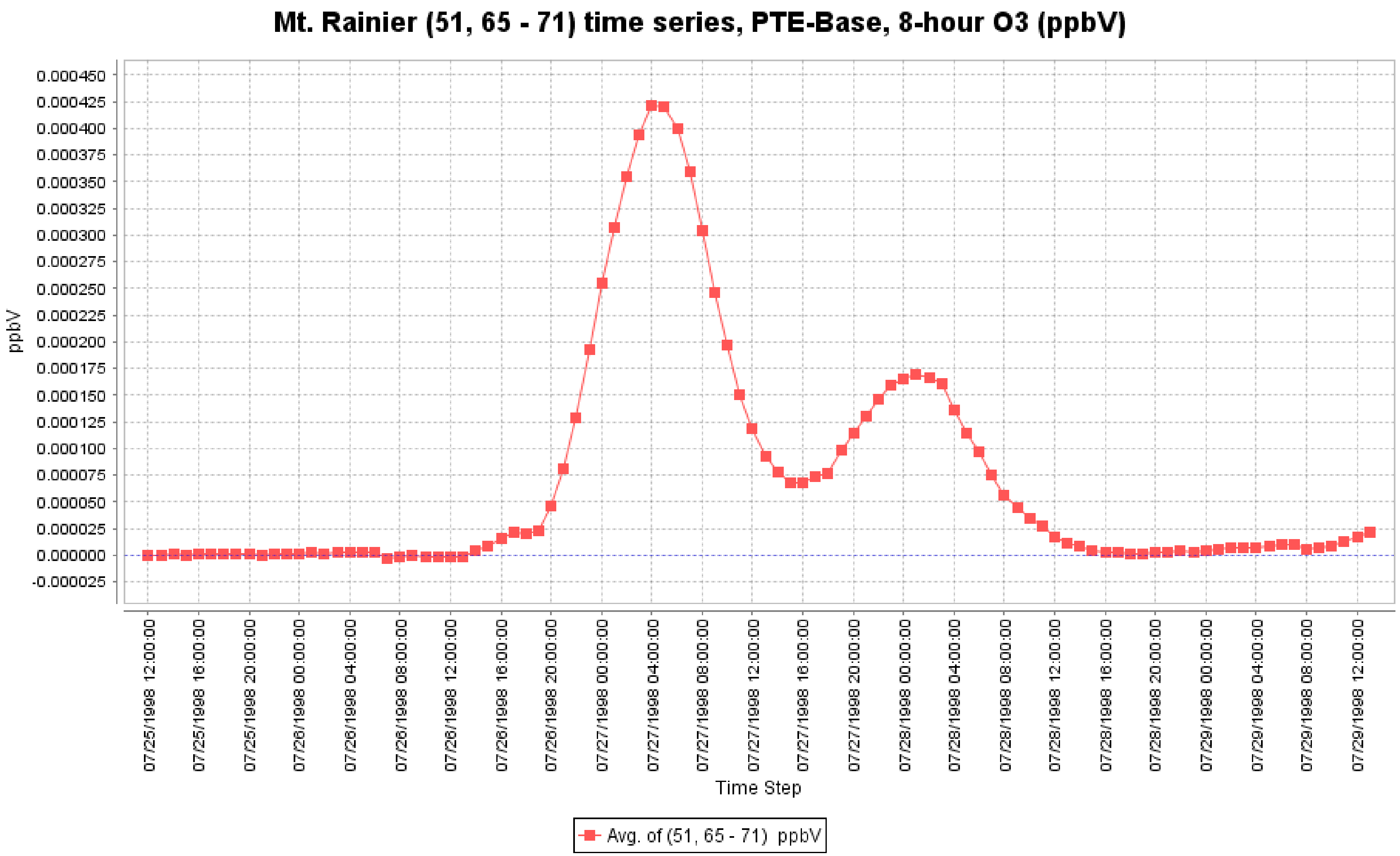


Figure 8 Time series of PTE-Base 8-hour ozone, western edge of Mt. Rainier

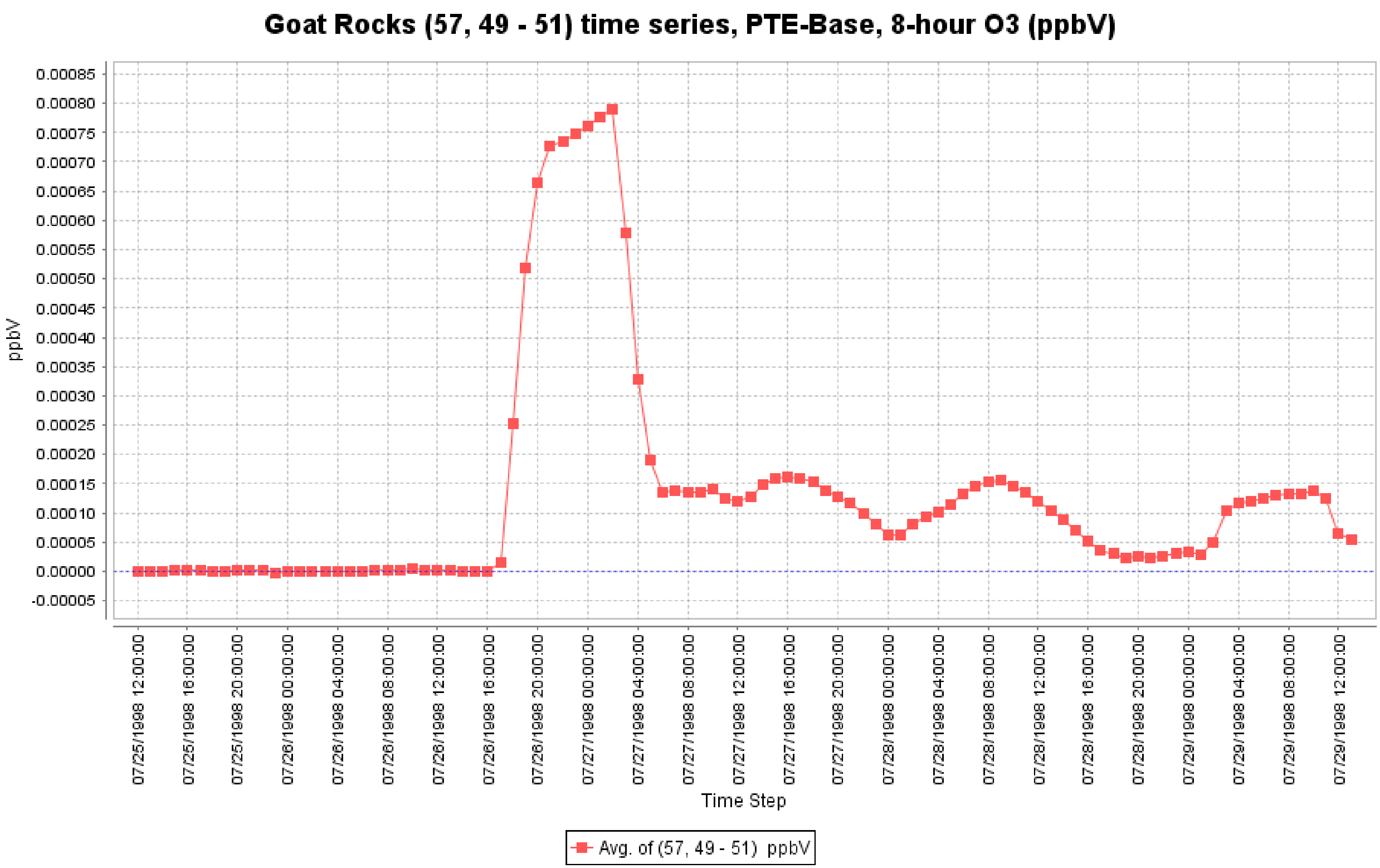


Figure 9 Time series of PTE-Base 8-hour ozone, western edge of Goat Rocks

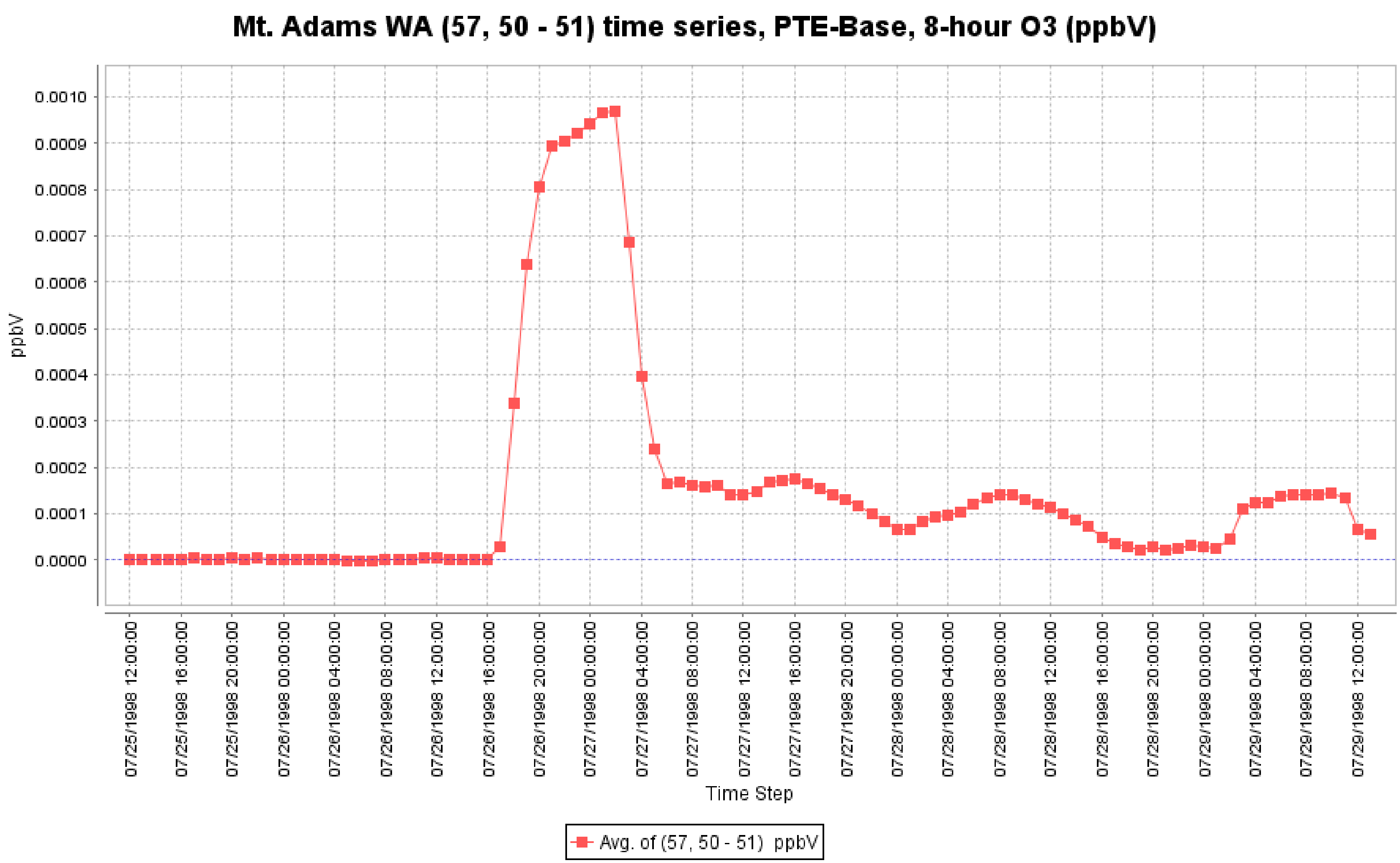


Figure 10 Time series of PTE-Base 8-hour ozone, western edge of Mt. Adams

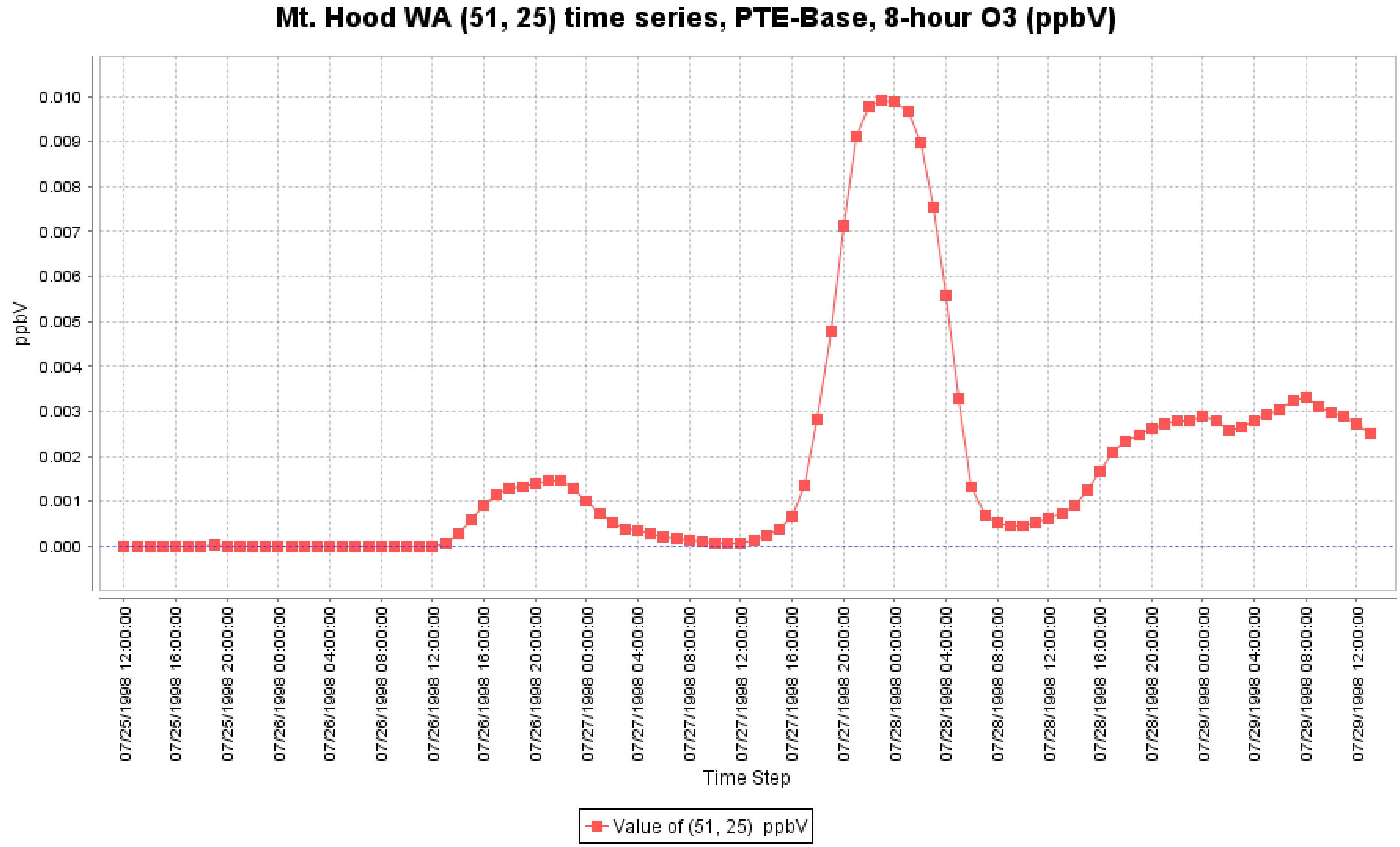


Figure 11 Time series of PTE-Base 8-hour ozone, at a point in Mt. Hood

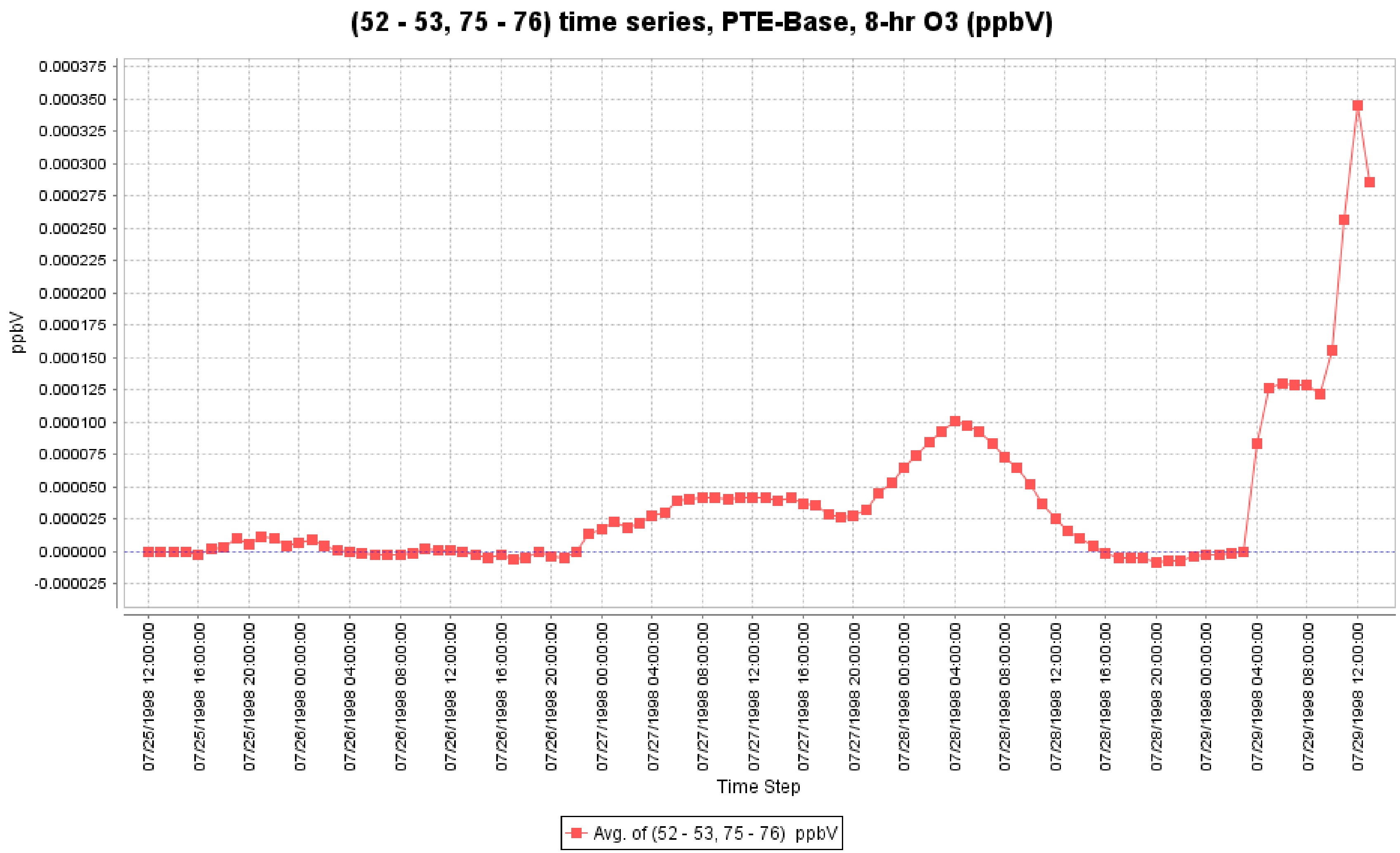


Figure 12 Time series of PTE-Base 8-hour ozone, near Enumclaw and Mud Mountain

5 Conclusions

ENVIRON acquired the relevant input data and control files and replicated the MM5/SMOKE/CMAQ runs performed by WSU for PSCAA and ODEQ in support of the various ozone studies conducted by those organizations. The scenarios in question simulate the 26-28 July 1998 ozone episode, which was meteorologically more severe than the 1996 case used previously. We performed a “base case” scenario that closely resembled those of the