BP Cherry Point Cogeneration Project

Volume 1 - Final Environmental Impact Statement
DOE/EIS-0349

Lead Agencies:

Energy Facility Site Evaluation Council

Bonneville Power Administration

Cooperating Agency:

U.S. Army Corps of Engineers

August 2004

EFSEC

Washington State Energy Facility Site Evaluation Council

BONNEVILLE
POWER ADMINISTRATION

July 12, 2004

Dear Reader:

Enclosed for your reference is the abbreviated Final Environmental Impact Statement (FEIS) for the proposed BP Cherry Point Cogeneration Project. This document is designed to correct information and further explain what was provided in the Draft Environmental Impact Statement (DEIS). The proponent, BP West Coast Products, LLC, has requested to build a 720-megawatt gas-fired combined cycle cogeneration facility in Whatcom County, Washington, and interconnect this facility into the regional power transmission grid. To integrate the new power generation into the transmission grid, Bonneville Power Administration (Bonneville) may need to rebuild 4.7 miles of an existing 230-kV transmission line.

The Energy Facility Site Evaluation Council (EFSEC or Council) and Bonneville have completed this FEIS under contract with Shapiro and Associates, Inc. The analysis was undertaken to meet the direction of the State Environmental Policy Act (SEPA) for state and private lands, and the National Environmental Policy Act (NEPA) and other relevant federal laws and regulations for federal permits and approvals.

A DEIS was issued for public comment on September 5, 2003. The public comment period closed on October 27, 2003. A public comment hearing was held on October 1, 2003, in Blaine, Washington. EFSEC and Bonneville received 33 comment letters and oral comments from 11 individuals.

The FEIS was prepared from information received from agencies, organizations, and individuals who submitted written and oral comments on the DEIS, and from testimony presented in the adjudicative hearings before EFSEC. Comments on the DEIS have resulted in changes to text and illustrations where appropriate. Volume 1, Chapter 1of this FEIS contains an updated summary and project description. Chapters 2 and 3 contain the text revisions to the DEIS. Volume 2 includes copies of written comments and public hearing testimony concerning the DEIS, and responses to those comments.

For further information regarding this proposed project, you may contact Irina Makarow at (360) 956-2047 or Tom McKinney at (503) 230-4749. For copies of the DEIS, please contact Irina Makarow at (360) 956-2047 or you may access it on the Internet at www.efsec.wa.gov.

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FACT SHEET

BP Cherry Point Cogeneration Project, Final Environmental Impact Statement (EIS) (DOE/EIS-0349)

Responsible Agencies: U.S. Department of Energy (DOE), Bonneville Power Administration (Bonneville), and Washington State Energy Facility Site Evaluation Council (EFSEC)

Cooperating Agency: U.S. Army Corps of Engineers

States Involved: Washington

Abstract: BP West Coast Products, LLC proposes to construct and operate a 720-megawatt, natural-gas-fired, combined-cycle cogeneration facility on land adjacent to its BP Cherry Point Refinery. Approximately 195 acres of undeveloped land would be converted for the cogeneration facility; gas, water, wastewater, and steam pipelines; construction laydown areas; access roads; and wetland mitigation areas.

The proposed project would be located in Whatcom County, Washington, and approximately 15 miles northwest of Bellingham and 7 miles south of Blaine. The purpose of the proposed power project is to provide stable and reliable electricity and steam to meet the needs of the refinery and provide electricity to the Bonneville Federal Columbia River Transmission System.

Electrical energy from the proposed project would require construction of a new transmission line from the switchyard in the cogeneration facility to an interconnection point on Bonneville's Custer/Intalco Transmission Line No. 2. The length of the new line would be 0.8 mile.

From the interconnection point, a 230-kilovolt (kV) circuit may be constructed to the existing Custer substation. The most reliable method of adding the new line would be replacing approximately 5 miles of the existing 230-kV single-circuit Custer/Intalco Transmission Line No. 2 with a double-circuit line. Alternatively, preliminary studies of the transmission system indicate that the circuit might not be needed if an agreement can be reached between the Applicant and the Intalco Aluminum Corporation to interrupt electrical service at the Alcoa Intalco Works under potential transmission system overload conditions. The formal agreement would be known as a Remedial Action Scheme.

This EIS assesses the existing natural and built environment, evaluates the potential environmental impacts and economic benefits of the proposed action, and identifies mitigation measures to compensate for the unavoidable impacts. Alternative project sites, power-generating and pollution-control technologies, and the No Action Alternative also are described.

Proposal's Sponsor: BP West Coast Products, LLC (Applicant)

Date of Implementation: Construction activities are expected to last approximately 25 months. The start of construction depends on the date the governor of Washington approves and signs the Site Certification Agreement for this project.

List of Possible Permits, Approvals, and Licenses: Table 2-6 of the Draft EIS lists federal and state requirements, permits, and approvals required for the proposed project, the agencies that administer the permits, and either the statute or regulation requiring the permit and approval. The EFSEC Site Certification Agreement would provide construction and operation requirements and all other relevant Washington State permits and approvals for the project. No other state or local permit is required for the proposed project.

As a federal agency, Bonneville must comply with federal permits and is precluded from participating in procedural requirements associated with state and local land use approvals or permits. The agency strives to meet or exceed the substantive standards and policies of the environmental regulations referenced above.

Authors and Principal Contributors to EIS: An independent consultant of EFSEC, Shapiro and Associates, Inc., is the principal author of the EIS. The primary source of information used to prepare the EIS is the Application for Site Certification, as amended, which was prepared by the Applicant and its primary consultants Anvil Corporation, Golder and Associates, URS Corporation, Bechtel, and Duke Energy/Fluor Daniel. A list of contributors is included in the EIS.

Subsequent Environmental Review: None anticipated.

Date of Final Lead Agency Action: After EFSEC deliberates on the facts, testimony, and EIS contents, it will send a recommendation to the governor of the state of Washington to approve or deny the project (expected in fall 2004). The governor has 60 days to accept or reject the recommendation or to remand the recommendation to EFSEC for further investigation.

Bonneville Power Administration will make a decision on the proposed interconnection no sooner than 30 days after publication of the Final EIS.

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Location of Background Information: You may access this EIS and find more information about the project and the responsible agencies on the Bonneville Web site at www.efw.bpa.gov and the EFSEC Web site at www.efsec.wa.gov. Copies of the BP Cogeneration Project Application for Site Certification, EFSEC No. 2002-01, and this EIS also are available for public review at the following locations:

Washington State Library
Joel M. Pritchard Library
Point Plaza East
6880 Capitol Blvd
Tumwater, WA, 98504-2460
360-704-5200

Energy Facility Site Evaluation Council
925 Plum Street SE, Building 4
Olympia, WA, 98504-3172
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Whatcom County Library
Attn: Kathy Richardson
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Whatcom County Library
Attn: Dave Menard
P.O. Box 1209
Ferndale, WA 98248

Bellingham Library
Attn: Gayle Helgoe
210 Central Avenue
Bellingham, WA 98225-4421

Ocean Park Library
City of Surrey
Attn: Isabelle Hay
12854 17th Avenue
Surrey, BC V4A 1T5
Canada

White Rock Public Library
Attn: Barb Hynek
15342 Buena Vista Avenue
White Rock, BC V4B 1Y6
Canada

Cost of EIS Copy to the Public: There will be no cost for the Final EIS.

For information on DOE NEPA activities, please contact Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance, EH-25, U.S. Department of Energy, 1000 Independence Avenue SW, Washington, DC 20585; by telephone at 1-800-472-2756; or visit the DOE Web site at www.eh.de.gov/nepa.

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CHAPTER 1: SUMMARY

1.1 OVERVIEW

1.1.1 Introduction

BP West Coast Products, LLC (BP or the Applicant) proposes to construct and operate a nominal 720-megawatt (MW), natural-gas-fired, combined-cycle cogeneration facility next to the existing BP Cherry Point Refinery in Whatcom County, Washington. The Applicant also owns and operates the refinery, but the cogeneration facility and the refinery would be operated as separate business units.

The cogeneration facility and its ancillary infrastructure would provide steam and 85 MW of electricity to meet the operating needs of the refinery and 635 MW of electrical power for local and regional consumption. The proposed cogeneration facility would be located between Ferndale and Blaine in northwestern Whatcom County, Washington (see Figure 1-1). The Canadian border is approximately 8 miles north of the proposed project site.

The Washington State Energy Facility Site Evaluation Council (EFSEC) has jurisdiction over the evaluation of major energy facilities including the proposed project. As such, EFSEC will recommend approval or denial of the proposed cogeneration facility to the governor of Washington after completing its review of this project.

On June 3, 2002, the Applicant filed an Application for Site Certification (ASC No. 2002-01) with EFSEC in accordance with Washington Administrative Code (WAC) 463-42. On April 22, 2003, the Applicant submitted an amended ASC that included, among other things, a change from air to water cooling.

In accordance with the State Environmental Policy Act (SEPA) and EFSEC SEPA rules (WAC 463-47), EFSEC is evaluating the siting of the proposed project and conducting an environmental review with this Environmental Impact Statement (EIS). Because the proposed project also requires federal agency approvals and permits, this EIS is intended to meet the requirements under both SEPA and the National Environmental Policy Act (NEPA). The Bonneville Power Administration (Bonneville) will use this EIS as part of its decision-making process associated with the Applicant's request to interconnect to Bonneville's transmission system. The U.S. Army Corps of Engineers (Corps) will also use this EIS as part of its decision-making process regarding the Clean Water Act Section 404 individual permit associated with the proposed location of the project within wetland areas.

The EIS addresses direct, indirect, and cumulative impacts of the proposed project, and potential mitigation measures proposed by the Applicant as well as measures recommended by responsible agencies.

Figure 1-1:

The Draft EIS for the BP Cherry Point Cogeneration Project was issued on September 5, 2003. The comment period for the Draft EIS ended on October 27, 2003. A public hearing was held on October 1, 2003 in Blaine, Washington.

During the comment period, EFSEC and Bonneville received comments from agencies, citizens, and interest groups. Comments were submitted in letters and e-mails, and given orally at the public hearing. The comments and responses are presented in Volume 2 of this Final EIS.

1.1.2 Project Changes Since Draft EIS Publication

The Final EIS updates the information that was presented in the Draft EIS. Chapters 1, 2, and 3 of this document present updates to the Draft EIS text, tables, and figures.

Refinements to the project design that have occurred since publication of the Draft EIS are summarized below.

- Revisions and design refinements have been made to certain features of the facility, including transformers, substations, water treatment facilities, pipelines, and storage tanks.
- Unresolved issues regarding construction, ownership, and operation of certain portions of the project, such as the switchyard, transmission line, natural gas supply line, and water supply line, have been decided.
- Elements of the wetland mitigation plan have been revised in response to comments from the U.S. Army Corps of Engineers.

1.1.3 Updated Environmental Information Since Draft EIS Publication

Environmental information obtained since publication of the Draft EIS is summarized below.

- Information on traffic, wildlife, aquatic resources, and seismic hazards has been refined based on testimony presented to EFSEC through the adjudicative proceeding held pursuant to Washington State statute.
- The wetland mitigation plan has been revised.
- The 404 (B) (1) alternatives analysis has been revised.

1.2 PURPOSE AND NEED FOR THE PROJECT

The proposed project has two purposes. First, it would provide the BP Cherry Point Refinery with reliable and affordable steam and electrical energy to maintain cost-effective operations. Second, it would provide electrical energy to the northwest power grid, which is needed to meet the projected growing regional demands for electricity.

1.2.1 BP Cherry Point Refinery Need

Steam is generated throughout the refinery, primarily by gas-fired utility boilers, but as a byproduct of a number of refinery processes. The more than 30-year-old boilers are used to increase or decrease steam supply volume and to maintain steam pressure as needed for various refinery operations. The proposed project could produce steam for the refinery more efficiently, cheaper, and with less emissions than the existing three utility boilers. With the proposed project, the refinery would be able to shut down the older boilers, thereby reducing air emissions from the refinery.

Two economic incentives exist for the Applicant to remove the three older refinery boilers. The first is to operate the cogeneration project at peak efficiency in cogeneration mode, thereby producing power at lower cost. The second is to use steam in the refinery that has been more cost-effectively produced by the cogeneration facility.

The cogeneration facility would be designed to operate at maximum efficiency at normal baseload conditions, which include a nominal 510,000 pounds per hour of steam being exported to the refinery. Although the steam turbine would have an operating range, it would be designed for a specific operating point for peak efficiency based on the normal expected baseload operating conditions, which include steam export to the refinery. The second incentive for the Applicant is to operate the cogeneration facility in cogeneration mode to lower the cost of producing power. Cogeneration uses waste heat more efficiently and therefore produces power using less fuel and at a lower cost than a similar facility in non-cogeneration mode.

The refinery currently produces steam for use in its petroleum product processing operations through two processes: waste heat recovery and the use of utility steam boilers. Steam produced through waste heat recovery depends on the level of refinery operation, with greater amounts of steam being produced when the refinery process unit rate is high. However, the amount of steam needed by the refinery is well in excess of the steam produced by waste heat recovery alone; the utility boilers are operated to make up the difference. The operation of the utility boilers is increased or decreased according to the overall level of operation of the refinery. The older utility boilers were installed during the refinery's original construction in 1971 and currently operate at about 83% efficiency. Economic incentive exists for the Applicant to accept as much cogeneration project steam as the refinery can use because the cost of the steam would be lower if produced at almost 100% efficiency by the cogeneration project. (One hundred percent efficiency reflects the fact that the steam is actually waste heat from the steam turbine and would otherwise need to be dissipated.) This incentive is reduced if the refinery accepts less than the cogeneration steam baseload (BP 2002).

Refinery operations require approximately 85 MW of electricity. Future facilities that create cleaner fuel products could increase this demand by about 5 MW. Historically, the refinery has relied on electricity purchased from third parties. This reliance on third-party sources has exposed the refinery to cost volatility in the electricity markets. High prices for electricity in late 2000 and early 2001 placed the viability of the refinery at risk. While the volatility has decreased significantly, the projected growth in regional power needs and the volatility in hydropower will require new power generation to balance supply and demand.

1.2.2 National and Regional Power Need

Recent national and regional forecasts predict increasing consumption of electrical energy will continue into the foreseeable future, requiring development of new generation resources to satisfy the increasing demand. The Energy Information Administration published a national forecast of electrical power through the year 2025. In it, the administration projected that total electricity demand would grow between 1.8 and 1.9% per year from 2001 through 2025. Rapid growth in electricity use for computers, office equipment, and a variety of electrical appliances in the residential and commercial sectors is only partially offset by improved efficiency in these electrical applications. Power generation from natural gas, coal, nuclear, and renewable fuels is projected to increase through 2025 to meet the growing demand for electricity and offset the projected retirement of existing generation facilities (U.S. Energy Information Administration 2003).

The Western Electricity Coordinating Council (WECC) forecasts electricity demand in the western United States. According to WECC's most recent coordination plan, the 2001-2011 summer peak demand requirement is predicted to increase at a compound rate of 2.5% per year (WECC 2002).

Based on data published by the Northwest Power and Conservation Council (NWPCC), electricity demand for its four-state Pacific Northwest planning region (Washington, Oregon, Idaho, and Montana) was 20,080 average megawatts in 2000 (NWPCC 2003).

As shown in Table 1-1, the NWPCC's recently revised 20-year demand forecast projects that electricity demand in the region will grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025 (medium forecast), an average annual growth rate of just less than 1% per year. While the NWPCC's forecast indicates that the most likely range of demand growth (between the medium-low and medium-high forecasts) is between 0.4 and 1.50% per year, the low to high forecast range used by the NWPCC recognizes that growth as low as -0.5% per year, or as high as 2.4% per year, is possible although relatively unlikely (NWPCC 2003).

Table 1-1: Projected Pacific Northwest Electricity Demand, 2000-2025

Forecast Scenario	Electricity Demand (Average Megawatts)			Growth Rates (Percent Change)	
	2000	2015	2025	2000-2015	2000-2025
Low	20,080	17,489	17,822	-0.92	-0.48
Medium Low	20,080	19,942	21,934	-0.05	0.35
Medium	20,080	22,105	25,423	0.64	0.95
Medium High	20,080	24,200	29,138	1.25	1.50
High	20,080	27,687	35,897	2.16	2.35

Source: NWPCC 2003

Generated power typically requires interconnection with a high-voltage electrical transmission system for delivery to purchasing retail utilities. Bonneville owns and operates the Federal Columbia River Transmission System (FCRTS), comprising more than three-fourths of the high-voltage transmission grid in the Pacific Northwest. Bonneville operates the FCRTS in part to integrate and transmit “electric power from existing or additional Federal or non-Federal generating units” (16 USC 838b). Interconnection with the FCRTS is essential to deliver power from many generating facilities to loads both within and outside the Pacific Northwest. The Applicant has asked to integrate power from the proposed project into the FCRTS.

In summary, electrical consumers served by the Northwest Power Pool and in other western states need increased power production to serve the predicted long-term increasing demand and high-voltage transmission lines to deliver the power.

Since the Draft EIS was published, new forecasts of energy supply and demand have been prepared. These new forecasts are discussed in Section 3.8 Energy in Volume 1, and Letter 17, Response 1(1) and Letter 23, Response 5 in Volume 2 of this Final EIS.

1.3 DECISIONS TO BE MADE

This document is a joint SEPA/NEPA Final EIS intended to meet the environmental review needs of EFSEC, Bonneville, and the Corps. EFSEC has jurisdiction over all of the evaluation and licensing steps for siting major energy facilities in the state of Washington. EFSEC’s Site Certification Agreement acts as an umbrella authorization that incorporates the requirements of all state and local laws and regulations. EFSEC will jointly issue the Final EIS with Bonneville.

EFSEC will make a recommendation to the governor of Washington to approve or deny the proposed project. Bonneville will use the Final EIS to meet NEPA requirements and will prepare a Record of Decision for the proposed project. If the governor approves the project, Bonneville will need to decide whether and how to provide transmission interconnection and service to and from the proposed project.

Bonneville intends to base its comparison of project alternatives and its final decision on the following criteria:

- Provide an adequate, economical, efficient, and reliable transmission system for the Pacific Northwest;
- Follow Bonneville’s Open Access Transmission Tariff for non-discriminatory access;
- Comply with applicable federal environmental and energy laws and policies;
- Achieve cost and administrative efficiency; and
- Minimize impacts on the natural and human environment through site selection and transmission line design.

A list of permits and requirements for the proposed project is included in Chapter 2, Table 2-6 of the Draft EIS.

The Corps will use the Final EIS, in part, to meet NEPA requirements and will prepare a Record of Decision for a Clean Water Act Section 404 permit for the proposed project. The Corps has indicated, however, that additional information on alternatives analyses and any wetland impacts associated with water pipeline improvements between the Alcoa Intalco Works facility and the cogeneration facility or upgrades to the Bonneville Custer-Intalco Transmission Line No. 2 will be required before the final Record of Decision can be completed. If the governor approves the project, the Corps will need to decide whether or not to issue the Section 404 individual permit, based in part on the impacts, proposed mitigation measures, and information contained in Appendix A of this Final EIS (Revised 404 [B] [1] Alternative Analysis) and Appendix C (Final Cogeneration Project Compensatory Mitigation Plan).

1.4 DESCRIPTION OF ALTERNATIVES

1.4.1 Proposed Action

The proposed project includes a cogeneration facility and ancillary facilities that would be located on an approximately 265-acre site. The cogeneration facility would be designed, constructed, and operated as a stand-alone facility that would have a number of systems integrated with the facilities and operations of the BP Cherry Point Refinery.

The cogeneration facility would occupy approximately 33 acres of Applicant-owned, unimproved property, which is zoned Heavy Impact Industrial. The 230-kilovolt (kV) transmission line, which would link to the Bonneville transmission line, would include approximately 15 acres of transmission right-of-way, and the proposed construction laydown areas would include an additional 36 acres of land. Wetland mitigation sites proposed for the project north of Grandview Road would occupy approximately 110 acres. Improvements to the Bonneville transmission line corridor would encompass about 71 acres.

Whatcom County Public Utility District No. 1 (PUD) would supply industrial water to the facility under a new contract between the Applicant and the PUD. Electrical transmission towers and lines from the cogeneration facility to the Bonneville electrical transmission system would be on Applicant-owned land. Natural gas would be supplied to the cogeneration facility from either the Arco Western Natural Gas Pipeline (Ferndale pipeline), which runs through Applicant-owned land. If additional gas is needed during periods of peak refinery demand, Cascade Natural Gas would provide supplemental gas to the project. The onsite stormwater detention pond would be within the boundary of the cogeneration facility. A second stormwater detention pond would be adjacent to the western boundary of Laydown Area 2. Sanitary wastewater would be sent to the refinery and then to the Birch Bay Wastewater Treatment District Plant for treatment and discharge to Birch Bay. Wastewater from the cogeneration facility would be sent to the refinery for treatment and discharge at the refinery’s Outfall 001 at the existing marine pier in the Strait of Georgia.

In this EIS, individual systems and/or components of the proposed project have been grouped into five major project elements to facilitate the analysis and discussion of potential environmental impacts associated with the proposal. The components of each major project element are briefly listed below.

Project facilities that would be constructed or installed within the boundary of the cogeneration plant are collectively referred to as the “cogeneration facility,” and include:

- A steam turbine generator;
- Three combustion gas turbine generators;
- Three heat recovery steam generators (HRSGs);
- Three HRSG exhaust stacks;
- 230-kV switchyard;
- Three 185 million volt amp (MVA) step-up transformers;
- 275-MVA step-up transformer;
- Emergency diesel generator;
- 265-hp diesel-driven emergency fire suppression water or “firewater” pump;
- Evaporative cooling tower;
- Boiler water treatment facilities;
- Various holding, storage, and transfer tanks and sumps;
- Stormwater collection, detention, and treatment facilities;
- Administration, control, and warehouse building complex;
- Perimeter security fence and gates; and
- Primary access road (Access Road 1).

Project facilities that would be constructed or installed in the BP Cherry Point Refinery to support integration and operation of the cogeneration facility are referred to as “refinery interface,” and include the following:

- Steam and condensate system connections and associated piping;
- Natural gas supply connection and associated piping;
- Natural gas compressor station;
- Industrial water supply connection and associated piping;
- Potable water supply connection and associated piping;
- Industrial wastewater connection and associated piping;
- Sanitary wastewater connection and associated piping;
- Elevated piperack assembly for supporting pipes connecting the two facilities;
- An intermediate voltage (69 kV or 115 kV) electrical distribution substation;
- Electrical distribution transformers;
- Stormwater collection, detention, and treatment facilities;
- Laydown Areas 1, 2, and 3; and
- Connecting east-west access road (Access Road 2).

A new 230-kV double circuit electrical transmission line would be installed to connect the cogeneration facility with the existing Bonneville transmission system approximately 0.8 mile to the east. Throughout the EIS, this line is referred to as the “transmission system.”

Bonneville has determined that modifications to the Custer-Intalco portion of the existing Bonneville transmission system would be required to accommodate connection of the cogeneration facility. Two options have been identified to provide the required modifications. Option 1 is to install a Remedial Action Scheme (RAS). A RAS would install additional electrical equipment within the Custer and Intalco substations, and would require an operating agreement between the Applicant, Alcoa Intalco Works, and Bonneville for load-reduction protocols to be implemented under certain conditions. Option 2 is to reconstruct the Custer-

Intalco Transmission Line No. 2 between the Custer substation and the point of interconnection with the transmission system, a distance of approximately 5 miles. Reconstruction of the transmission line would involve installation of a second transmission line and replacement of existing towers between the interconnection point and the Custer substation. Under this option, steel monopole double-circuit transmission towers would be installed (see Figure 1-2). For purposes of this EIS, the element of the project dealing with modification of the Custer-Intalco portion of the Bonneville transmission system is referred to as "Custer-Intalco Transmission Line No. 2."

Other elements of the project that would be constructed or installed in other locations as part of the project are referred to as "other project components," and include:

- Water supply connections, equipment, and piping to be installed at the Alcoa Intalco Works facility;
- Construction Laydown Area 4 (located northeast of the cogeneration facility site);
- Compensatory Mitigation Areas (CMAs) 1 and 2 (immediately north of Grandview Road); and
- A southern cogeneration facility access road (Access Road 3).

Figure 1-3 shows the relationship of project elements between the cogeneration facility, refinery, and supporting infrastructure. Chapter 2 contains a complete description of the systems and/or components of the proposed project.

Alternatives Considered but Rejected

Alternative Sites

In addition to the proposed cogeneration facility site, five other potential sites on the Applicant's property were evaluated for the facility location. They are as follows:

- East of Blaine Road and north of Brown Road adjacent to an existing cooling tower.
- Within the Cherry Point Refinery boundary fence near refinery components.
- Immediately north of Grandview Road. This area was evaluated because it contains a moderately sized upland area adjacent to Grandview Road.
- Within the refinery boundary just south of Grandview Road and west of Blaine Road. This site currently has a contractor parking lot and open areas.
- East of Blaine Road and south of Brown Road.

Locations outside refinery-owned property were not evaluated because the primary purpose of the proposed project is to supply reliable, stable, and cost-efficient electricity and steam to the refinery.

Alternative technologies and cooling systems also were considered; a list of those considered but rejected is shown below. The reasons for their rejection are described in more detail in Chapter 2.

Figure 1-2:

Figure 1-3:

Alternative Power Generation

The Applicant's evaluation of alternative power generation technologies was limited to those that could produce both steam and electricity.

- Stand-alone combined cycle
- Conventional boiler and steam turbine
- Fluidized bed combustion and steam turbine
- Other technologies such as geothermal, hydroelectric, biomass fuels, solar and wind, and coal and heavy fuel oil.
- "Refinery Load Only" Alternative

Stand-Alone Combined Cycle

This technology integrates natural-gas-burning combustion turbines and steam turbines to achieve higher efficiencies. Because of its high efficiency and superior environmental performance, combined-cycle technology is an integral part of the proposed cogeneration project. The stand-alone combined-cycle facility, however, is less efficient than a cogeneration facility and would not produce steam for use at the refinery.

Conventional Boiler and Steam Turbine

This technology burns fossil fuel (gas, oil, coal, etc.) in a conventional boiler, creating steam to drive a steam turbine generator. A fluidant such as limestone is added to the fluidized bed to capture *in-situ* sulfur oxides produced during the combustion process. Because of the relatively low thermal efficiency, high emissions, and high capital and operating costs, the Applicant eliminated the conventional boiler and steam turbine technology from consideration for the proposed project.

Fluidized Bed Combustion and Steam Turbine

Fluidized bed combustion is an alternative to the conventional boiler for creating steam, especially while burning high sulfur-bearing, difficult-to-burn fuels. Because of the environmental concerns with solid waste disposal, higher emissions, and low thermal efficiency, the Applicant eliminated the fluidized bed combustion technology from consideration.

Other Technologies

The Applicant eliminated technologies based on fuels other than natural gas because they would not have the environmental and operational advantages of natural gas. The Applicant selected natural gas technology based on its availability and the environmental and operational advantages for the proposed cogeneration project.

"Refinery Load Only" Alternative

The Applicant examined a number of alternative facility configurations for the cogeneration project, including a facility that would generate only enough electricity to meet the operating needs of the refinery (approximately 85 MW) and would therefore not require interconnection with Bonneville's power transmission facilities.

Potential facility configurations were evaluated against a set of performance requirements that the Applicant established for the project. These considerations included:

- Steam supply reliability to the refinery;
- Flexibility to accommodate larger future steam demands; and
- Economy of scale to provide suitable capital risk.

The Applicant determined that an 85-MW facility would not provide suitable steam reliability, lacked the ability to accommodate increases in future steam demand, and had a higher capital risk profile than the proposed configuration. The "Refinery Load Only" Alternative was therefore eliminated from further consideration.

<u>Alternative Cooling Systems</u>

- Dry cooling system: air cooled condenser
- Wet/dry cooling system: evaporative wet/dry cooling tower
- Wet/dry cooling: hybrid cooling system

<u>Alternative Air Emission Controls</u>

- SCONOx
- XONON

<u>Alternative Wastewater Disposal Methods</u>

- Refinery industrial wastewater treatment system
- New wastewater treatment facilities
- Zero discharge facility

<u>Alternative Electrical Interconnection</u>

- Reconductoring Custer-Intalco Transmission Line No. 2

1.4.2 No Action Alternative

Under the No Action Alternative, the proposed cogeneration facility and ancillary infrastructure would not be constructed and existing utility boilers at the refinery would remain in operation. The refinery would continue to purchase electricity, use onsite turbines to generate electrical power needed for refinery operations, or use electricity produced by other new sources of generation or through regional user-side electricity efficiency savings. If other natural-gas-fired plants were built to meet regional electric demand, they likely would not be cogeneration facilities and would produce energy less efficiently than the project. These other facilities also would likely have higher criteria pollutant and greenhouse gas emissions per kilowatt-hour than the proposed project. Finally, emission reductions associated with removal of the BP Cherry Point Refinery boilers would not be realized.

Under the No Action Alternative, the Applicant has no immediate plans to use the area proposed for the project site, but because the site is zoned Heavy Impact Industrial, it could be used for other future industrial development. Under this alternative, the impacts described for the proposed action would not occur. Approximately 110 acres of wetlands would not be enhanced, and if the Alcoa Intalco Works remained closed, the current withdrawal of approximately 2,200 gallons per minute (gpm) of water from the Nooksack River would not occur. Finally, without an additional and redundant electrical power supply, the refinery would continue to be subject to market energy prices.

The refinery's demand for both steam and electrical power is expected to grow in the future as other projects are implemented within the refinery. Although the refinery boilers would continue to operate, additional heat generation capability would be required, and this likely would be produced by new boilers and/or fired heaters.

A list of potential impacts and mitigation measures of the Proposed Action Alternative and the No Action Alternative is shown in Table 1-2.

1.5 PUBLIC INVOLVEMENT, CONSULTATION, AND COORDINATION

The Applicant has been communicating and meeting with agencies, Indian tribes, the public, and non-governmental organizations throughout development of the proposed project. EFSEC and Bonneville have conducted joint public comment and scoping meetings. The first public meeting was held on May 2, 2001 in the Blaine High School Center for the Performing Arts in Blaine, Washington. Prior to this meeting, public notices were mailed to local and regional newspapers, and press releases were issued to local and regional radio stations and newspapers. From May 2001 through 2003, meetings were held with local and state public agencies and committees, and agencies and regional committees of Canada. Formal meetings to inform stakeholders and solicit comments with these entities are listed in Chapter 2, Table 2-7. As noted above, a public comment hearing on the Draft EIS was held on October 1, 2003 in Blaine, Washington. EFSEC received additional public comment through adjudicative and land use hearings. Public comment was also received by the Corps of Engineers for a 404 Individual Permit, and by EFSEC for a 401 Water Quality Certification, a Prevention of Significant Deterioration/Notice of Construction Permit, a State Waste Discharge Permit, and a National Pollutant Discharge Elimination System Permit. Also, project documents have been available to the public on the EFSEC and Bonneville Web sites and in local libraries.

1.6 ISSUES TO BE RESOLVED

Several unresolved issues were identified in the Draft EIS. All of these issues, except for one, have been resolved, as indicated below.

1.6.1 Interconnection of the Cogeneration Project

The Applicant has asked Bonneville to provide an electrical connection with the Federal Columbia River Transmission System. The proposed point of interconnection is along one of Bonneville's existing 230-kV transmission lines between the Custer substation and Intalco substation (Custer-Intalco Transmission Line No. 2) near Brown Road. Preliminary transmission system studies indicate that to ensure reliable operation of the transmission system, integration of the project would require construction of an additional 230-kV circuit from the point of interconnection to Custer substation. The most feasible method of adding the new line appears to be replacing the existing 230-kV single-circuit Custer-Intalco Transmission Line No. 2 with a double-circuit line.

Alternatively, transmission system studies indicate that the new circuit might not be needed if agreement (a RAS) can be reached with the Alcoa Intalco Aluminum Corporation to interrupt electrical service at the Alcoa Intalco Works under certain potential transmission system overloads.

However, uncertainty remains about continuing operation of the Alcoa Intalco Works. Extended loss of load at the aluminum smelter could present other problems for operation of the transmission system. Also, there is uncertainty about whether and when other electrical generation projects planned in northwest Washington would be constructed and how that would affect transmission system operations. Bonneville continues to study how the proposed project, under this complex set of scenarios, would affect interconnected system operations.

1.6.2 Firm Transmission Service from the Cherry Point Cogeneration Project

The Applicant has asked Bonneville to provide firm, guaranteed transmission service from the point of interconnection to the Northwest Hub (Central Washington) and John Day substation. Bonneville has resolved most of the uncertainty about existing available transmission capacity to serve the Applicant's request.

1.6.3 Natural Gas Supply

The Applicant has entered into an agreement to purchase natural gas for the proposed cogeneration project. The gas would be transmitted via the existing Ferndale Pipeline to the new cogeneration facility and the refinery. If additional gas is needed during periods of peak refinery demand, Cascade Natural Gas would provide and transport supplemental gas to the project through the existing pipeline.

1.6.4 BP Refinery NPDES Permit Changes

The BP Cherry Point Refinery's existing National Pollutant Discharge Elimination System (NPDES) permit will require revision to allow the refinery to accept industrial wastewater discharge from the cogeneration facility. Ecology, the agency with jurisdiction over this permit, would address water quality issues that have been raised for the cogeneration project such as impacts of increased salinity and temperature on the herring population, the age and condition of the existing diffuser, and potential cumulative impacts on water quality through this refinery NPDES permit revision process.

1.6.5 Water Use

Letters of intent have been signed by the Applicant, Alcoa and Whatcom PUD to effectuate the contract water right purchases between the three entities that would allow the cogeneration facility to purchase water from the PUD regardless of whether the Alcoa Intalco Works aluminum smelter is operating or not. It is anticipated that agreements to purchase the contract water rights by the cogeneration facility would become final should all state and federal approvals be received.

1.6.6 Prevention of Significant Deterioration Permit and Best Available Control Technology

The Applicant's projected air emissions and selection of the Best Available Control Technology (BACT) are currently under review by EFSEC and the U.S. Environmental Protection Agency (EPA). It is anticipated that final permit requirements would be based on emission controls and BACT no less stringent than those presented in this Final EIS.

1.6.7 Change of Ownership of Cogeneration Project

The Applicant had informed the Council that TransCanada is negotiating purchase of the cogeneration project. The Applicant has addressed how change of ownership would affect the greenhouse mitigation options offered by the Applicant through a Settlement Agreement entered into with the Counsel for the Environment

1.6.8 Project Design Features

For some project components, the Draft EIS identified that additional project design and related information would be required to complete the environmental review process for the proposed project. Specific areas where additional information is required are listed below.

Since issuance of the Draft EIS, additional information was gathered regarding who would construct and operate key project components. These include:

- *230-kV switchyard*. Ownership and operation of the cogeneration facility's 230-kV electrical switchyard would be subject to the terms of a generation interconnection agreement between Bonneville and the Applicant. The cogeneration facility would own about 65% of the switchyard, and Bonneville would own about 35%. Bonneville's portion would be the part of the switchyard that allows the output of the plant to be routed to Bonneville's grid.

- *Industrial water supply*. Whatcom County PUD would construct and operate the proposed industrial water supply connection and piping required to the fenceline of the cogeneration facility. Any impacts on wetlands associated with this water supply enhancement would be addressed in a supplemental NEPA Environmental Assessment prepared for the Corps of Engineers during the permitting process.

- *Natural gas supply and compression station*. The Applicant would construct, own, and operate the cogeneration facility's natural gas supply connection, associated piping, and natural gas compression station to be located within the refinery boundary.

- *Intermediate voltage substation*. The refinery would construct and operate the intermediate voltage (230-kV to 12.5-kV) substation to be located within the refinery boundary.