PSCAA and Portland SIP studies, and a “PTE scenario,” which was comprised of all base case scenario emissions in addition to the maximum post-project emissions from the facility.

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

The largest increase in 8-hour ozone concentration near a Class I area is about 0.01 ppbV near Mount Hood Wilderness Area. This is less than 1 percent of the relevant NAAQS, indicating that the facility will not cause or significantly contribute to degradation of our natural wild areas. The largest increase in 8-hour ozone concentration near the Enumclaw (Mud Mountain) observation site is less than 0.0004 ppbV.

6 References

Grell, G. A., J. Dudhia, and D. R. Stauffer, 1994: *A description ofthe fifth-generation Penn State/NCAR Mesoscale Model (MM5),* NCAR Tech. Note, NCAR/TN-398+STR, 122pp.

Byun, D.W. and Ching, J.K.S., editors. 1999: *Science Algorithms of the EPA Models-3 Community Multiscale Air Quality (CMAQ) Modeling System*. U.S. Environmental Protection Agency, Office of Research and Development. EPA/600/R-99/030.

Ying Xie and Brian Lamb, 2005: *Historical and Future Ozone Simulations using the MM5/SMOKE/CMAQ System in the Portland/Vancouver Area*, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU. December 31, 2005.

Brian Lamb and Ying Xie, Laboratory of Atmospheric Research, Department of Civil & Environmental Engineering, WSU; Clint Bowman, Sally Otterson, and Doug Schneider, Washington State Department of Ecology; and Kathy Himes, John Anderson, Kwame Agyei, and Beth Carper, PSCAA, 2006: *Modeling Analysis of Future Emission Scenarios for Ozone Impacts in the Puget Sound Area*, August, 2006.

Appendix B

Acoustical Terminology and Concepts Used in Noise Modeling

Noise Definitions

Noise

Noise is generally defined as loud, unpleasant, unexpected, or undesired sound that interferes or disrupts normal activities. Although exposure to high noise levels has been demonstrated to cause hearing loss, the principal human response to environmental noise is annoyance. Reaction of individuals to similar noise events is diverse and influenced by numerous factors, such as the type of noise, its perceived importance, the time of day during which the noise occurs, its duration, frequency, level, etc.

Sound Level Meters

Noise is measured using a standardized instrument called a 'sound level meter'. All sound level meters are equipped with small microphones that detect minute changes in atmospheric pressure caused by the mechanical vibration of air molecules. Healthy human hearing can detect pressures as low as 0.00002 Pascals (threshold of hearing) and as high as 100 Pascals (threshold of pain).[1] Since this dynamic range is enormous (greater than one million to one), sound pressures are instead reported using a logarithmic scale, which compresses the numbers to keep them more manageable. Once converted, they are referred to as sound pressure levels, followed by 'decibels' (abbreviated dB) as the unit of measure. On a logarithmic scale, the threshold of hearing and the threshold of pain become 0 and about 130 decibels, respectively.

A-Weighted Levels

Noise is generally characterized by amplitude (level) and by frequency (pitch). Amplitude can be reported using various human-perception scales, similar to reporting temperature in terms of wind chill or heat index, or humidity in terms of dew point. The latter are better indicators of perceived cold, warmth or dampness, respectively. Similarly, sound level measurements are often reported using the 'A-weighting' scale of a sound level meter. A-weighting slightly boosts high frequency sound, while reducing low frequency components (similar to the way stereo bass and treble controls work), providing a better indicator of perceived loudness at relatively modest volumes. These measures are called A-weighted levels (abbreviated dBA). Table B-1 provides A-weighted noise levels of familiar noise sources and activities.

[1] A Pascal is a unit of pressure (one Pascal is equivalent to about 0.02 lbs/ft^2). A single Pascal of pressure will produce a sound pressure level of about 94 dB.