Additional facility design and related descriptive information are required for some project systems and components. These include:

- *Refinery interface piping systems*. Design characteristics for a number of piping systems that interconnect the cogeneration facility with the refinery have not yet been determined. Information regarding the size, type, route, and refinery tie-in point for the following piping systems would be determined at later stages of facility design and review if the project is approved:
  - steam and condensate systems,
  - potable water supply,
  - natural gas supply,
  - industrial water supply,
  - industrial wastewater,
  - sanitary wastewater, and
  - steam and condensate pipelines, and perhaps other lines, would be carried on an elevated piperack across the utility corridor between the cogeneration facility and the refinery.

- *Custer-Intalco Transmission Line No. 2*. At this time, although general information concerning reconstruction of the Custer-Intalco Transmission Line No. 2 is available, specific design details remain to be resolved by the Applicant and Bonneville. The following summarizes information about the reconstruction and remaining uncertainties:
  - A total of 24 existing transmission line structures would be replaced during reconstruction. Approximately the same number would be needed using the monopole design (Option 2b) and slightly fewer would be needed using the lattice steel design (Option 2a). Towers for the rebuilt line would use sites at or near sites of existing towers where feasible. However, the exact number, type, and location of transmission towers that would be installed are not yet certain.

  - Existing transmission line access roads are present along the Cuter-Intalco Transmission Line No. 2 and would be used where feasible. However, whether and where roads may need improvements and whether any additional roads need to be constructed are not yet certain.
  - The need for new culverts, their size, and location are not yet certain.
- One or two temporary laydown, staging, and assembly areas would likely be required along the transmission line corridor for construction material storage and tower preparation. These areas are typically less than 2 acres in size and are usually located in existing disturbed areas such as vacant lots. However, the exact size and precise location of these areas are not yet certain.

As more specific design aspects are resolved, Bonneville would review these aspects to ensure that the environmental analysis contained in this Final EIS remains valid for describing potential impacts associated with the transmission line reconstruction and, if necessary, would prepare additional environmental documentation to ensure that all impacts are adequately considered.

1.6.9 Additional Studies/Evaluations Required to Complete the Environmental Review of the Proposed Project

404 (B) (1) Alternative Analysis. The Corps of Engineers had asked the Applicant to revise and provide more details regarding the evaluation of project alternatives. A revised 404 (B) (1) Alternatives Analysis has been completed and is included as Appendix A of this Final EIS. The Corps has indicated this document is adequate for this EIS, but additional analysis will be necessary for the Clean Water Act Section 404 permit.

1.7 SUMMARY OF POTENTIAL IMPACTS AND MITIGATION MEASURES

Table 1-2 summarizes potential impacts resulting from construction and operation of the Proposed Action Alternative and the No Action Alternative. Also included in the table are proposed mitigation measures. The Applicant, during the preliminary design of the proposed project, has mitigated potentially significant adverse impacts such that, with the exception of the permanent loss of approximately 31 acres of wetlands, no significant adverse impact on natural resources and the built environment has been identified in the environmental review. Specific impacts and mitigation measures are discussed in each section of Chapter 3 of the Draft EIS and are updated as needed in Chapter 3 of this Final EIS.

1.8 CUMULATIVE IMPACTS

The Pacific Northwest has short-term and long-term supply needs for electrical power. The WECC forecasts electricity demand in the western United States. According to WECC's most recent coordination plan, the 2001-2011 summer peak demand requirement is forecasted to increase at a compound rate of 2.5% per year (WECC 2002).

The NWPCC regularly prepares a 20-year forecast of electricity demand in the Pacific Northwest. NWPCC's latest long-term forecast found that the total consumption of electricity is forecasted to grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025, an average yearly rate of growth of just under 1% (NWPCC 2003).

In addition to evaluating the environmental impacts of proposed power projects on an individual basis, EFSEC and Bonneville have also considered potential cumulative impacts of these projects, as well as other projects and actions that could contribute to cumulative impacts. This concern of the state and federal agencies is magnified when several projects are proposed at the time in the same vicinity with schedules that overlap.

The following is a summary of the cumulative impact evaluation included in this EIS.

1.8.1 Global Warming

Most greenhouse gas emissions that would result from the construction and operation of this project would be in the form of carbon dioxide (CO_2), with a smaller fraction of methane or nitrous oxide. The contribution of greenhouse gas from this project would represent 2.5% of the greenhouse gas emitted from all sources in Washington State and 0.03% of U.S. emissions. Although it is possible to predict global warming effects in the Pacific Northwest due to overall increases in greenhouse gas concentrations in the atmosphere, it is not possible to determine the specific impact on a regional or global scale resulting from the BP Cherry Point Cogeneration Project greenhouse gas emissions alone. Regional economic growth and the subsequent increases in greenhouse gas emissions, including those from additional gas-fired generation, would also add to the cumulative impacts.

1.8.2 Regional Air Quality

The results of modeling under the worst-case scenario for criteria pollutants from the proposed project indicate there would be no air quality impacts in the US or Canada when compared to the most stringent values of the National Ambient Air Quality Standards, Washington Ambient Air Quality Standards, or Canadian Objectives or Standards. The Applicant has committed to shut down three older utility boilers, resulting in overall reductions of PM_{10} and NO_x emissions in the airshed. Construction of the Georgia Strait Pipeline along Grandview Road at approximately the same time as construction of the proposed project would only temporarily affect air quality through the emission of fugitive dust.

1.8.3 Water

With the construction of the proposed project and the Georgia Strait Pipeline project scheduled at around the same time, there is a possibility of cumulative impacts. These impacts could potentially result from the use of water to control dust, pipeline testing and cleaning, and hydrotesting major pipelines.

Other known or proposed projects in the Terrell Creek watershed include the GSX pipeline, the BP ISOM unit, and the Brown Road Materials Storage Area. The GSX pipeline traverses about 5 miles of Terrell Creek watershed. While some wetlands would be excavated, they would be reestablished after construction to restore their hydrologic character. The pump station would be on a 5-acre site, but none of that would be wetland. The ISOM unit would be constructed on existing impervious surface at the refinery where stormwater treatment and detention are already provided. The Brown Road Materials Storage Area would eliminate about 11 acres of wetlands that provide surface water storage but would include 34 acres of wetland mitigation to replace that function. With the cogeneration project, there would be 30.5 acres of wetlands lost and 110.1 acres of wetland mitigation. Cumulatively, there would be some incremental loss of wetland surface water storage in the watershed, but that would be offset by onsite treatment and detention, and offsite mitigation in the basin.

With the shutdown of the Alcoa Intalco Works, water used at that facility would now be used by the proposed project, so there would be no net increase of water consumption when the proposed project becomes operational. If Alcoa Intalco Works operates at the same time as the cogeneration facility, there still would be no cumulative impacts because the once-through cooling water from Alcoa Intalco Works would be used by the cogeneration facility, thereby precluding the need for additional withdrawal of water from the Nooksack River.

Several industrial dischargers are located in the general vicinity of the proposed cogeneration project. These include the BP Cherry Point Refinery, the Conoco-Phillips Refinery, Tenaska Washington Cogeneration Power Plant, and Alcoa Intalco Works. All of these facilities currently discharge to the Strait of Georgia. Also, the Birch Bay Sewer District Treatment Plant discharges to Birch Bay, an embayment of the Strait of Georgia. Although discharge from the proposed project would represent a relatively small increase to the regional discharge to the Strait of Georgia, it adds to the overall burden on water quality.

1.8.4 Natural Gas Supply

The projected annual consumption of natural gas by the proposed project is approximately 42,457,000 million British thermal units (MBtu). The proposed project would result in an incremental contribution to the regional demand for natural gas. However, there is sufficient capacity in the gas supply and distribution system serving the Pacific Northwest to supply the proposed cogeneration project and existing and planned natural-gas-related projects such that the overall effect on available supplies would be negligible.

1.8.5 Transmission Lines

Construction of the cogeneration facility’s transmission line and the possible reconstruction of the Custer-Intalco Transmission Line No. 2 would not have a cumulative impact on the natural resources within western Whatcom County. The short 0.8-mile cogeneration transmission line would connect the project to Bonneville’s existing transmission system. The Bonneville line would not need to be extended and, except for the 230-kV switchyard at the cogeneration facility, no new substations would need to be constructed as a result of the proposed project. Bonneville is continually conducting studies to determine the need to extend their transmission system.

1.8.6 Transportation

Construction of the proposed project and the construction of the Georgia Strait Pipeline project would occur at about the same time. It is expected that some increased traffic congestion and delays at intersections along Grandview Road would occur over the two-year period. Based on traffic modeling completed for the proposed project, the results indicate that the level-of-service at all major regional intersections would operate at acceptable levels as defined by Washington State Department of Transportation design standards.

1.8.7 Population, Housing, and Economics

A workforce analysis conducted by the Applicant suggests that there is an adequate labor pool available for construction of the proposed project. If additional projects, such as the Georgia Strait Pipeline project, were to be constructed within the region, some workers likely would relocate to the area, temporarily affecting the local housing market, population, and local services. This potential future condition is not expected to be a significant cumulative impact on communities in the project vicinity.

Table 1-2: Summary of Impacts and Mitigation Measures

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Earth			
Construction	• Extensive grading of the site is not anticipated to be required, however some unsuitable materials may require removal from the site for disposal at approved locations. • The total quantity of imported fill material is estimated to be approximately 126,000 cubic yards (75,600 tons). • Site grading and stockpiling activities would expose soils and would increase the potential for erosion. • The potential exists for contacting contaminated soils during excavation activities at the BP Cherry Point Refinery and at the Alcoa Intalco Works facilities because of industrial practices that have occurred at these sites since the 1970s.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any construction impacts for this element of the environment.	<u>Mitigation Proposed by the Applicant</u> • Best Management Practices (BMPs) would be implemented for erosion control and prevention. The BMPs would be described in a Stormwater Pollution Prevention (SWPP) plan and Temporary Erosion and Sedimentation Control (TESC) plan to be submitted to EFSEC prior to construction. • If soil contamination were found during site clearing, grading, and trenching, the activities would be halted until the contamination can be identified and contaminated soils handled in the appropriate manner. • Excavated materials of acceptable quality would be reused as much as possible. • Excess materials would be disposed of at permitted fill sites or would be placed where they would not easily erode. • Disturbed areas would be revegetated by seeding or hydroseeding. • Seed mixes would be selected that are known to effectively stabilize erodible soils in the northwestern portion of the State of Washington. • Soil stockpiles would be seeded or covered with an emulsion and surrounded by silt fences and straw bales or sand bags, where necessary, to prevent excessive erosion by wind or rain. • Sprinkler systems may be employed to sustain vegetation on bermed areas with high exposure to the erosive forces of wind. • Erosion control measures for construction, such as silt fencing, straw bales, and tarps, would be inspected and maintained. • A Spill Prevention Control and Countermeasure (SPCC) Plan would be prepared. The plan would include procedures to implement structural, operational, and treatment BMPs.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			• Stormwater runoff from the construction site would be collected and routed to a sediment control system. • Sediment control measures, such as an oil-water separation system and detention ponds, would be sized for storm events ranging from 6-month, 24-hour up to the 100-year, 24-hour event.
Operation	• During operation, there would be the potential for a large seismic event to impact cogeneration facility operations (i.e., the production of electricity). • During operation, the greatest risk to the project from volcanic activity would be from tephra (ash) fall.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any operation impacts for this element of the environment.	Mitigation Proposed by Applicant • The characteristics of the soils would be determined during the geotechnical analysis completed during detailed project design. If the soils prove to be susceptible to induced amplification, the project design would incorporate protection measures against such seismic events.
Air Quality			
Construction	• Emissions during the construction process would consist of fugitive dust and combustion exhaust emissions from construction equipment and vehicles. It is not anticipated that these emissions would exceed the NAAQS or WAAQS.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any construction impacts for this element of the environment.	Mitigation Proposed by the Applicant • Roads would be covered with gravel to minimize the potential for fugitive dust emissions from vehicle traffic. • Late in construction, gravel roads would be paved to further reduce emission of fugitive dust. • Spraying exposed soil with water would reduce PM_{10} emissions and particulate matter deposition. • Planting vegetative cover as soon as appropriate after grading would reduce windblown particulate matter in the area. • Use appropriate dust control measures to minimize windblown dust from transportation of materials by truck, which may include wetting and covering. • Use appropriate measures to reduce particulate matter from wheels before entering roads, which nay include wheel washers. • Routing and scheduling construction trucks so as to reduce delays to traffic during peak travel times would reduce secondary air quality impacts caused by a reduction in traffic speeds while waiting for construction trucks.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			• Maintain construction equipment in good working order to reduce CO and NOx emissions.
Operation	• During operation, emissions from the cogeneration facility would include SO_2, PM_{10}, $PM_{2.5}$, VOCs, CO, and NO_2, however all pollutant concentration levels would be well below National Ambient Air Quality Standards or Washington Ambient Air Quality Standards. • Emissions of toxic air pollutants would result from the combustion of natural gas in the cogeneration facility, however, modeled maximum concentrations are less than the state's Acceptable Source Impact Levels. • The cogeneration facility would provide steam to the refinery and allow existing refinery boilers to be shut down, thereby providing an offsetting air quality benefit. • Cogeneration emissions are projected to contribute to a decrease in visibility at the Olympic National Park. • Fogging from the cooling tower vapor plume may occur for 650 to 1,650 feet for a total of 2.5 hours a year in the northeast or northwest directions from the tower.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any operation impacts for this element of the environment. Existing less efficient refinery boilers would continue to be operated. Less efficient fossil fuel combustion technologies, which may be added to fill long term regional power needs, would likely produce more air emissions per KW-hr produced.	<u>Mitigation Proposed by the Applicant</u> • Only natural gas would be burned in the combustion turbines and duct burners, and only low-sulfur diesel fuel in the emergency generator and firewater pump. • BACT would be used at the cogeneration facility. BACT to control criteria pollutant emissions include: - Dry low NO_x combustion technology; - Selective catalytic reduction technology; - Oxidation catalyst controls incorporated into the HRSGs to reduce CO emissions and VOCs. • BACT to control toxic emissions include: - Use of clean natural gas as the only fuel for the combustion gas turbines and HRSG duct burners; and - Use of oxidation catalyst unit on each HRSG duct burner. • As long as the Applicant owns the cogeneration facility, mitigation of greenhouse gases (GHG) would be offset by GHG reduction within BP West Coast Products, LLC worldwide operations. • If the ownership of the cogeneration facility is transferred to another party, then mitigation of GHG emissions would be provided by: - The proposed CO_2 emission standard would be 0.675 lbs. CO_2/kWh, - Emissions in excess of the emission standard would be mitigated either by (a) an annual payment of \$0.85/ton CO_2, or (b) GHG reductions obtained by the new owner, or (c) a combination of both. - Mitigation would be satisfied annually for 30 years.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			- If BP retains partial equity in the facility, it would continue to offset the associated portion of GHG emissions from the project. - Startup and shutdown procedures would be followed as developed by manufacturers and documented in the Applicant's Startup, Shutdown and Malfunction Procedures Manual. - Existing refinery boilers would be removed within six months of commercial operation.
Water Resources			

Construction	• Water from various sources would be used to support construction, including:
	  • Approximately 7 million gallons of trucked water from the refinery would be used for dust control; and
	  • Approximately 21.5 million gallons of fresh water from the public utility district would be used for steam blow testing and hydrostatic testing.
	• Stormwater flow would be altered to control erosion and sedimentation during construction
	• Groundwater recharge would be reduced under the project site during construction, but would increase in the wetlands north of Grandview Road.
		• Under the No Action Alternative, the project including proposed wetland mitigation areas would not be constructed. Therefore, there would not be any construction impacts for this element of the environment.	<u>Mitigation Proposed by the Applicant</u>
			
			• Stormwater would be collected, treated, and discharged off-site within the same drainage basin allowing groundwater recharge in the same hydrological system.
			• A Stormwater Pollution Prevention (SWPP) plan would be developed prior to construction, the SWPP plan would include Temporary Erosion and Sedimentation Control (TESC) plans.
			• The SWPP and TESC would specify Best Management Practices for erosion control during construction. All erosion control BMPs would be in place and functioning prior to construction.
			• Stormwater runoff from project site roads and other impervious areas would be collected in an oil-water separator to draw off any trace oil and then route the stormwater to a detention pond to allow sediment to settle out.
			• Stormwater collected from the construction site would be routed to an unlined surface detention pond and allowed to infiltrate or discharge to wetlands within the same hydrologic basin. The net effect would be returning the collected stormwater to the same hydrologic system for recharge.
			• Stormwater runoff from around the site would be continue to be routed to existing ditch along the Blaine Road and then discharged to Terrell Creek.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			• Diversion ditches would prevent surface water runoff from areas outside the cogeneration site from entering the site. • The Applicant would not construct a perimeter ditch along the west side of Wetland C. • Stormwater runoff from within the cogeneration site will be contained, collected, and routed to the stormwater treatment and detention system.
Operation	• During operation, the cogeneration facility would use between 2,244 and 2,316 gpm of process water for cooling and other facility functions. The water would either be recycled cooling water from the Alcoa Intalco Works aluminum smelter if that facility is in operation, or water received directly from the PUD if the Alcoa Intalco facility is not in operation. • The cogeneration facility would use between 1 and 5 gpm of potable water supplied by the Birch Bay Water and Sewer District. • During operation, the cogeneration facility would generate industrial wastewater from: - Treatment of raw water to produce high quality boiler feedwater (BFW) and refinery return condensate treatment; - Collection of water and/or other minor drainage from various types of equipment; - Cooling tower blowdown; and - Sanitary waste collection. • Runoff from surfaces containing contaminants could impact surface and groundwater. • Groundwater recharge impacts would be the same as for construction.	• Under the No Action Alternative, the project including proposed wetland mitigation areas would not be constructed, therefore there would not be any operation impacts for this element of the environment.	<u>Mitigation Proposed by the Applicant</u> • Wastewater would not discharge directly into any watercourses (including creeks, lakes, wetlands, ditches, or the marine environment), or storm drains, nor will it require any new outfalls. • Stormwater runoff quantities would be controlled by the stormwater collection and treatment system. • Stormwater collected from the cogeneration site would be routed to an unlined surface detention pond and allowed to infiltrate or discharge to wetlands within the same hydrologic basin. The net effect would be returning the collected stormwater to the same hydrologic system for recharge. • The SWPP plan for operation would include structural and operational BMPs, a Spill Prevention, Control and Countermeasure (SPCC) plan, a final stormwater management plan, and general operating procedures. • Industrial wastewater would be treated in the refinery's wastewater treatment system prior to discharge to the Strait of Georgia.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
	• During operation of the project, surface water from the cogeneration facility would be discharged to the CMA 2 site, increasing flows to the site. Increased flows the site, combined with topological modifications proposed for the site, is expected to increase hydraulic residence time on the site, thus enhancing existing wetlands and restoring wetlands that have been effectively drained.		• Sanitary wastewater would be routed to the Birch Bay Sewer District's wastewater treatment plant for treatment and discharge to the Strait of Georgia.
Water Quality			
Construction	• Wastewater containing contaminants would be generated during plant construction and pre-operation testing. • During construction of the project, potential water quality impacts could be caused by: - Sediment-laden stormwater discharged from the project site during construction; and - Spills and leaks of chemicals, especially a large volume spill, during construction could impact stormwater, surface water (wetlands), and groundwater. • Water used for HRSG steam-blow tests would be discharged as steam to the atmosphere. If contaminants are present in the water, the contaminants may be discharged to the atmosphere with the steam. • Runoff from surfaces containing contaminants could impact surface and groundwater. • Sanitary waste generation is anticipated to be 500 gallons per day during construction of the project.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any construction impacts for this element of the environment.	Mitigation Proposed by the Applicant • Hydrostatic test water would be discharged to the refinery's wastewater treatment system and then discharged to the Strait of Georgia. If hydrostatic test water does not meet the water discharge quality, other offsite disposal options would be necessary. • SWPP plan for construction activities would be prepared for the various elements of the project, and would include stormwater management procedures, Temporary Erosion and Sedimentation Control (TESC) plan for each phase of project, the specification of all necessary BMPs for construction activities as specified in the Stormwater Management Manual for Western Washington (Ecology 2001), and include general operation and maintenance descriptions of the BMPs used on site. • All erosion control BMPs would be in place and functioning prior to the start of construction. • To minimize the potential release or spills of chemicals during construction, best management practices, as specified in the SWPP plans, would be employed. These would include good housekeeping measures, inspections, containment facilities, minimum onsite inventory, and spill prevention practices.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			Additional Mitigation Measures • If project approval is recommended, EFSEC would develop State Waste Discharge and National Pollutant Discharge Elimination System Permit conditions for construction of the cogeneration facility. The permit would specify construction stormwater effluent limits and monitoring requirements intended to reduce or eliminate water quality impacts. Monitoring of stormwater would commence at the beginning of construction.
Operation	• Spills and leaks of chemicals, especially a large volume spill, during operation could affect stormwater, surface water (wetlands), and groundwater. • The cogeneration facility would produce 190 gpm on average (assuming 15 cycles of concentration in the cooling tower) of non-recyclable process wastewater which would be sent to the BP refinery's wastewater treatment system. • Between 1 and 5 gpm of sanitary waste would be generated by the cogeneration facility. • Periodic washing of the gas turbines would generate up to approximately 2,300 gallons of wash water per turbine per quarter. The wash water would likely contain dirt deposits removed from the blades, along with detergents used for the cleaning operation. • Operation and maintenance of the industrial water supply pipeline and associated components at the Alcoa Intalco Works could result in potential erosion/sedimentation and chemical spills that could impact surface water and groundwater quality.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any operation impacts for this element of the environment.	Mitigation Proposed by the Applicant • SWPP plan for operational activities would be prepared for the cogeneration facility, and would include stormwater management procedures. The SWPP plan for operation would include structural and operational BMPs; a SPCC plan; and a final stormwater management plan. • Prior to operation of the cogeneration facility, a SPCC plan would be prepared the plan would contain procedures for spill response, containment, and prevention procedures; and structural, operational, and treatment BMPs. • Safeguards incorporated to mitigate the risks of a release to the environment from stored operational chemicals include secondary containment, tank overfill protection, routine maintenance, safe handling practices, supervision of all loading/unloading by plant personnel and truck drivers, and appropriate training of operation and maintenance staff. • Industrial wastewater from the cogeneration facility would be treated in the refinery's wastewater treatment system prior to discharge to the Strait of Georgia. • Sanitary wastewater would be routed to the Birch Bay wastewater treatment plant for treatment and discharge to the Strait of Georgia.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			Additional Mitigation Measures • If project approval is recommended, EFSEC would develop State Waste Discharge and National Pollutant Discharge Elimination System Permit conditions for operation of the Cogeneration Facility. Permit conditions would include discharge limitations, monitoring requirements, reporting and record keeping requirements, operation and maintenance plan for water quality treatment facilities, development of SPCC and hazardous waste management plans, and SWPP plan.
Wetlands			
Construction	• Construction of the project would disturb 35.52 acres of existing wetland areas, including 30.66 acres that would be permanently disturbed and 4.86 acres that would be temporarily disturbed. Affected wetlands would be located at the cogeneration facility site (Wetlands A, B1, B2, B3, C, and D), the refinery interface (Wetlands F, G, J, and H), and the transmission system. • Reduced wetland functions would include floodwater detention and retention, flood flow desynchronization, groundwater recharge and discharge, and water quality improvement.	• Under the No Action Alternative, the project including proposed wetland mitigation, would not be constructed. Therefore no construction impacts or wetland enhancement would occur.	Mitigation Proposed by the Applicant • Mitigation measures consistent with those generally required by the Corps and Ecology for Category III wetlands within Western Washington would be implemented during construction to protect wetlands that would not be filled. Wetlands not disturbed would be protected using silt fencing and haybales. Wetlands temporarily disturbed and would be restored after the project construction is completed. • To compensate permanently disturbed wetlands the Applicant has designed a compensatory mitigation plan in consultation with state, and federal agencies. The proposed plan outlines the enhancement of 110 acres north of Grandview Road. • To minimize and control the spread of noxious weed species, all equipment would be cleaned before leaving the site.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Operation	• Other than those communities affected by construction, operation of the project would not affect existing wetland systems.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any impacts for this element of the environment. The proposed wetland enhancement and the creation of new wetlands would not occur.	Mitigation Proposed by the Applicant • A 10-year monitoring plan would be implemented to measure mitigation success.
Agricultural Land, Crops, and Livestock			
Construction	• The proposed project elements would result in the development or modification of land that Whatcom County has identified as Category I and II prime farmland soils and mapped as APO soils and Agricultural Open Space. • Reconstruction of Custer/ Intalco Transmission Line No. 2 would likely result in the conversion of some prime farmland to utility uses within the existing Bonneville Transmission Corridor. • Construction of the cogeneration facility, Access Road 1, and Laydown Areas 2 and 4 would result in a direct and permanent loss of approximately 2.6 acres of existing hybrid black cottonwood. • The proposed compensatory wetland mitigation plan would preclude the continued use of mitigation area CMA 1 for cattle grazing.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any impacts for this element of the construction environment.	Mitigation Proposed by the Applicant • No mitigation measures for agricultural land, crops, and livestock are proposed.
Operation	• Emissions from the cogeneration facility are expected to have a negligible effect on agricultural crops and livestock.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any impacts for this element of the operation environment.	• No operational mitigation measures for agricultural land, crops, and livestock are proposed.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Upland Vegetation, Wildlife and Habitat, Fisheries, and Threatened and Endangered Species			
Construction	• Construction of the project would disturb up to 33.53 acres of existing upland vegetation, including: including grassland, shrubland, mixed coniferous/deciduous forest, coniferous forest, and deciduous forest. While adding a transmission line from Brown Road to Custer Substation would involve rebuilding an existing line in a right-of-way already cleared of tall-growing vegetation, some additional removal of individual trees potentially interfering with the rebuilt line may need to be removed in limited wooded areas for a total of about one mile along the five-mile long corridor. • The primary effect from project construction would be removal and loss of habitat. Grassland and wetland communities are the primary habitats that would be cleared under the proposed alternative. Other habitats that would be cleared include shrubland, mixed coniferous/deciduous forest, coniferous forest, and deciduous forest. • Disturbances caused by construction on the site may affect wildlife in adjacent habitats by disrupting feeding and nesting activities. Increased noise levels created by heavy machinery could cause birds to abandon their nests and may temporarily displace wildlife during construction. • Proposed wetland enhancement and the creation of new wetlands associated with proposed wetland mitigation sites CMA 1 and CMA 2 would result in an increase in habitat quality, would benefit wildlife species that currently use the area, and would likely attract a more diverse assortment of wildlife species.	• Under the No Action Alternative, new facilities would not be constructed at the site, and impacts on upland vegetation, wildlife and habitat, fisheries, and threatened and endangered species associated with the proposed project would not occur. No impacts or construction would occur that would entail removal or alteration of existing habitat within the proposed project site. • The proposed wetland enhancement and the creation of new wetlands associated with proposed wetland mitigation sites CMA 1 and CMA 2 would not occur.	<u>Mitigation Proposed by the Applicant</u> • BMPs would be implemented to protect upland vegetation communities within the proposed project site that are not disturbed during construction. • Native vegetation, including seed mixes with native grasses, would be used to replace vegetation, particularly areas infested by weedy species. • A landscaping plan would be prepared and implemented that includes long-term weed control measures. • Plant native trees and shrubs parallel to the south side of Grandview Road, north of the cogeneration facility site and north of the laydown areas, to the west of Blaine Road. • Development of the stormwater control system would maintain water quality and fishery resources in Terrell Creek • Development and implementation of the SWPP plan would also protect water quality and fishery resources. • Mitigation requirements as conditions of permits or government approvals would be implemented. • Construction Laydown Area 4 would be restored following construction. • The Applicant would restore, rehabilitate and enhance wetlands north of Grandview Road, identified as mitigation sites CMA 1 and CMA 2. • In accordance with the Settlement Agreement between the Applicant and Whatcom County regarding the protection of herons, earthwork activity to create the wetland mitigation sites CMA 1 and CMA 2 has been scheduled for the dry season, which coincides with the end of the fledging period, and most plantings would occur in the fall and winter when the herons are dispersed.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Operation	• Some areas currently dominated by noxious weed species may be converted to landscaped areas that would require maintenance. The establishment of noxious weed species may occur within the proposed plant site. • Operation and maintenance associated with the transmission corridors would include removing or topping trees to maintain a safe distance between trees and electrical lines. • Existing access and maintenance roads associated with transmission corridors would be maintained to prevent vegetation from growing in these areas. Vegetation that becomes established in disturbed areas such as unpaved roads are often nonnative invasive species. • Some wildlife habitat loss, noise, and disturbance could occur during maintenance activities within the transmission corridors. • Maintenance and operation activities associated with the transmission corridors could result in chemical spills that potentially could impact fish habitat.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any impacts for this element of the environment.	• Implement noxious weed control program pursuant to wetlands mitigation requirements, and maintain landscaped areas to prevent spread of noxious weeds. • The primary mitigation measure applicable to the proposed project is to use best engineering practices and construct the transmission towers at the minimal height allowable with no guy wires or lighting to avoid impacts on birds. The transmission lines and tower design would be defined by the Bonneville interconnection agreement. • See also Air Quality, Water Resources, and Water Quality. • The Applicant plans to maintain at least 23 acres of the wetland mitigation site (CMA 2) in open field habitat. In addition, wetland mitigation design includes improving the quality of heron habitat for heron foraging, maintaining connectivity to other existing forage areas, and enhancing areas to promote amphibian breeding habitats.
Energy and Natural Resources			
Construction	• Construction of the cogeneration facility would consume non-renewable resources, including: - 126,000 cubic yards of imported fill - 7,500 cubic yards of sand - 18,150 cubic yards of gravel - 25,200 cubic yards of concrete - 1,050 tons of steel • Construction of the cogeneration facility would consume electrical energy for lighting and heating in construction offices, temporary lighting at the facility, and powering various pieces of construction equipment. The estimated peak electrical demand during construction is approximately 2.5 MVA at 480 V. • Construction of the cogeneration facility would consume approximately 592,000 gallons of petroleum products, including diesel fuel and gasoline.	• Under the No Action Alternative, the cogeneration facility would not be constructed and the consumption of energy or natural resources associated with construction of the project would not occur.	<u>Mitigation Proposed by the Applicant</u> • Conservation of energy and natural resources during construction would take place through the use of industry standard BMPs. These may include the use of energy-efficient lighting, lighting of only critical areas during non-working hours, encouraging car-pooling, efficient scheduling of construction crews, minimizing idling of construction equipment, recycling of used motor oils and hydraulic fluids, and implementation of signage to remind construction workers to conserve energy and other resources.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Operation	• During operation, the cogeneration facility would consume approximately 42.5 million MBtu of natural gas per year. • The proposed project may exceed the transmission capacity of the Ferndale Pipeline during periods of peak demand. The Applicant estimates that up to approximately 40,000 decatherms per day of additional capacity of may be needed. • Operation of the cogeneration facility would consume petroleum products, primarily lubricants associated with the operation of equipment and gas and diesel fuel for vehicles around the facility • The cogeneration facility would use various chemicals during operation to facilitate desired chemical reactions, control water quality, and for other facility operational purposes. • Transmission line maintenance would require relatively small quantities of fuel for vehicles and helicopters engaged in transmission line surveillance and monitoring, and electricity to maintain and operate equipment at Custer Substation. Transmission corridor road maintenance would require the use of crushed rock, gravel, and sand during the life of the project on an as-needed basis. Periodic replacement of conductor wires, ground wires, fiber optic cables, insulators, and structural elements may be required over time. • Generate a nominal 720 MW of electricity, of which, approximately 85 MW would be used by the BP Cherry Point Refinery, 21 MW would be used by the natural gas compression station and other cogeneration facility auxiliary systems, and 635 MW would be exported to the Northwest power grid for use by other customers. • Supply approximately 4,200 million pounds (MMlb) of steam per year to the refinery.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any construction impacts for this element of the environment. • Under the No Action Alternative, the Applicant would likely continue to meet the electrical power needs of the refinery with a combination of onsite electrical power generation and purchasing electrical power from other sources. The existing refinery boiler system would continue to be used to meet the refinery's steam demand. Under this alternative, the cogeneration facility would not generate and transmit electrical power for use on the Northwest power grid.	<u>Mitigation Proposed by the Applicant</u> • Boiler blowdown water would be routed to the cooling tower as make up water to reduce fresh water consumption. • Existing utility boilers would be taken out of service and replaced with more efficient cogeneration steam generation cycle, reducing the use of natural gas resources. • Construction activities would be coordinated with energy and natural resource providers to ensure that other users in the area would not experience any service interruptions.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Noise			
Construction	• Noise produced during construction would vary depending on the construction phase underway. Maximum noise levels from most construction equipment could range from 69 to 106 decibels or dB(A) at 50 feet. • In addition to noise produced from onsite construction equipment, traffic volumes would increase as construction employees commute to and from work at the site. Additional transient noise would occur as a result of increased volumes of delivery and service vehicles (including trucks of various sizes) doing business at the site.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any construction or traffic noise impacts.	<u>Mitigation Proposed by Applicant</u> • To reduce construction noise, the construction industry's management practices would be incorporated into construction plans and contractor specifications. • Limiting noisier construction activities to the hours of 7 a.m. and 10 p.m. would reduce construction noise during sensitive nighttime hours. • Construction equipment would be equipped with adequate mufflers, intake silencers, or engine enclosures. • Turn off construction equipment during prolonged periods of nonuse. • Require contractors to maintain all equipment. • Locate stationary equipment away from receiving properties.
Operation	• Modeling results indicate that none of the receivers would experience a perceptible increase (above 3 dBA) in noise during the daytime or evening.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any operational or equipment impacts.	<u>Mitigation Measures Proposed by the Applicant</u> • The cogeneration placement and design of the facility has integrated noise mitigation measures for sound reduction. • Stack silencers would be incorporated into the design of the HRSG. • The three gas turbine generators and the steam turbine generator will be housed within enclosures. • Operation of the cogeneration facility would comply with regulations governing noise from industrial facilities (WAC 173-60). • In accordance with the Settlement Agreement with Whatcom County, the Applicant would limit noise-generating activities such that noise levels at five regional receptors would not exceed existing levels.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
			• Within 180 days of the beginning of operation, the Applicant would conduct post-operation noise monitoring at the five receptors to determine compliance with the noise limitations.
Land Use			
Construction	• Construction of all project elements would entail the conversion of approximately 195 acres of land from predominantly undeveloped, vacant land to developed industrial uses. This acreage includes 110 acres of undeveloped and agricultural land north of Grandview Road that would be permanently altered to provide for wetland mitigation.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any construction impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • No mitigation measures related to land use are proposed.
Operation	• Construction and operation of the project would be consistent with Whatcom County Land Use Plans and generally consistent with the Whatcom County zoning code. The two transmission line elements would require County approval of conditional use and substantial development permits.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • No mitigation measures related to land use are proposed.
Visual Resources, Light, and Glare			
Construction	• Visual impacts resulting from construction are expected to be low to moderate. Construction activities would be visible from Grandview Road, and farm buildings and residences located along Kickerville Road near the transmission system interconnection with Custer-Intalco Transmission Line No. 2. Clearing of the new transmission corridor and installation of transmission towers could be viewed temporarily while the transmission lines are under construction.	• Under the No Action Alternative, the proposed project would not be constructed and existing views of the project site would be maintained. Views to the site could be altered when the hybrid poplar trees are harvested. Because the land is zoned for industrial uses, future industrial development on the project site would be likely to occur.	<u>Mitigation Measures Proposed by the Applicant</u> • A Site Management Plan would be prepared and implemented to minimize overall visual impacts of construction activities.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Operation	• Once constructed, the project is expected to introduce low to moderate visual impacts in the immediate vicinity of the project site, depending on the viewer type and viewing distance. • There would be an occasional visible water droplet plume related to the operation of the cooling tower at the cogeneration facility. The visibility of the plume would depend on the ambient temperature and relative humidity. • From the intersection of Blaine and Grandview roads, the proposed cogeneration facility would be moderately visible due to its close proximity to the road. • Under Option 1, there would be no visual impacts associated with the Custer Intalco Transmission Line No. 2. Under Option 2a, the use of larger steel lattice towers may result in a slight increase in effects over the existing towers near residences because of their greater height. Under Option 2b, the closer spacing of the steel monopole towers may reduce the visual effects of individual towers, but the decreased spacing would result in more towers and may offer a slightly greater interruption of views.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any impacts for this element of the environment.	<u>Mitigation Proposed by the Applicant</u> • Project elements would be painted gray. This color is intended to reduce surface glare from direct sunlight. • The cogeneration facility located approximately 340 feet south of the centerline of Grandview Road, creating an opportunity to plant screening trees and shrubs. • Project site lighting would be designed to minimize light spillover and glare.
Population, Housing, and Economics			
Construction	• During construction monthly employment on site would average 372 people, with peak employment of 706 individuals. • The indirect workforce associated with the construction stage of the project would be approximately 210 people • Including relocated employees from indirect labor, relocation could be as high as 180 workers • Tax revenue from construction of the project would accrue to Whatcom County and Washington State, from the following sources: - sales/use tax on equipment: $22.8 million. - sales/use tax on construction services and materials: $4.9 million.	• Under the No Action Alternative, the cogeneration facility would not be constructed. No additional employment or tax revenues would be created, and no workers would relocate to the project area.	<u>Mitigation Measures Proposed by the Applicant</u> • No mitigation measures are proposed.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Operation	• Operation of the cogeneration facility would create approximately 30 full time jobs, and approximately $200,000 per year worth of temporary positions. • Operation of the cogeneration facility would generate Washington State brokerage tax revenues of between $4.5 and $5.3 million annually. • Operation of the facility would generate approximately $6 million in property tax revenues annually • During operation, the cogeneration facility would also pay business and occupation (B&O) and public utility tax to the state of Washington. The total tax paid would likely be on the order of several million dollars per year.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • No operational mitigation measures are proposed.
Public Services and Utilities			
Construction	• Construction traffic associated with the project could affect the use of recreational facilities near the project site. Such effects however would be relatively short term, and would not be likely to significantly affect the public's ability to use these facilities. • It is possible that families choosing to reside within the boundaries of the Blaine School District could add a relatively small number of students to that district's enrollment, which is currently at capacity, however individual family decisions regarding where to reside would determine which schools students in those families would be eligible to attend.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any construction impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • The Applicant would develop response protocols with the Jurisdiction Having Authority, Fire District #7, to ensure that additional support and resources are available from the district and other fire jurisdictions through the District Mutual Aid Agreements.
Operation	• Operation of the cogeneration facility is projected to create 30 new jobs. It is possible that some families who choose to relocate and reside within the boundaries of the Blaine School District could add a relatively small number of students to that district's enrollment, which is currently at capacity.	• Under the No Action Alternative, the project would not be constructed, therefore there would not be any construction impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • No mitigation is proposed.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
	• The Applicant proposes to provide its own security, emergency medical, and fire response infrastructure. It is anticipated that only in an emergency, would local community fire, police, medical services, and other government resources be called upon to help respond to an event at the facility.	• Tax revenue associated with construction and operation of the project would not be realized by the state of Washington and Whatcom County.	
Cultural Resources			
Construction	• The Lummi Indian Nation's second native plant survey has not been completed and the results of this study and its associated archaeological survey may identify important resources or sites in the various project facility areas. • One recorded archaeological site in laydown area 3 in the refinery interface area appears to be insignificant and therefore would not be adversely affected by project construction. • Archaeological surveys have not been conducted for the following project facilities, therefore impacts to cultural resources in these areas are not known: various components in the refinery interface area; BP's 0.8-mile long interconnecting transmission line; Alcoa water pipeline; Access Road 1 area; and the wetland mitigation area. • A professional survey found no cultural resources along the 5-mile-long transmission line corridor from Brown Road to Custer substation. There is a low probability that such resources would be found within this area.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any construction impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • Monitor construction activities would occur within 100 feet of the boundaries of the recorded archaeological site discovered in Laydown Area 3. • A pedestrian survey is planned for the wetland mitigation areas where the ground would be disked to control reed canary grass. • If archaeological resources or human burials were encountered during construction, activities that could further disturb the deposits would be directed away from the find. The Washington State Archaeologist and Lummi Indian Nation cultural resource staff would be contacted. • An archaeological survey should be conducted in areas not previously surveyed. If no significant archaeological resources are discovered, construction activities would not affect cultural resources. If significant resource were found that could be impacted by the project, it is recommended that appropriate mitigation measures be devised before construction begins.
Operation	• Operation of the project would not result in adverse impacts on cultural resources at any of the project components.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any operation impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • No operational mitigation measures are proposed.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
Transportation			
Construction	• Construction of the proposed project would generate 650-1200 average weekday trips during the 25-month construction period. • During construction, some onsite soil would be removed and disposed of at approved sites. Various quantities of fill, including sand and gravel, would also be imported to the site. In addition, construction materials would be brought to the site that would include concrete, sheet and metal piping. Assuming trucks with a 20-cubic-yard capacity, this would result in 7,583 one-way truck trips. • The SR 548/Portal Way intersection would operate at Level of Service (LOS) F during the PM peak hour during peak construction conditions without any mitigation.	• Under the No Action Alternative, traffic volumes in the area would be expected to increase at approximately a 5% per year. Intersections on SR 548 would continue to operate at LOS B or C. The only exception is the SR 548/Portal Way intersection, which would operate at LOS D, which is considered acceptable by WSDOT.	<u>Mitigation Measures Proposed by the Applicant</u> • A Traffic Control Plan would be developed and implemented to ensure safe travel conditions within the Grandview Road and SR 548 rights-of-way. • A responsible person would be designated as the Transportation Coordinator. • The Transportation Coordinator would serve as the point of contact for county and state agencies. • Preferential parking for carpools and vanpools would be established at the site during construction, where practical. • Shift hours would be staggered or adjusted as appropriate to minimize traffic impacts. • Implement Letter of Understanding No. 66 between the Applicant and WSDOT.
Operation	• Operation of the cogeneration facility would generate approximately 140 weekday trips • The level of service at the SR 548/Portal Way intersection would decrease to LOS D, but delays would be short, and no substantial traffic queuing or congestion is expected.	• Under the No Action Alternative, the project would not be constructed; therefore there would not be any impacts for this element of the environment.	<u>Mitigation Measures Proposed by the Applicant</u> • A westbound left-turn lane would be installed on SR 548 at the Blaine Road intersection. • An access road would be located approximately 1,000 feet east of Blaine Road. The access road would be constructed and paved to meet applicable geometric and safety standards.
Health and Safety			
Construction	• Potential health and safety risks present during construction are generally typical of the risks present on major industrial/commercial construction site. Health and safety concerns include the risk of fire and explosion, chemical storage and handling, spill response, collection, storage and disposal of hazardous wastes, the installation of transmission lines, sanitary waste handling, the presence of natural gas, and worker exposure to radiation.	• The Ferndale natural gas pipeline and the BP Cherry Point Refinery have been adjacent to the project site for decades. If the proposed project were not constructed, the worker and public health and safety risks related to the use, storage, collection and treatment of non-hazardous and hazardous chemicals at the refinery would still exist.	<u>Measures Proposed by Applicant</u> • Prior to construction the Applicant would require the engineering, procurement, and construction contractor to prepare an Environmental Health and Safety Program designed to reduce the potential impacts related to risks of fire and explosion, spills, hazardous or toxic materials management and handling.