TABLE B-1
COMMON SOURCES OF NOISE AND SUBJECTIVE HUMAN RESPONSES

Thresholds/ Noise Sources	Noise Level (dBA)	Subjective Evaluations
Human Threshold of Pain Carrier jet takeoff (50 ft)	140	Deafening
Siren (100 ft) Loud rock band	130	
Jet takeoff (200 ft) Auto horn (3 ft)	120	
Chain saw Noisy snowmobile	110	
Lawn mower (3 ft) Noisy motorcycle (50 feet)	100	Very Loud
Heavy truck (50 feet)	90	
Pneumatic drill (50 feet) Busy urban street, daytime	80	Loud
Normal automobile at 50 mph Vacuum cleaner (3 ft)	70	
Large air conditioning unit (20 feet) Conversation (3 feet)	60	Moderate
Quiet residential area Light auto traffic (100 ft)	50	
Library Quiet home	40	Faint
Soft whisper	30	
Slight rustling of leaves	20	Very Faint
Broadcasting Studio	10	
Threshold of Human Hearing	0	

Note that the subjective evaluations are continuous without true threshold boundaries. Consequently, there are overlaps among categories of response that depend on the sensitivity of the noise receivers.

Frequency Analysis

To better approximate the response of human hearing, sound level meters are often equipped with octave band filters. Octave band filters divide the audible hearing range into nine separate 'frequency-bins' much like a prism separates white-light into bands of different color or wavelengths. Imagining a piano with only nine keys to represent the full range of sound is a good analogy. Sound levels are sometimes measured using one-third octave band filters. As the name implies, one-third octave band filters further divide each octave band into three additional 'bins' for greater resolution. An analogous piano would have twenty-seven keys representing the full musical range (rather than only nine).

Percentile Levels

Environmental noise levels constantly change over time and at any given moment are often combinations of natural sounds from birds, insects or tree rustle; noise from local or distant traffic; and/or from industrial, commercial and residential activities. In order to separate low-level constant noise sources (the din of distant traffic, for example) from louder, short-duration events (such as aircraft flyovers or vehicle passbys) percentile or 'exceedance' measurements are often used. These measures help describe the 'average' noise level as well as the range of highs to lows for any given measurement period. As shown in Figure B-1:

L_{10} ('L-Ten') is the level exceeded 10% of the time, that is, levels are higher than this value only 10% of the measurement time. The L_{10} typically represents
the loudest and shortest noise events occurring in the environment, such as car
and truck pass-bys or aircraft flyovers.

L_{50} ('L-Fifty') is the sound level exceeded 50% of the time. Levels will be above and below this value exactly one-half of the measurement time, and therefore the L_{50} is sometimes referred to as the 'median' sound level.

L_{90} ('L-Ninety') is the sound level exceeded 90% of the time and is often called the 'background' sound level. Measured levels are higher than this value
most of the measurement time, so the L_{90} represents the relatively low-level, constant noise present in the environment, discernable only when temporary or varying noises such as bird calls, car pass-bys or aircraft flyovers cease.

Equivalent Energy Level

Noise levels may also be reported in terms of 'equivalent energy levels' or L_{EQ}. An L_{EQ} is a single, calculated value that is 'equal' in energy to the actual fluctuating noise for any given measurement period. As shown in Figure B-1, a noise level of 50 dBA (L_{EQ}) for a period of one minute is equivalent in energy to the fluctuating noise level for the same period produced by the car and truck passes, which range in level from less than 30 dBA to more than 60 dBA. The L_{EQ} typically falls between the L_{10} and L_{50}, and was used to quantify existing noise levels in the vicinity of the project site.

Sound Power and Sound Pressure Levels

Sound power level (PWL) is a single number that ranks how much sound energy is produced by a piece of equipment, independent of the surroundings or environment, and allows one piece of equipment to be directly compared with another. As discussed in Section 4.1, sound power levels for each major piece of equipment were used in a computer-generated acoustical model of the Project to predict property boundary and off-site noise levels.