Table 1-2: Continued

Element of the Environment	Impacts of the Proposal	Impacts of No Action	Measures to Mitigate Impacts
		• Under the No Action Alternative, there would be no additional health and safety risks related to the construction and operation of the proposed project.	• Individual plans to be prepared include: - Fire Prevention and Response Plan, - Medical Emergency Plan, - Spill Prevention Plan , - Hazardous Construction Material Management Plan, and - Explosion Risk Management Plan. • As appropriate, the Applicant's existing health and safety resources may augment the EPC contractor's first aid, fire response, and security personnel. • The EPC contractor would coordinate with the Refinery Fire Marshal and the Whatcom County Fire Department during construction of the proposed project.
Operation	• The potential risks present during operation, maintenance and standby of the proposed project are similar to those present during construction. Types of accidents that could occur that would pose a health and safety risk to individuals at the cogeneration facility, the BP refinery, or in the project vicinity include: the release of anhydrous ammonia, a natural gas explosion or fire, and the release/spill of a hazardous chemical(s).	• The Ferndale pipeline and the BP Cherry Point Refinery have been adjacent to the project site for decades. If the proposed project were not constructed, the worker and public health and safety risks related to the use, storage, collection and treatment of non-hazardous and hazardous chemicals at the refinery would still exist. Under the No Action Alternative, there would be no additional health and safety risks related to the construction and operation of the proposed project.	<u>Mitigation Measures Proposed by Applicant</u> • Plans, procedures, and protocols for managing worker and public health and safety would be developed. These may include: - Safety and Health Manual - Emergency Preparedness Response Plan, and - Fire Emergency Response Operations (FERO) Plan • In addition to the plans, procedures, and protocols listed above, the following plan would be prepared to protect worker and public health and safety during the operation of the proposed project: - Fire Prevention and Response Plan, - Spill Prevention Plan, - Hazardous Waste Management Plan, - Prevention of Natural Gas Plan, and - Explosion Risk Management Plan

CHAPTER 2: PROPOSED ACTION AND ALTERNATIVES

Changes to Chapter 2 of the Draft EIS include new and updated information provided by the Applicant and additional consultation with governmental agencies since the Draft EIS was published. The description of the proposed project has not changed significantly from what was presented in the Draft EIS; however, the 404 (B) (1) Alternatives Analysis has been revised including renumbering the alternative sites. The revised analysis is presented in Appendix A of this Final EIS, and revisions to the text in the Draft EIS are presented below.

2.2.2 Project Facilities

- On Page 2-6 of the Draft EIS, the first sentence of the second paragraph should be deleted and replaced with the following text.

> The proposed project includes a cogeneration facility and related components that would be located on an approximately 265-acre site, which includes the 71-acre Bonneville right-of-way.

- On Page 2-6 of the Draft EIS, the following bulleted items should be added to the list after the fourth paragraph.

> - Emergency firewater pump;
> - Water treatment facilities;

- On Page 2-6 of the Draft EIS, the fifth bullet should be deleted and replaced with the following text.

> - One 185 million volt amp (MVA) nominal step-up transformer;

- On Page 2-6 of the Draft EIS, the following item should be added to the second bulleted list at the bottom of the page.

> - One 275 MVA step-up transformer;

- On Page 2-8, a portion of Table 2-1 should be revised. The row that lists the component "Electrical Distribution and Control Systems" should be replaced with the following text. The word "universal" in the second column has been replaced with the word "uninterruptible."

Electrical Distribution and Control Systems	Includes power distribution centers, switchgear, and associated metering and control systems for 480V and 4160V systems, and uninterruptible power supply and 125V backup systems.	Applicant	Applicant	EFSEC Corps

- On Page 2-9, the first three rows of components in Table 2-1 should be deleted and replaced with the following rows. Changes have been made under the Construction Responsibility and Owner/Operator columns.

Component	Component Description	Construction Responsibility	Owner/ Operator	Permits and Approvals
Water Supply Connection and Piping	The PUD delivers water to the refinery via an existing 24-inch underground pipeline along Aldergrove Road. New 16-inch piping (location to be determined) would be installed at one of the existing but unused flanges on the 24–inch pipeline.	Whatcom PUD	Whatcom PUD, at fenceline (Torpey, pers. comm., 2004)	Whatcom County and Ecology
Natural Gas Connection and Pipes	A new connection and natural gas pipes would be installed at the existing metering station for the Ferndale pipeline to support both cogeneration and refinery operations. The new pipes would be routed underground from the metering station to the new compressor station approximately 300 feet west. A connection from the compressor station to the refinery would be made with approximately 300 feet of new piping routed back under Blaine Road to connect with existing piping at the metering station. The connection from the compressor station to the cogeneration facility would be via new piping routed along the elevated piperack.	Applicant	Applicant	EFSEC
Natural Gas Compressor Station	A new compressor station would be installed within the refinery approximately 450 feet west of the cogeneration facility, and would include three electrically driven natural gas compressors enclosed in a single building.	Applicant	Applicant	EFSEC

- On Page 2-10, the second component row in Table 2-1 should be deleted and replaced with the following row.

Modifications to Refinery Substation MS3	The 230-kV switchyard would be a breaker and a half arrangement. The Bonneville interconnection would be two 230-kV receiving structures, four 230-kV circuit breakers, eight disconnect switches, and associated metering, protection, control, and communication. The project interconnection to the switchyard would include four 230-kV receiving structures and two 230-kV receiving structures for refinery interconnection. The remaining project interconnection would include eight circuit breakers, 24 disconnect switches, and associated protection, control, and communication. This results in a split of approximately 35% Bonneville and 65% project.	Refinery	Refinery	--

- On Page 2-13 of the Draft EIS, portions of Table 2-2 should be revised. The second row (Boiler Feedwater and Condensate Storage Tank) should be deleted and replaced with the following. The working capacity has been changed from 500,000 to 600,000.

Boiler Feedwater and Condensate Storage Tank - Storage for boiler feedwater (BFW) and condensate returned from the refinery before polishing treatment in demineralizer system	Vertical, cylindrical, atmospheric aboveground tank	600,000	52	32	--

- On Page 2-13 of the Draft EIS, portions of Table 2-2 should be revised. The third row (Demineralized Water Storage Tank) should be deleted and replaced with the following. The working capacity has been changed from 100,000 to 200,000.

Demineralized Water Storage Tank - Provide makeup BFW in case water delivery or treatment is temporarily interrupted	Vertical, cylindrical, atmospheric above ground tank (open vented)	200,000	--	--	--

- On Page 2-13 of the Draft EIS, portions of Table 2-2 should be revised. The 16th row (Wastewater Equilization Tank) should be deleted and replaced with the following. The working capacity has been changed from 400,000 to 500,000.

Wastewater Equalization Tank	Vertical, cylindrical, atmospheric aboveground tank (open vented)	500,000	52	26	--

- On Page 2-13 of the Draft EIS, portions of Table 2-2 should be revised. The 18th row (Filtered Water and Firewater Storage Tank) should be deleted and replaced with the following. The working capacity has been changed from 425,000 to 500,000.

Filtered Water and Firewater Storage Tank	Vertical, cylindrical, atmospheric aboveground tank	500,000	43	40	--

- In the first paragraph on Page 2-18 of the Draft EIS, the second to the last sentence should be deleted and replaced with the following.

The detention pond would be constructed as an unlined pond.

- In the second paragraph on Page 2-18 of the Draft EIS, the last sentence should be deleted and replaced with the following.

Stormwater contained in the secondary containment areas would be evaluated prior to discharge. If the water is not contaminated, it would be routed to the stormwater collection and treatment system. If the water is contaminated, it would be routed to the refinery's wastewater treatment system.

- On Page 2-19 of the Draft EIS, the last two sentences in the fifth paragraph should be deleted and replaced with the following text.

> Alcoa Intalco Works uses a maximum of approximately 2,780 gpm of water. The cogeneration facility would require an average of 2,244 to 2,316 gpm of industrial water, although maximum instantaneous use could be greater than 2,780 gpm. When the aluminum smelter is operational, the average remaining 484 to 556 gpm of recycled water would be used by the refinery to provide a similar reduction in the amount of freshwater that needs to be withdrawn from the Nooksack River. When instantaneous use exceeds 2,780 gpm, the Whatcom County PUD would provide makeup water.

- On Page 2-26 of the Draft EIS, the following text should be added at the end of the first paragraph.

> It is not know at this time whether the existing pipeline between Alcoa Intalco Works and the BP Cherry Point Refinery is adequate to carry the recycled water. If new construction is necessary, it will be done by the PUD, which will be required to obtain the appropriate permits.

- On Page 2-26 of the Draft EIS, the second sentence of the last paragraph should be deleted and replaced with the following text.

> Rerouting stormwater runoff would include installing pipes, culverts, and an inlet channel with diffuse-flow outlets to direct runoff from the proposed detention pond at the cogeneration facility to CMA 2 rather than letting all of it go through a roadside ditch directly to Terrell Creek.

2.2.3 Construction

- On Page 2-28 of the Draft EIS, the second sentence of the fourth paragraph should be deleted and replaced with the following text.

> The Application for Site Certification indicates that pile-supported concrete foundations would be used for all major equipment and buildings.

- On Page 2-29 of the Draft EIS, the last two sentences in the second paragraph should be deleted and replaced with the following text.

> In general, pipeline trenches would be 5 feet deep depending on soil conditions and the water table, and considering the engineering analysis of expected loads. Minimum fill would be sufficient to bring the trench level with the original grade, but it also would depend on the excavation of loads from vehicle traffic that may pass over the pipeline at designated points.

- On Page 2-30 of the Draft EIS, the first sentence of the first full paragraph should be deleted and replaced with the following text.

> The 0.8-mile 230-kV double-circuit transmission line would be installed within a new transmission ROW on Applicant-owned land not to exceed 150 feet in width.

2.2.4 Schedule and Workforce

- On Page 2-35 of the Draft EIS, the first sentence of the third paragraph should be deleted and replaced with the following text.

> In general, the cogeneration facility is designed to allow maintenance to occur without a complete plant shutdown; however, maintenance on mechanical parts of the steam turbine would most likely require a complete plant shutdown.

2.3 NO ACTION ALTERNATIVE

- On Page 2-36 of the Draft EIS, the following sentence should be added at the end of the first paragraph.

> Finally, additional tax revenues and jobs would not be created within Whatcom County.

- On Page 2-37 of the Draft EIS, the following text should be added at the end of the first paragraph.

> If the proposed project is not constructed, it is likely that the region's long term need for power would be addressed by user-end energy efficiency and conservation measures, by existing power generation sources, or by the development of new renewable and non-renewable generation sources. Baseload demand would likely be filled through expansion of existing, or development of new, thermal generation such as gas-fired combustion turbine technology.

2.4 ALTERNATIVES CONSIDERED BUT REJECTED

- Since publication of the Draft EIS, the Applicant revised the 404 (B) (1) Alternative Analysis, which is presented in Appendix A in this Final EIS. This latest revision of the analysis modified site numbers, which in turn requires changes to the text and Figure 2-4 under this section. On Page 2-37 of the Draft EIS, the second paragraph and list of sites should be deleted and replaced with the following text.

> In addition to the proposed cogeneration facility site (Site 1), five other potential sites on the Applicant's property were evaluated for the facility location. They are as follows (see Figure 2-4):

Site 1	South of Grandview Road and east of the refinery.
Site 2	South of Site 1 and just north of Brown Road and east of the refinery and the proposed Brown Road Materials Storage Area.
Site 3	South of Brown Road (and Site 2) and adjacent to the east of the refinery.
Site 4	Northeast corner of the refinery south of Grandview Road and west of Blaine Road.
Site 5	Located within the refinery in the area previously used for refinery turnarounds (maintenance).
Site 6	Area located just north of Grandview Road.

- Figure 2-4 in the Draft EIS should be deleted and replaced with the new Figure 2-4, which is located at the end of this section.

- On Page 2-40 of the Draft EIS, the last sentence before Table 2-5 should be deleted and replaced with the following.

Appendix A contains the 404 (B) (1) Alternatives Analysis.

- On Page 2-40 of the Draft EIS, Table 2-5 should be deleted and replaced with the following table.

Table 2-5: Summary of Ratings of Alternative Cogeneration Facility Sites

Site	Size	Proximity to Refinery	Security	Accessibility	Wetland Impacts
1	Meets Criterion	Meets Criterion	Meets Criterion	Meets Criterion	12 acres
2	Meets Criterion	Meets Criterion	Meets Criterion	Meets Criterion	31 acres
3	Meets Criterion	Meets Criterion	Meets Criterion	Meets Criterion	33 acres
4	Meets Criterion	Meets Criterion	Meets Criterion	Meets Criterion	About 20 acres
5	Fails Criterion	Meets Criterion	Meets Criterion	Meets Criterion	2.5 acres
6	Meets Criterion	Fails Criterion	Fails Criterion	Meets Criterion	unknown

- In the Draft EIS, the last three paragraphs on Page 2-40 and the first two paragraphs on Page 2-41 of the Draft EIS should be deleted and replaced with the following text.

<u>Site 2</u>

Site 2 was the first site investigated for the cogeneration project. The site was delineated for wetlands and it was determined that the site is approximately 80% wetlands (30 acres). Although this site rated high in most criteria, the Applicant did not select this site because of greater impacts on wetlands compared to the proposed site.

<u>Site 3</u>

Site 3 is just south of Brown Road and Site 2, and adjacent to the east refinery fence. Site 3 has at least 40 acres available for future development. Although Site 3 would meet four of the five evaluation criteria, it would potentially affect up to 33 acres of wetlands. Therefore, the Applicant did not select this site as a possible location for the cogeneration facility.

Site 4

Site 4 is located within the refinery's boundary fence just south of Grandview Road and west of Blaine Road. This area is used for construction laydown and contractor parking during maintenance programs at the refinery. Portions of Site 4 were delineated for wetlands, and a reconnaissance of the remaining area indicates that the overall site is approximately 80% wetlands (23.5 acres). If Site 4 were chosen for the cogeneration facility site, Site 1 would be required for equipment laydown areas and the wetland areas east of Blaine Road would be affected. Site 4 would also affect Wetland I, which would not be affected by using Site 1 for the project. In addition, the Clean Fuels Project will be constructed by the refinery in the space that is currently used as a maintenance laydown area, which means that the refinery will need additional maintenance laydown space in the future. The Applicant did not select Site 4 as the preferred site because it would have greater wetland impacts than the proposed site and it would make future refinery activities more difficult.

Site 5

Site 5 would provide only 16 acres of space for facility construction. Site 5 also interferes with future refinery modifications. Future refinery process units, such as isomerization and clean diesel units, require a much greater level of interconnection than the cogeneration facility. Because of the interconnections, these process units must be located near existing process units. Therefore, the Applicant did not select this site as a possible location for the cogeneration facility site.

Site 6

Site 6 was evaluated because it contains moderately sized upland area adjacent to Grandview Road. The site is located approximately 0.5-mile east of the refinery on the north side of Grandview Road. This site would require significantly longer segments of piping to deliver steam to the refinery and would also require a 0.5-mile new transmission line to the refinery. The steam pipeline to the refinery would be difficult to construct because existing gas and water pipelines and electrical transmission lines are south of Grandview Road. The Applicant did not select Site 6 because of the distance from the refinery that would result in new utility corridors to the refinery. In addition, the new utility corridors would be less secure than other proposed sites.

2.4.3 Alternative Cooling Systems

- On Page 2-43 of the Draft EIS, the first sentence of the last paragraph should be deleted and replaced with the following text.

A number of design and cost factors were evaluated in the Applicant's decision to initially propose ACC. The Applicant considered a dry cooling system using an ACC for the proposed project to minimize water use; however, after the initial selection of the ACC, an agreement was reached between the Applicant, Whatcom County PUD, and Alcoa Intalco Works allowing purchase of cooling water from the Alcoa Intalco Works. With the availability of recycled water, the size of the cooling system (footprint) would be reduced, costs would be reduced, and environmental impacts would also be reduced as described in the following paragraphs.

- On Page 2-44 of the Draft EIS, the following text should be added at the beginning of the second paragraph.

Regarding cost and efficiency, a water cooled system would cost approximately $6 million, one-third of the cost of an ACC system. A water-cooled plant is 1.6% more efficient than an ACC. For a project of this size, this represents an output of 12 MW of power that would have been lost if an ACC system were chosen.

Finally, the ACC system requires a larger footprint and has greater visual impacts. Choosing a wet cooling system allows the Applicant to minimize the overall project footprint and resulting impacts on wetlands by bringing the stormwater detention pond into the facility fenceline.

2.7 COORDINATION AND CONSULTATION WITH AGENCIES, INDIAN TRIBES, THE PUBLIC, AND NON-GOVERNMENTAL ORGANIZATIONS

- Additional coordination has occurred since the Draft EIS was published. On Page 2-50 of the Draft EIS, the following lines should be added at the end of Table 2-7.

9/5/03	Issuance of Draft Environmental Impact Statement for Public Comment
10/1/03	Public Comment Meeting on Draft EIS
11/7/03	Issuance of draft Prevention of Significant Deterioration/Notice of construction Permit, draft State Waste Discharge permit, and Recommendation for 401 Certification Conditions
12/8/03 to 12/11/03	EFSEC Adjudicative Hearings and Land Use Hearing
12/9/03	EFSEC Public Witness Hearing (including comment on draft permits)
1/26/04	BPA Consultation with US Fish and Wildlife Service, and NOAA Fisheries
6/14/04	U.S. Army Corps of Engineers Consultations with OAHP
7/2/04	Draft NPDES permit issued for Public Comment
7/26/04	Reconvened EFSEC Settlement and Land Use Hearing
8/5/04	Public Comment Hearing on draft NPDES permit

Figure 2-4

CHAPTER 3: EXISTING CONDITIONS, IMPACTS, AND MITIGATION

This chapter presents new and/or updated information about existing environmental conditions, potential impacts, and mitigation that has been agreed to since the Draft EIS was published. Some commenters provided additional information in their comments on the Draft EIS. Information has also been updated based on ongoing refinements to the design of the proposed project and additional studies. Settlement agreements addressing mitigation for a number of resources (wildlife, greenhouse gas, and others) have been reached between the Applicant and interestedagencies and organizations. Information from the agreements and testimony presented to EFSEC is described and/or referenced in the revisions to the Draft EIS. Copies of the settlement agreements are available from EFSEC.

The main types of revisions made to the Draft EIS are described below; these changes have incorporated revised design information and results of ongoing studies. Those sections of Chapter 3 that are revised follow this summary.

Please note that updated or revised text is enclosed in boxes (as this paragraph has been) to distinguish it from other explanatory text.

- The Applicant has made revisions to the project design since the Draft EIS was published. For example, various chemical storage tank sizes have been increased. Also, pile-supported concrete foundations would be used for all major equipment items and buildings, and the Applicant would construct, own, and operate the cogeneration facility's natural gas supply connection, associated piping, and natural gas compressor station within the refinery. These design changes and others are described in Chapters 1 and 2 and summarized below where they relate to specific environmental resources.
- The air quality analysis (Section 3.2) has been revised and expanded based on updated information from the Applicant and in response to comments on the Draft EIS. Additional information on secondary particulate, estimates of actual emissions from the cogeneration facility, emissions during startup and shutdown, and measures to mitigate greenhouse gases have been added to the section. Information from the review process for the Prevention of Significant Deterioration (PSD) permit is also described in the section. Unlike other sections of this Final EIS, Section 3.2 has been reprinted in its entirety.
- Figure 3.3-8 (Section 3.3) has been updated to reflect the current location of the stormwater detention pond and the cooling water tower. In addition, as a measure to minimize the potential drainage impact on Wetland C, the Corps of Engineers will not permit the Applicant to install a perimeter ditch along the west side of Wetland C. The perimeter ditch in this location has therefore been deleted as a mitigation measure. Also, the identification of additional recommended mitigation measures has been deleted from this section and all other applicable sections in the Final EIS.
- Since the Draft EIS was published, EFSEC has issued a draft State Waste Discharge permit for public comment. The draft permit requires that the Applicant develop a plan to characterize water used for hydrostatic testing and to specify criteria that will need to be met before the water is discharged to the refinery's wastewater treatment system, including a disposal option if these criteria are exceeded.

- Based on comments received on the Draft EIS, the discussion of secondary and cumulative impacts has been expanded in some sections, in particular because such impacts may apply to other development in the area, such as the BP Refinery ISOM Project.
- Based on a Settlement Agreement between the Applicant and Whatcom County, additional mitigation measures have been included in Section 3.9 for noise emissions and Section 3.7 for potential impacts on local heron populations.
- Information from the WDFW Priority Habitat and Species database has been added to Section 3.7, and additional information on the potential impacts resulting from the discharge of treated wastewater on the herring stock in the Strait of Georgia has been included in this section.
- Table 3.8-4 has been revised and a new table has been added to Section 3.8 (Energy and Natural Resources). The revised Table 3.8-4 lists generation facilities currently under construction in Washington. The new Table 3.8-7 presents a summary of proposed combustion turbine facilities in the Pacific Northwest. In addition, Section 3.8.4 (Secondary and Cumulative Impacts) has been updated.
- The description of potential noise impacts resulting from operation of the proposed project has been updated and clarified in Section 3.9. Also, based on a Settlement Agreement between the Applicant and Whatcom County, additional noise mitigation measures have been added to this section.
- Since the Draft EIS was published, the Corps has consulted with the State Historic Preservation Office (SHPO) regarding potential impacts on cultural resources. SHPO concurred with the Corps' conclusion of No Historic Properties Affected and also concurred with the Corps' proposed mitigation measures to protect cultural resources should they be discovered during construction. These mitigation measures have been included Section 3.14.
- The Applicant and WSDOT have agreed on additional traffic mitigation measures that were described in a Letter of Understanding between the Applicant and WSDOT. The measures have been included in Section 3.15.
- Additional information on transportation and storage of anhydrous ammonia and the method to control bacteria growth in the cooling water tower has been included in Section 3.16.

The following sections of the Draft EIS were not revised and are therefore not discussed further in this Final EIS:

- Section 3.6 Agricultural Land, Crops, and Livestock
- Section 3.11 Visual Resources, Light, and Glare
- Section 3.12 Population, Housing, and Economics
- Section 3.17 Relationship Between Short-Term Uses of the Environment and the Maintenance and Enhancement of Long-Term Productivity
- Section 3.18 Irreversible or Irretrievable Commitment of Resources

3.1 EARTH

The following information has been updated in the Final EIS. Updated information was obtained from S. Malushte's prefiled testimony (Exhibit 32R.0) as presented to EFSEC.

3.1.1 Seismic Hazards

- Before the last sentence in the first full paragraph on Page 3.1-9 of the Draft EIS, the following sentence should be added:

> Although the latter two faults have been hypothesized by Easterbrook (1976), they have not been recognized by the USGS.

- After the first sentence in the last paragraph on Page 3.1-10 of the Draft EIS, the following should be added:

> According to the 1997 Uniform Building Code, this moderate earthquake hazard is designated as Seismic Zone 3. In Seismic Zone 3, structures are to be designed for a PGA of 0.3 gravity. Based on the latest probabilistic seismic hazard assessment data from the USGS, the actual PGA for the project site is 0.23 gravity, or about 25% less than the design criterion.

- Before the first paragraph on Page 3.1-11, the following paragraph should be added:

> Just before the Draft EIS was published, URS (2003) published the results of detailed subsurface investigations and laboratory testing. The results will be used in designing the foundations and structures at the project site. The results of that testing do not alter the conclusions of the Draft EIS.

3.1.5 Mitigation Measures

- On Page 3.1-19 of the Draft EIS, the first sentence in the first paragraph should be deleted and replaced with the following:

> The site was surveyed for soil contamination during the geotechnical survey, and no contamination was found.

- On Page 3.1-20 of the Draft EIS, the heading titled "Additional Recommended Mitigation Measures, Volcanic Hazards" and the text below it should be deleted.

3.2 AIR QUALITY

This section discusses the potential impact on air resources from the BP Cherry Point Cogeneration Project. It addresses potential impacts associated with the proposed project and identifies mitigation measures designed to limit those impacts. The analysis in this section is based on information from the Application for Site Certification prepared for this project (BP 2002).

In addition to evaluating the emissions resulting from the cogeneration facility alone, this section describes the Applicant's estimates of emission reductions that would occur with the cogeneration aspect of the proposal. As indicated in Section 1.2.1, BP Cherry Point Refinery Need, one of the purposes of the cogeneration project is to supply both steam and electricity to the existing refinery. The refinery's purchase of cogeneration facility steam would allow the removal of existing less efficient refinery utility boilers, leading to a reduction in regional emissions of particulate matter less than 10 micrometers in size (PM_{10}) and nitrogen oxides (NO_x). The short and long range air quality impacts of both the cogeneration facility emissions and the refinery reductions are discussed in more detail below.

3.2.1 Regulatory Framework

Under Chapter 80.50 Revised Code of Washington (RCW), the authority for permit review and issuance of air permits is granted to the EFSEC for thermal generating power plants capable of generating 350 MW or more of electricity. The U.S. Environmental Protection Agency (EPA) has delegated to EFSEC the issuance of federal Prevention of Significant Deterioration (PSD) permits for facilities regulated under Chapter 80.50 RCW. EFSEC reviews applications for air emissions resulting from the operation of such facilities pursuant to the requirements of Chapter463-39 WAC. EFSEC has adopted the substantive requirements of the Washington Department of Ecology regulations for air pollution sources as codified in Chapters 173-400 WAC (General Regulations for Air Pollution Sources), Chapter 173-401 WAC (Air Operating Permit Program), Chapter 173-406 WAC (Acid Rain Regulation), and Chapter 173-460 (Controls for New Sources of Toxic Air Pollutants).

Air Quality Standards

<u>United States</u>

The proposed cogeneration facility would be regulated according to applicable U.S. federal and Washington State laws and regulations. Pursuant to the Clean Air Act of 1970, the EPA established air quality standards for the following air pollutants: ozone (O_3), carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), particulate matter (PM), and sulfur dioxide (SO_2). These include primary standards that have been established to protect human health and secondary standards to protect the public welfare. Ecology has also adopted Washington Ambient Air Quality Standards (WAAQS) similar to the National Ambient Air Quality Standards (NAAQS), and has included standards for total suspended particulate (TSP).

Particulate matter includes both naturally occurring and man-made particles with a diameter of less than 10 micrometers or 2.5 micrometers, respectively. Local and regional contributions of particulate matter include sea salt, pollen, smoke from forest fires and wood stoves, road dust, industrial emissions, and agricultural dust. Particles of this size are small enough to be drawn deep into the respiratory system where they can contribute to infection and reduced resistance to disease (Canadian Federal Government 2002).

Table 3.2-1 summarizes the federal and state primary and secondary standards for the criteria pollutants, and the averaging time for determining compliance with the standards. It also presents the increments under the EPA's PSD program and the EPA PSD Class II significance levels for air quality that are applicable to the proposed project.

Canada

For purposes of review of the impacts to air quality on a regional basis, Canadian regulatory standards and objectives were considered. The Canadian Environmental Protection Act provides for three levels of air quality objectives: desirable, acceptable, and tolerable, which correspond to degrees of environmental damage or potential health effects. The Province of British Columbia also has established air quality objectives that are similar to the Canadian national objectives, and, where no comparable federal objectives exist, the Greater Vancouver Regional District (GVRD) has proposed objectives for pollutants of concern within its jurisdiction. Level A is a descriptor used by GVRD that is equivalent to the desirable objective, and Level B is a descriptor that is equivalent to the acceptable objective in the Canadian Environmental Protection Act. The Canadian Ministers of Environment have established nationwide standards for particulate matter less than 2.5 micrometers in size ($PM_{2.5}$) and O_3. These standards establish goals for the year 2010 rather than regulatory limits. Table 3.2-2 summarizes the Canadian National Ambient Air Quality Objectives and Standards.

Regulatory Requirements

The EPA and Ecology have developed air quality regulations and guidelines that require all new or modified "major sources" of air emissions to undergo a rigorous permitting process before commencing construction. The federal program is called New Source Review (NSR). The PSD program is within the overall federal NSR program. The provisions of the federal PSD program are contained in 40 CFR 52.21.

New Source Review

The NSR program applies to new or modified sources that could cause a significant increase in emissions of air pollutants. The objectives of the NSR process are to demonstrate that air emissions from the new source will not significantly impact ambient air quality near the facility and that state-of-the-art emission controls will be applied. NSR incorporates both state and federal requirements.