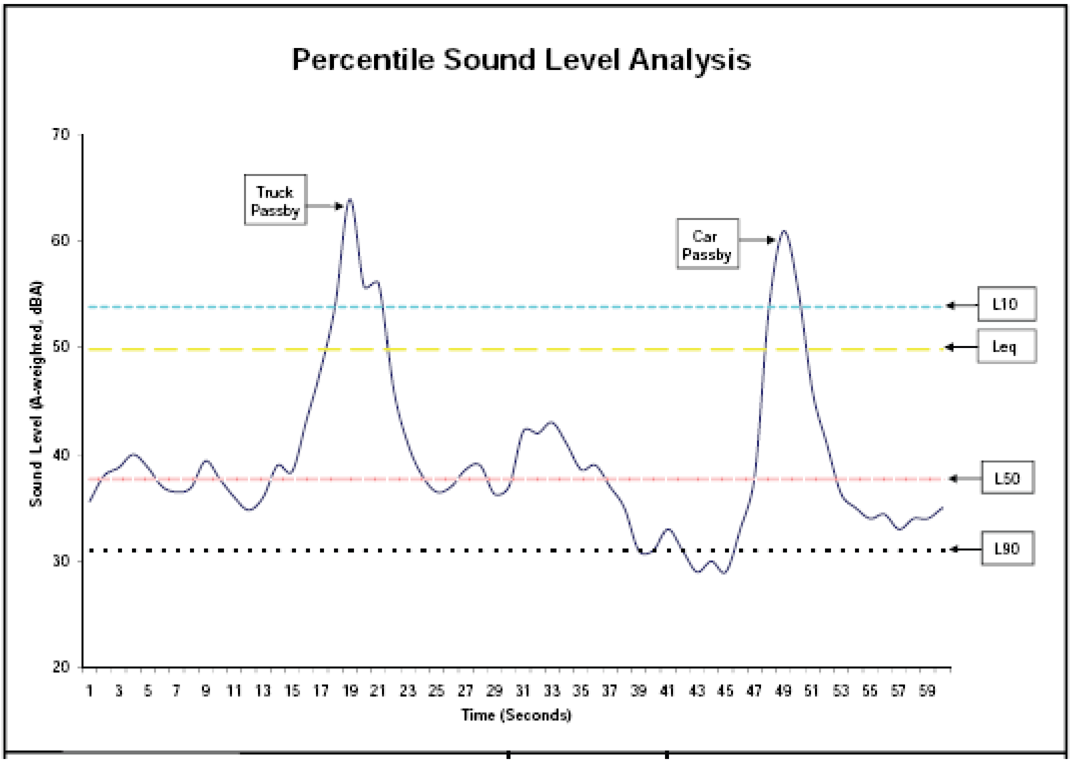


Figure B-1
Example Percentile Analysis

Sound power level is analogous to the wattage of a light bulb, whereas sound level is analogous to brightness. Sound power is *independent* of the environment; sound pressure is *dependent* on the environment. When a 75-watt light bulb is placed in a room painted white or black, it still radiates the same amount of energy. However, the apparent brightness of the light bulb changes as the room environment changes. In the room painted white, many reflections are causing the apparent brightness of the bulb to increase, and in the room painted black, much of the light is being absorbed, so the apparent brightness decreases.

For sound, a room painted white is analogous to a contemporary home with sparse furnishings and hardwood floors, i.e., little absorbing material and many reflections. A room painted black is analogous to a colonial home with rugs, overstuffed chairs, and paintings on the wall, i.e., many absorbing materials and few reflections. A blender or vacuum cleaner would tend to have a higher sound pressure level in the contemporary home versus the colonial one. Similar to light bulb wattage however, the sound power level of either appliance would remain the same regardless of the home it was placed in.

Acoustical Model

In order to evaluate expected noise levels and identify any need for mitigation measures, a three-dimensional, computer-generated acoustical model of the Project was developed using SoundPlan[7] 6.5, to predict property line and off-site noise levels, based on plan and general arrangements provided by Invenergy (see Figure B-2). SoundPlan[7] 6.5 is a computer-based acoustical analysis package specially designed for estimating noise levels from industrial facilities.