Table 3-2.1: Ambient Air Quality Standards and Significant Impact Levels

Criteria Pollutants	Averaging Period	National				State of Washington [1]		PSD		EPA Significant Impact Level	
		Primary Standards [1]		Secondary Standards [1]				Class 1	Class II	Class I	Class II
		ppm	µg/m^3	ppm	µg/m^3	ppm	µg/m^3	µg/m^3	µg/m^3	µg/m^3	µg/m^3
Total Suspended Particulate	Annual	--	--	--	--	--	60	--	--	--	--
	24-hour	--	--	--	--	--	150	--	--	--	--
Sulfur Dioxide	Annual	0.03	80	--	--	0.02	52[2]	2	20	0.1	1
	24-hour	0.14	365	--	--	0.10	262[2]	5	91	0.2	5
	3-hour		--	0.5	1300	--	--	25	512	1.0	25
	1-hour	--	--	--	--	0.40[3]	1050[2]	--	--	--	--
PM_{10}	Annual	--	50	--	50	--	50	4	17	0.2	1
	24-hour	--	150	--	150	--	150	8	30	0.3	5
$PM_{2.5}$	Annual	--	15	--	15	--	--	--	--	--	--
	24-hour	--	65	--	65	--	--	--	--	--	--
Carbon Monoxide	8-hour	9	10,000	--	--	9	10,000[2]	--	--	--	500
	1-hour	35	40,000	--	--	35	40,000[2]	--	--	--	2,000
Ozone	1-hour	0.12	235	0.12	235	0.12	235[2]	--	--	--	--
	8-hour	0.08	176	0.08	157	--	--	--	--	--	--
Nitrogen Dioxide	Annual	0.053	100	0.053	100	0.05	100	2.5	25	0.1	1
Lead	Quarterly	--	1.5	--	1.5	--	--	--	--	--	--

Source: WAC 173-400 and 40 CFR 52.21

Notes: µg/m^3 = micrograms per cubic meter

ppm = parts per million by volume, dry basis

1 Annual standards never to be exceeded; short term standards not to be exceeded more than once per year unless otherwise noted.

2 Values are calculated equivalent to regulated value.

3 The 0.40 ppm standard is not to be exceeded more than once per year

Table 3.2-2: Canadian National Ambient Air Quality Objectives and Standards [1]

Pollutant	Averaging Period	Canada Objectives [2] ($\mu g/m^3$)		BC and GVRD Objectives [3] ($\mu g/m^3$)		Canada-Wide Standard ($\mu g/m^3$)
		Desirable	Acceptable	Level A	Level B	
Sulfur dioxide	Annual	30	60	25	50	---
	24-hour	150	300	160	260	---
	3-hour	---	---	375	665	---
	1-hour	450	900	450	900	---
Total suspended particulate	Annual	60	70	60	70	---
	24-hour	---	120	150	200	---
Inhalable particulate (PM_{10}) [4]	Annual	---	---	---	30	---
	24-hour	---	---	---	50	---
Fine particulate ($PM_{2.5}$) [5,6]	24-hour	---	---	---	---	30
Carbon monoxide	8-hour	6,000	15,000	5,500	11,000	---
	1-hour	15,000	35,000	14,300	28,000	---
Ozone	24-hour	30	50	---	---	---
	8-hour [5]	---	---	---	---	127
	1-hour	100	160	---	---	---
Nitrogen dioxide	Annual	60	100	---	---	---
	24-hour	---	200	---	---	---
	1-hour	---	400	---	---	---
Total reduced sulfur	24-hour	---	---	3	6	---
	1-hour	---	---	7	28	---
Lead	Annual	---	---	2	2	---
	24-hour	---	---	4	4	---
Zinc	Annual	---	---	3	3	---
	24-hour	---	---	5	5	---

Source: GVRD 2002

1 The tolerable objective is the least strict of the Canadian objectives, so no column is presented in the table showing these values.
2 Federal objective unless otherwise noted.
3 British Columbia Provincial objective unless otherwise noted.
4 GVRD objective.
5 Canada-wide standard to be achieved by year 2010.
6 Based on the 98th percentile, average over a three-year period, and established by the Canadian regulatory agencies.

To satisfy the general NSR requirements, the following information must be submitted:

- Notice of Construction Application form and associated information. This application form is included at the front of the PSD application.
- PSD Applicability Analysis
- "Top-down" BACT Analysis
- Toxic Air Pollutant Review (WAC 173-460)
- Air Quality Modeling Analysis

The requirements for these separate review elements are described in further detail below.

Prevention of Significant Deterioration

PSD review regulations apply to new or modified sources located in an attainment area that have the potential to emit criteria pollutants in excess of predetermined "*de minimus*" values (40 CFR Part 51). For new generation facilities, these values are 100 tons per year (tpy) of criteria pollutants for 28 specific source categories, including power generating facilities, and 250 tpy for all others. The proposed project would be a PSD source because it would emit more than 100 tpy of NO_x, CO, PM_{10}, and $PM_{2.5.}$ Also, the projected potential to emit annual emissions of volatile organic compounds (VOC), SO_2, and sulfuric acid mist (H_2SO_4) exceeds the individual significant emission rate thresholds listed in WAC 173-400-030. VOC is defined as any organic compound that participates in atmospheric photochemical reactions. Therefore, the proposed project is also subject to PSD review for those pollutants.

The PSD review process evaluates existing ambient air quality, the potential impacts of the proposed source on ambient air quality, whether the source would contribute to a violation of the NAAQS, and a review of the Best Available Control Technology (BACT). It should be noted that although NAAQS have been established for $PM_{2.5}$, the designation of attainment, non-attainment, and unclassified areas has not yet been concluded for this pollutant. As of February 2004, the Department of Ecology has recommended to EPA Region 10 that all areas of Washington State (with the exception of Yakima for which insufficient information was available at the time) be classified as "in attainment/unclassifiable" for $PM_{2.5}$. With respect to review and regulation of $PM_{2.5}$ emissions under the PSD program, in the absence of Significant Impact Levels (SILs) specified in regulation, and lacking established modeling methodologies, compliance with PM_{10} emission standards and thresholds is currently considered a surrogate test for $PM_{2.5}$ (EPA 1997).

PSD restricts the degree of ambient air quality deterioration that would be allowed by assigning increments for criteria pollutants based on the classification (attainment, non-attainment, or unclassified) of the area. PSD increments have been established for certain criteria pollutants and are interpreted as the maximum allowable ground-level increase of a pollutant concentration. Class I areas are assigned to federally protected wilderness areas, such as national parks, and allow the lowest increment of permissible deterioration. This essentially precludes development near these areas. Class II areas are designed to allow for moderate, controlled growth, and Class III areas allow for heavy industrial use, but in all cases the pollution concentrations cannot violate any of the NAAQSs.

The Class I areas closest to the proposed project include North Cascades National Park, Olympic National Park, Glacier Peak Wilderness Area, Alpine Lakes Wilderness Area, and Pasayten Wilderness Area (Figure 3.2-1). The area around the proposed project is designated Class II where less stringent PSD increments apply. Class I and II increments are shown with the ambient air quality standards in Table 3.2-1.

Significant Impact Levels (SILs) are used in the air quality impact analysis. The SILs are a screening tool to determine the extent of the air quality analysis required to demonstrate compliance with the NAAQSs and PSD increments. The SILs are typically 1 to 5% of the ambient air quality standards and are well below any levels that could lead to adverse health or welfare impacts. These SILs are more restrictive than the NAAQSs and the Canadian National Ambient Air Quality Objectives and Standards.

According to analysis methodologies established by Ecology and the EPA, the impact from a source is not required to be below the SILs. However, these levels set a worst-case scenario, so if the impacts of a source are below the SILs, state and federal agencies consider the impacts to be inconsequential and no further evaluation is required.

Finally, the PSD program also requires an analysis of the impairment to soils and vegetation, and an analysis of visibility, regional haze, and deposition impacts on Class I areas.

State/Local Emission Limits and Best Available Control Technology

As part of the PSD process, EFSEC is reviewing the Applicant's evaluation of alternative emission control technologies. The determination of which control technology best protects ambient air quality is made by the regulatory agency on a case-by-case basis taking into account the associated economic, energy, and environmental impacts. The analysis for BACT identifies pollutant-specific alternatives for emission control, and the costs and benefits of each alternative technology. BACT would reduce emissions of toxic air pollutants, along with those of criteria pollutants. For example, low-sulfur fuel, such as natural gas, is a BACT because of its lower emissions of criteria and toxic air pollutants over other fuels, such as fuel oil or coal. Combustion controls also reduce criteria pollutants by optimizing combustion and reducing pollutants emitted in the exhaust stream.

The determination of BACT at the time of the final air emissions permit review would define the emission limits for the proposed project. BACT for NO_x typically consists of dry, low NO_x technology, or SCR, which is a post-combustion control that uses ammonia and a catalyst to reduce NO_x emissions. Any unreacted ammonia is emitted as a toxic air pollutant, however, and is regulated by Washington State.

Other Air Permit Requirements

New Source Performance Standards

The EPA has adopted federal emission standards applicable to various combustion sources. These emission standards are referred to as the New Source Performance Standards (NSPS). EPA set forth the NSPS for stationary combustion turbines in 40 CFR 60, Subpart GG, dated September 1979. These require that NO_x emissions do not exceed 103 parts per million dry volume (ppmdv) at full load operation and that SO_2 emissions not exceed 150 ppmdv. They also prohibit the use of fuel containing more than 0.8% sulfur by weight.

The duct burners are subject to the NSPS for steam generating units in 40 CFR 60, Subpart D(b), which limit the NO_x emission for the duct burners to 0.20 lb/MBtu. No other NSPS emissions standards are applicable to this proposed power generating facility.

Figure 3.2-1

Acid Rain

Title IV of the Clean Air Act (also known as the "acid rain" rules) applies to utility projects that started commercial operation on or after November 15, 1990, produce electricity for sale and do not fall into one of the regulatory exemptions. These rules are contained in 40 CFR Parts 72, 75, and 76 and have been adopted into WAC 173-406. The "acid rain" rules will apply to the proposed project's combustion turbines and duct burners because these units will be utility units serving one or more generators with a nameplate capacity of greater than 25 MW.

The Title IV program consists of three primary requirements. To meet these requirements the Applicant would have to:

1. Submit an "acid rain" permit application at least 24 months before the anticipated date for start of operations,
2. Be subject to requirements for continuous emissions monitoring for NO_x and dilutents gas (O_2 or CO_2) and,
3. Be subject to the "acid rain" recordkeeping and reporting requirements, including the requirement to obtain and document SO_2 allowances.

Hazardous Air Pollutant Regulations

According to EPA Interpretive Rule (Federal Register 65 FR 21363), the proposed cogeneration facility is not categorically exempt from "case-by-case" Maximum Available Control Technology (MACT) determinations (Clean Air Act [CAA] Section 112). However, because no individual hazardous air pollutants (HAP) will have an emission rate greater than 10 tpy and no combination of HAPs will have a total cumulative annual emission rate of greater than 25 tpy, the facility is not subject to the MACT requirements.

The National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, 40 CFR 63 Subpart YYYY, may be applicable to this project. If project approval is granted, applicability would be determined by the Applicant after startup using Test Method 320 of 40 CFR Part 63, including the additional testing provisions of 40 CFR 63 Subpart YYYY, or using other methods approved by EFSEC. If the potential to emit formaldehyde is greater than 10 tpy from the site, the provisions of Subpart YYYY shall be applicable.

Washington State also requires the review of toxic air pollutant (TAP) emissions in accordance with WAC 173-460, Controls for New Sources of Toxic Air Pollutants.

Title V – Air Operating Permit

The cogeneration facility would be subject to the federal Clean Air Act Part 70 – Title V air operating permit program. The Applicant would have to file a permit application 12 months after facility operations commence.

Title III – Prevention of Accidental Releases

Because the cogeneration facility proposes the use of anhydrous ammonia in the SCR emissions control system, the facility could become subject to the Prevention of Accidental Release provisions of the 1990 Clean Air Act Amendment, Section 112. If the proposed cogeneration facility is subject to these provisions, the refinery's Risk Management Plan would be revised to cover storage, handling, and use of ammonia. Applicable regulations that would be followed in revising the plan include 40 CFR 68, Chapter 90.56 RCW, and the Hazardous Substances/Worker Community Right to Know Act, Chapters 70.105, 70.136 RCW, and 49.70 RCW.

3.2.2 Existing Conditions

Climate

The proposed project is in the Puget Sound lowlands, a north-south topographical depression bordered on the east by the Cascade Mountains and the west by the Olympic Mountains and Vancouver Island. The project site is located in an area known as the Mountain View upland. The climate at the site is influenced by marine air that flows east from the Pacific Ocean and through the Straits of Georgia and Juan de Fuca. Occasionally, cold, dry continental air flows from the east-northeast through the Fraser River canyon.

According to data from the BP Cherry Point Refinery's meteorological seven-year monitoring program (1995-2001), the maximum high temperature recorded was 86°F (1998) and the record low temperature was 10°F (1996). Over the seven years of monitoring, January and December had the lowest temperature average of 40°F while July and August had the highest average of 60°F. Relative humidity is not measured as part of the BP meteorological measurements program. However, other published data demonstrate the influence of the marine climate at the project site. Afternoon humidity readings are typically in the 60% range during summer months and in the mid- to upper 80% range during winter months (Pacific Northwest River Basin Commission 1968). Higher relative humidity can be expected with the passage of migratory storm systems from the west. Lower humidity can be expected with high pressure over eastern British Columbia and eastern Washington.

Predominant winds at the project site are from the south to south-southwest and from the east-northeast. On an annual basis, winds from the south and south-southwest occur with a frequency of about 24%. Winds from the east or east-northeast occur about 21% of the time, and winds from the west to northwest occur about 20% of the time

Dust

The air in the vicinity of the project site is generally free of dust. The area around the site is predominantly rural, agricultural land with some populated areas within a few miles of the site. The agricultural land is predominantly covered with grass and is used for cattle grazing. Typical farming activities, such as soil tilling that create dust clouds, occur infrequently.

Dust-control measures regulated by the Northwest Air Pollution Authority (NWAPA) are aimed at preventing particulate matter from becoming airborne from untreated open areas (NWAPA 2003).

Odor

Over the past three years the NWAPA has received several odor-related complaints due to the existing refinery. A sulfur smell has been the most prevalent complaint, however, local officials who responded to the complaints have not detected or found any of these odors. Compared to other facilities of this type, the existing refinery has received minimal complaints (Billington, pers. comm., 2003).

Existing Air Quality

<u>United States</u>

Based on air quality monitoring information, Ecology and the EPA designate geographic regions as being in "attainment" or "nonattainment" if the region is in compliance or noncompliance with air pollutants listed under the NAAQSs (Table 3.2-1). Whatcom County and the surrounding area are in attainment for all air pollutants regulated by the NAAQS and the WAAQS.

The NWAPA operates monitoring sites for a variety of air pollutants within Whatcom County. Pollutants monitored by or reported to the NWAPA include SO_2, PM_{10}, $PM_{2.5}$ and O_3. Data are reported as an air quality index (AQI) where levels are characterized as good, moderate, or unhealthful.

Data from the Lynden-Custer site indicate that no moderate or unhealthful days occurred in calendar year 2001 (all 365 days were in the "good" range). At the more urban Bellingham site, there were no moderate or unhealthful days for PM_{10} (all 365 days were in the "good" range) and there were 6 days where the $PM_{2.5}$ air quality index was in the moderate range. The Lynden-Custer site is representative of a rural "background" area while the Bellingham site is representative of a more mixed urban and rural area, where higher pollution levels are typically expected.

In Bellingham (Yew Street), PM_{10} is collected continuously by a Rupprecht and Patashnick TEOM 1400 sampler. These data are summarized and reported by the NWAPA. For the years summarized, the maximum 24-hour PM_{10} concentration was 53 micrograms per cubic meter ($\mu g/m^3$). According to the three-year data presented, the maximum annual average PM_{10} concentration in Bellingham was 13.7 $\mu g/m^3$. In March 1999, this PM_{10} sampler was moved to its current Yew Street location from its previous location on Iowa Street.

NWAPA has operated a $PM_{2.5}$ sampler in Bellingham since February 1999 (Yew Street). This site is currently co-located with the Bellingham PM_{10} measurements. The NWAPA also reports ozone data for a Lynden-Custer site. For calendar year 2001, no moderate or unhealthful days were experienced (all 365 days were in the "good" range). BP also operates an SO_2 monitor at the refinery. According to the NWAPA data summary for SO_2 at Blaine, all 365 days in calendar year 2001 were in the "good" range.

Air quality monitoring indicates that since 1999 (for PM_{10}, $PM_{2.5}$) and 2001 (for SO_2 and O_3), no moderate or unhealthful days have been recorded in Whatcom County.

Canada

Ambient air quality data have also been summarized by pollutant for the closest ambient monitoring stations in Canada. The Surrey and Langley sites are the closest sites in Canada to the project that monitor PM_{10}, CO, NO_x, and O_3. They are located approximately 16.2-mile to the north and northeast, respectively, from the cogeneration project site. The Richmond and Abbotsford sites are the closest sites in Canada that monitor SO_2, and they are located 23 miles to the northwest and 22 miles to the northeast, respectively, from the cogeneration project site. Pitt Meadows and Vancouver Airport are the closest sites in Canada to the cogeneration project site that measure $PM_{2.5}$, and they are located 24 miles to the north and 27 miles to the northwest, respectively, from the project site. A summary of the ambient monitoring sites is shown in Table 3.2-3.

Table 3.2-3: Ambient Monitoring Stations in Canada

Station	Station ID	Distance from Project Site (miles)	Direction from Project Site	Pollutants Measured
Surrey	T15	16.5	N	PM_{10}, CO, NO_2, O_3
Richmond	T17	23.1	NW	SO_2
Pitt Meadows	T20	24.5	N	$PM_{2.5}$
Langley	T27	16.3	NE	PM_{10}, CO, NO_2, O_3
Vancouver Airport	T31	27.0	NW	$PM_{2.5}$
Abbotsford	T33	22.3	NE	SO_2

For the Canadian air quality data, the maximum and 98th percentile concentrations for each pollutant and averaging time are summarized in Table 3.2-4. Concentrations are listed for 1999 through 2001 for the closest two ambient monitoring stations for each pollutant. The maximum values of the three years and the two stations are also listed.