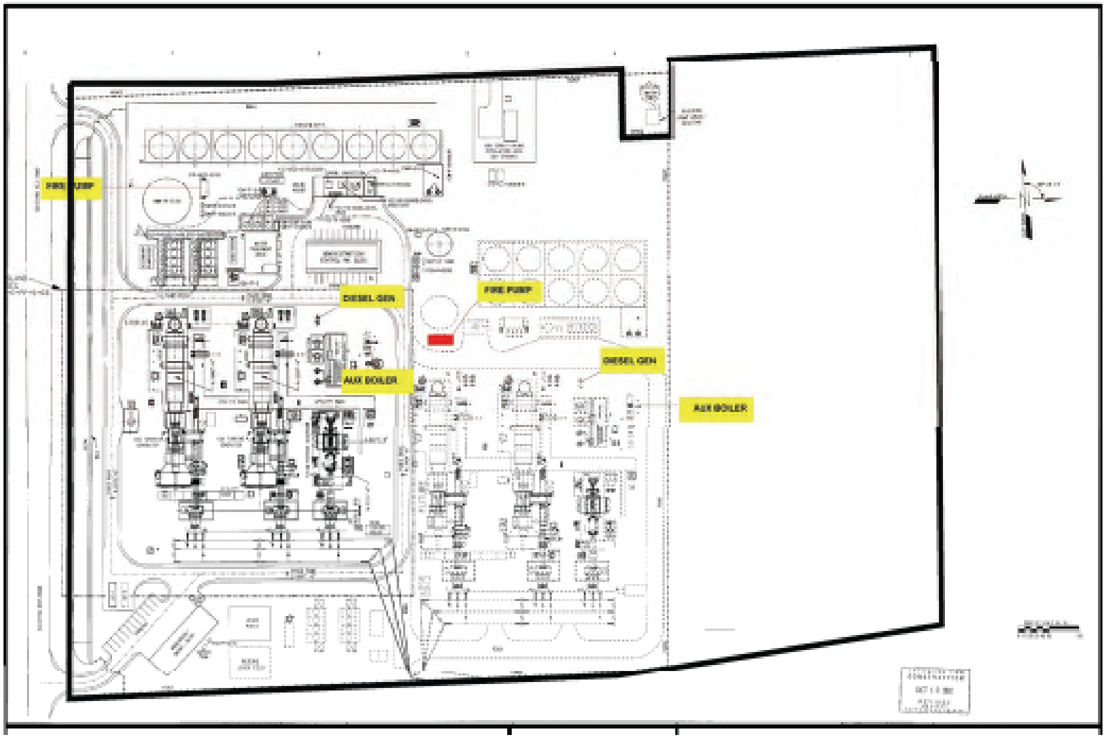


Figure B-2
Facility General Arrangement

Sound power levels (PWL) for all major noise sources (existing plus proposed equipment, including combustion turbine generators, cooling tower inlets and fans, HRSG exhausts, etc.) were estimated using octave band data from manufacturers; field-obtained data; and data from industry-standard prediction algorithms.[2]

Equipment power levels were adjusted for the reduction of sound by distance (*geometrical spreading);* the molecular absorption of sound by air (*air absorption*); and the absorption and reflection of sound by the ground (*ground effect).* Sound levels were further modified by the effects of shielding, (i.e., via tanks, buildings, equipment, etc.); and by changes in source levels with direction (*directivity)* to estimate property boundary and off-site receiver noise levels.

Acoustical Modeling Parameters

The acoustical model used for the analysis is based on ISO 9613-2, "Attenuation of Sound During Propagation Outdoors" adopted by the International Organization for

[2] Edison Electric Institute, "Electric Power Plant Environmental Noise Guide", 1978.

Standardization (ISO) in 1996. This standard provides a widely-accepted engineering method for calculating outdoor environmental noise levels from sources of known sound emission. The following sections briefly discuss the conditions under which the predictions are considered valid.

Meteorology

ISO 9613 is designed to estimate far-field noise levels under favorable sound-propagation conditions, (that is, when wind is blowing from the site towards receivers, or under well-developed temperature inversions, which commonly occur on clear, calm nights[3]). For other weather patterns, such as during upwind conditions, or for ground based temperature lapses, observed noise levels would generally be less than predicted.

Air Absorption

Absorption/attenuation of sound by air is dependent on the frequency of sound as well as on temperature and relative humidity. In general, low temperatures and low humidity increase high-frequency sound absorption, which tends to reduce far-field predicted noise levels. ‘Standard’ values were used for temperature, relative humidity, and barometric pressure, resulting in a generally conservative estimate of atmospheric attenuation.

Ground Absorption

Noise level predictions are largely dependent on both the type and extent of ground condition assumed for the site and receiver areas. Areas of ground at the Project site were modeled as ‘hard’, or completely reflective, which is typical of paving, concrete, tamped ground, water and other ground surfaces commonly found at industrial sites. Off-site ground areas were assumed to be 50% absorptive, which is characterized as semi-porous ground, and is typical of moderately vegetated land.

Reflections

For complex industrial installations with a large number of obstacles (such as buildings, tanks, equipment, etc.), reflected energy components can be considerable. Therefore, the number of reflections for the model was conservatively set at two, allowing for the effects of multiple acoustic ray paths from a single source to be considered.

---

3 Temperature inversions typically develop during calm, cloudless nights, when the ground is no longer being heated by the sun. As a result, air near the ground begins to cool, forming a thicker and thicker ‘blanket’ as the evening progresses. In practical terms, this means that temperature is ***increasing*** with elevation, (i.e., the air is actually warmer at higher elevations, as compared to near the ground) and hence the term Atemperature inversion.@ The effect of temperature inversion on sound propagation is to ‘bend’ sound waves back towards the ground, producing near worst-case sound levels at a receiver. In contrast, Atemperature lapse@ commonly develops during calm, cloudless ***daytime*** periods, when the ground is being heated by the sun, which in turn produces a warm layer of air next to the ground, as opposed to at higher elevations. This means that temperature ***decreases*** with elevation, causing sound waves to bend upwards and reducing sound levels observed at a far-field observer.

Directivity

A vertical directivity correction was used to account for changes in source levels with direction. This vertical directivity was used with sources including the HRSG stack exhausts, cooling tower fans, and gas turbine compartment ventilation fans.