Table 3.2-4: Background Concentrations in Canada [1]

Pollutant	Averaging Period	Ambient Monitoring Station 1			Ambient Monitoring Station 2			Maximum
		1999	2000	2001	1999	2000	2001	
Maximum Concentration ($\mu g/m^3$)								
SO_2	Annual	3	3	3	3	1	3	3
	24-hour	11	13	8	5	5	8	13
	3-hour	19	27	16	19	21	13	27
	1-hour	29	35	29	27	27	29	35
PM_{10}	Annual	12	13	12	12	13	12	13
	24-hour	34	31	39	32	34	33	39

1 Ambient Monitoring Station 1 is Surrey for PM_{10}, CO, O_3, and NO_2, Richmond for SO_2, and Pitt Meadows for $PM_{2.5}$. Ambient Monitoring Station 2 is Langley for PM_{10}, CO, O_3, and NO_2, Abbotsford for SO_2, and Vancouver Airport for $PM_{2.5}$

Table 3.2-4: Continued

Pollutant	Averaging Period	Ambient Monitoring Station 1			Ambient Monitoring Station 2			Maximum
		1999	2000	2001	1999	2000	2001	
$PM_{2.5}$	Annual	8	9	5	9	9	5	9
	24-hour	24	22	21	23	29	19	29
CO	8-hour	2,436	1,740	1,624	2,668	1,740	1,508	2,668
	1-hour	2,900	2,900	2,900	2,900	2,784	4,060	4,060
NO_x	Annual	23	27	21	17	17	17	27
	24-hour	69	67	55	52	48	42	69
	1-hour	107	99	90	84	88	73	107
Ozone	24-hour	88	84	80	94	86	84	94
	1-hour	140	138	166	142	134	160	166
98th Percentile Concentrations for Short-Term Averaging Periods ($\mu g/m^3$)								
SO_2	24-hour	5	8	5	5	5	5	8
	3-hour	8	11	8	5	8	5	11
	1-hour	21	24	16	19	19	11	24
PM_{10}	24-hour	24	25	25	26	27	24	27
$PM_{2.5}$	24-hour	17	19	15	17	21	15	21
CO	8-hour	1,276	1,044	1,044	1,160	1,044	928	1,276
	1-hour	1,276	1,160	1,740	1,276	1,160	1,624	1,740
NO_x	24-hour	50	52	46	34	32	36	52
	1-hour	61	69	78	48	46	63	78
Ozone	24-hour	72	68	70	76	72	68	76
	1-hour	90	88	112	94	88	114	112

1 Ambient Monitoring Station 1 is Surrey for PM_{10}, CO, O_3, and NO_2, Richmond for SO_2, and Pitt Meadows for $PM_{2.5}$. Ambient Monitoring Station 2 is Langley for PM_{10}, CO, O_3, and NO_2, Abbotsford for SO_2, and Vancouver Airport for $PM_{2.5}$

Monitoring Stations

The GVRD operates air quality monitoring stations in the Lower Fraser Valley of British Columbia. Similar to the United States, Canada's AQI is a measure derived by the GVRD and Lower Fraser Valley Ambient Air Quality Reports. Based on the index criteria, an AQI of less than 25 indicates good air quality. An AQI of 26 to 50 represents fair air quality levels. From 51 to 100, the AQI level is considered to be poor, and above 101 the air quality is considered to be very poor.

Air quality classified as good would show that air contaminants are near the background (ambient) levels, in which air quality poses little health risk within the region. Presently, 98% of the time air quality is at or below this level. Fair air quality within the region reflects that air contaminant levels are relatively low; however, sensitive individuals and ecosystems may have adverse effects. Currently, air quality is at this level less than 2% of the time. Poor air quality may adversely affect humans, animals, water, and vegetation. On average, air quality is at this level only for a few hours each year. Finally, very poor air quality can pose significant health and environmental risks within the region, leading to immediate government action (GVRD 2003).

Air quality in areas of British Columbia immediately north of the proposed project site is characterized in the good range with some hours characterized as fair. To characterize the existing air quality for areas closest to the U.S./Canada border, the most recent data available from a selection of monitoring stations were evaluated (Surrey, Richmond, Langley, and Abbotsford) and are summarized in Table 3.2-5. Poor and very poor air quality conditions were not recorded at any of these locations in 2000.

Table 3.2-5: GVRD Air Quality Index Data for 2000 and 2001 [1]

Station	PM_{10} (24-hour)	SO_2 (1-hour)	CO (1-hour)	O_3 (1-hour)	NO_2 (1-hour)
	2000/2001	2000/2001	2000/2001	2000/2001	2000/2001
Total hours per year with an AQI level of good					
Surrey	8657/8621	NM/NM	8760/8760	8728/8721	8760/8760
Richmond	8476/8543	8760/8760	8760/8760	8748/8718	8760/8760
Langley	8557/8690	NM/NM	8760/8760	8720/8696	8760/8760
Abbotsford	8525/8489	8760/8760	8760/8760	8741/8712	8760/8760
Total hours per year with an AQI level of fair					
Surrey	103/139	NM/NM	0/0	32/39	0/0
Richmond	284/217	0/0	0/0	12/42	0/0
Langley	203/70	NM/NM	0/0	40/64	0/0
Abbotsford	235/271	0/0	0/0	1948	0/0
Total hours with an AQI level of poor or very poor					
Surrey	0/0	NM/NM	0/0	0/1 [2]	0/0
Richmond	0/0	0/0	0/0	0/0	0/0
Langley	0/0	NM/NM	0/0	0/0	0/0
Abbotsford	0/0	0/0	0/0	0/0	0/0

Source: GVRD 2002, 2003
NM-The criteria pollutant was not monitored at this location.
Note: SO_2 is not measured at the Surrey and Langley monitoring stations.
1 Data for calendar year 2001 are the latest available from GVRD.
2 Surrey East 2001 data contained 1 hour with an AQI of "poor"

Sources of Air Pollution in the Project Area

Existing emission sources in the project vicinity include the adjacent refinery, the Alcoa Intalco Works aluminum smelter (approximately 3 miles south-southeast of the project site), the Conoco-Phillips Refinery (approximately 5 miles south-southeast), and the Tenaska Washington Cogeneration power plant (approximately 5 miles to the south-southeast). The NWAPA and Ecology regulate all of these sources.

The Applicant issues annual reports to NWAPA and Ecology for review. These documents contain yearly emission data from the existing facility and are available to the public.

3.2.3 Impacts of the Proposed Action

Construction

Cogeneration Facility

Dust

The use of heavy equipment on the project site during the construction phase would generate dust. Late in the construction process onsite roads and parking areas would be constructed with asphalt over a compacted subbase.

Odors

This would be a localized air emission and is not anticipated to produce an impact.

Natural gas will be supplied to the site primarily through the existing refinery connections to the proprietary Ferndale pipeline, which connects to the West Coast Energy Pipeline at the U.S./Canada border near Sumas. If a leak occurs before preventative instrumentation/measures are conducted, a short term odor may occur.

Combustion emissions would result from diesel construction equipment, various diesel-fueled trucks, and the private vehicles of workers commuting to the construction site. All site preparation would be completed using conventional methods of construction. General construction equipment would include, but is not limited to: heavy, medium, and light equipment such as excavators, roller compactors, front end loaders, bulldozers, graders, backhoes, dump trucks, water trucks, concrete trucks, pump trucks, utility trucks, cranes, and pile drivers.

Refinery Interface, Transmission System, Custer/Intalco Transmission Line No. 2, and Other Project Components

Construction of the pipelines, transmission lines, and other project components would generate short term emissions, including fugitive dust and construction equipment exhaust emissions. Fugitive dust would be controlled by conventional construction practices (e.g., road watering, covering of dirt piles) to comply with state regulations.

Operation and Maintenance

The following section relates to information dealing with the operation and maintenance of the proposed cogeneration facility. All other aspects of the proposed project such as the refinery interface, transmission system, Custer/Intalco Transmission Line No. 2, and other project components are not addressed because of the lack of air emissions.

Emission Sources and Emission Controls

The principal sources of emissions from the proposed project during startup and operation would occur from up to three combustion turbines fired by natural gas, and three HRSGs.

Each HRSG would be equipped with low NO_x duct burners and with selective catalytic reduction and oxidation catalyst systems for the removal of NO_x and CO, respectively. Steam will be produced at high pressure in the HRSG and sent to a single STG. For additional information, see Chapter 2 of the Draft EIS.

The three combustion turbines would be equipped with dry low NO_x combustors that minimize the formation of NO_x and CO. GE would guarantee exhaust concentrations from the combustion gas turbine of 9 parts per million (ppm) for both NO_x and CO. A SCR catalyst bed and ammonia injection grids for the control of NO_x emissions will be installed in the HRSG, as well as a catalytic oxidation bed for the control of CO emissions. Because natural gas is a clean-burning fuel, there would be inherently low amounts of sulfur formed as a result of the combustion process. Annual emissions rates for NO_x (2.5 ppm) and CO (2.0 ppm) were proposed. Anhydrous ammonia would be used in the SCR control system and some unreacted ammonia would exit the facility stack as ammonia "slip." However, this ammonia slip would be limited to 5 ppm.

A cooling water system would condense the steam coming from the steam turbine. Cooling water would itself be cooled within the multi-cell cooling tower. The cooling towers would be designed with an efficient drift elimination system to minimize the formation of PM_{10}. In a mechanical-drift cooling tower there is always a certain amount of water in the form of mist (drift) containing dissolved solids that would exit through the cooling tower stacks. As the drift evaporates, the dissolved solids would form particulate, thereby adding to the PM_{10} emissions. Typically, cooling towers are designed to maintain a drift at 0.008 % of the amount of circulating water flow. The proposed project would incorporate ultra-low drift elimination devices in the cooling towers, which would maintain drift at a level of 0.001% of the amount of circulating water flow. Only a portion of the drift is particulate matter; the remainder is water, which evaporates.

The features listed below, which are incorporated into the proposed cogeneration facility, represent BACT:

- Dry low NO_x combustion technology on the combustion gas turbines which limits NO_x and CO emissions from the combustion gas turbines to 9.0 ppm,
- SCR technology incorporated in the HRSGs that further reduces total NO_x emissions to a 2.5 ppmdv basis, and
- Oxidation catalyst controls incorporated into the HRSGs that reduce CO emissions to 2.0 ppmdv and VOCs reduced by approximately 30% with the application of the CO oxidation catalyst.

Emissions of Criteria Pollutants

The combustion turbine is an internal combustion turbine with emissions varying with ambient temperature and load condition. Because turbine operating parameters are directly affected by the ambient temperature, the ambient temperatures of 5°F, 50°F, and 85°F are considered in the emission calculations. These temperatures are chosen to represent one winter condition (5°F), an annual average condition (50°F), and one hot summer condition (85°F). Turbine emissions are higher at lower ambient temperatures. For each of these temperatures, three load conditions are considered: 100 (baseload), 75, and 50% load. For purposes of establishing the PSD permit emission limits, it is conservatively assumed that the gas turbines will operate 24 hours per day, 7 days per week.

The proposed emission units for the cogeneration facility are as follows:

- Three General Electric Frame 7FA combustion turbines (approximately 1,614 MBtu/hour lower heating value for each turbine at 50°F and baseload conditions),
- One diesel-driven emergency generator, about 1,500 kW in size,
- One diesel-driven firewater pump, about 265 horse power in size, and
- One multi-cell cooling tower.

The following operating scenario was considered as resulting in maximum emissions, and was used as the basis for the proposed permit limits:

- Baseload on natural gas with duct burners operating on natural gas at a maximum rate for up to 7,960 hours per year, 50% load for up to 300 hours per year, and 100 hot starts per turbine and shutdowns with the remaining hours offline.
- A mixture of partial load and baseload turbine operations (between 50% and baseload) could occur for up to 8,760 hours per year. Emissions for partial loads are less than those at baseload.
- An emergency diesel generator operating for testing and maintenance purposes for approximately two hours a week on any given day and up to a maximum of 250 hours per year.
- A firewater pump operating for testing and maintenance purposes for approximately two hours a week on any given day and up to a maximum of 250 hours per year.
- A cooling tower (PM_{10} only) operating at peak capacity 24 hours per day, 7 days per week, 52 weeks per year.

Hourly criteria pollutant emission rates from auxiliary equipment such as the cooling tower, emergency diesel generator, and the emergency firewater pump are shown in Table 3.2-6. Annual maximum potential emissions from the cogeneration facility and the auxiliary equipment are shown in Table 3.2-7.

Table 3.2-6: Hourly Criteria Pollutant Emission Rates – Auxiliary Equipment

Operating Unit	Hourly Emissions (lbs/hr)				
	NO_X	CO	VOC	PM_{10}	SO_2
Emergency generator	27.5	6.9	1.3	0.7	0.80
Firewater pump	3.33	0.17	0.14	0.05	0.105
Cooling tower	NE	NE	NE	1.63	NE

Source: BP 2002
NE = no emissions

Table 3.2-7: Annual Maximum Potential Criteria Pollutant Emissions

Operating Unit	Annual Emissions (tons/year)				
	NO_X	CO	VOC	PM_{10}	SO_2
Cogeneration facility turbines	229.4	156.8	42.2	254.4	50.9
Emergency generator	3.4	0.9	0.16	0.09	0.0995
Firewater pump	0.42	0.021	0.018	0.006	0.0131
Cooling tower	NE	NE	NE	7.1	NE
Total	233.3	157.7	42.3	261.6	51.0

Source: BP 2002
NE = no emissions
Note: Totals may not equal sum of individual components due to rounding. Refinery emissions reductions are excluded.

PSD Air Quality Impact Assessment

For purposes of the PSD assessments described below, emissions for the cogeneration facility were considered without taking into account any emission reductions that would occur at the refinery following removal of existing steam boilers.

PSD regulations require an assessment of the project's impact 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 water bodies; and effects associated with secondary aerosol formation. These requirements provide special protection for Class I areas.

Class I areas within a 124-mile radius of the project site include: North Cascades National Park, Olympic National Park, Glacier Peak Wilderness Area, Alpine Lakes Wilderness Area, and Pasayten Wilderness Area. The Mt. Baker Wilderness area was also included for informational purposes, even though it is not afforded special protection under the Clean Air Act.

PSD Class II Increment Consumption Analysis

Table 3.2-8 summarizes the maximum concentrations resulting from the cogeneration facility, and locations where these maxima were reached. Except for the annual SO_2 concentration, all locations are in Whatcom County within 1-mile (or closer) of the site.

Table 3.2-8: Maximum Concentrations [1]

Pollutant	Averaging Period	Conc. ($\mu g/m^3$)	Location
SO_2	Annual	0.03	7.5-miles north of project on the US/Canada border
SO_2	24-hour	1.0	328-feet north of the project site
SO_2	3-hour	5.0	Eastern boundary of the project site
SO_2	1-hour	8.7	Eastern boundary of the project site
PM_{10}	Annual	0.25	1 mile north of the project site
PM_{10}	24-hour	4.3	328 feet north of the project site
$PM_{2.5}$	Annual	0.25	1 mile north of the project site
$PM_{2.5}$	24-hour	4.3	328 feet north of the project site
CO	8-hour	12.6	Eastern boundary of the project site
CO	1-hour	67.3	Eastern boundary of the project site
NO_x	Annual	0.60	Northern boundary of the project site

1 Not including pollutant background concentrations

The maximum modeled concentrations of SO_2, NO_2, CO, and PM_{10} are below the respective SILs (Table 3.2-9). Proposed project generation of these pollutants has an insignificant impact on Class II increments, so further analysis is not required. In fact, Table 3.2-11 demonstrates that emissions combined with background concentrations are anticipated to be below the most stringent regulation for each criteria pollutant analyzed. The project would comply with the PSD Class II increment limits.

Local Air Quality Impact Assessment

The assessment of impacts on local and regional ambient air quality from the proposed facility was conducted using EPA-approved air quality dispersion models. These models are based on fundamental mathematical descriptions of atmospheric processes in which a pollutant source can be related to a receptor area. These models evaluated compliance with state and federal ambient air quality standards; SILs; and Class II area increments for NO_2 and SO_2. The regional impact assessment evaluated potential impacts on Class I areas within about 124 miles of the project site, including impacts on visibility, Class I increments for NO_2, SO_2, and PM_{10}, and impacts on soil and vegetation from deposition of nitrogen and sulfur compounds.

The Industrial Source Complex Prime (ISC Prime) dispersion model was used. Modeling analysis revealed that the project would not significantly affect the ambient air quality of the area, nor would it have a significant effect on Class II areas. Table 3.2-9 compares maximum concentrations to the PSD SIL.

Table 3.2-9: Significant Impact Level Modeling Analysis Results – U.S. Class II Areas [1]

Pollutant	Averaging Period	Maximum Concentration[2,3] ($\mu g/m^3$)	SIL[4] ($\mu g/m^3$)
Sulfur dioxide	Annual[5,7]	0.03	1
	24-hour[6,8]	1.0	5
	3-hour[6,8]	5.0	25
Inhalable particulate (PM_{10})[3]	Annual[7]	0.25	1
	24-hour	4.3	5
Carbon monoxide	8-hour[8]	12.6	500
	1-hour[8]	67.3	2,000
Nitrogen dioxide	Annual[7]	0.60	1

1 All other areas that are not designated as Class I within the State of Washington.
2 Highest of all cases for 1995, 1996, 1998, 1999, 2000.
3 Excludes the effect of refinery emission reductions.
4 Significant impact level for criteria pollutants.
5 Value represents a maximum sulfur content in natural gas of 0.8 gr/100 standard cubic feet annual average.
6 Value represents a maximum sulfur content in natural gas of 1.6 gr/100 standard cubic feet.
7 Based on annual average ambient temperature of 50°F.
8 From emergency use of the diesel generator.

Table 3.2-10 shows the results of the long-term criteria pollutant modeling. The maximum long-term (annual average) ground-level concentrations for criteria pollutants (NO_2, SO_2, and PM_{10}) were modeled using the ISC Prime model. All concentrations are below their respective Class I area SIL. Because all modeled impacts are below their respective Class I and Class II area SILs, no further dispersion modeling is required to demonstrate compliance with air quality standards and PSD increments.

Background concentrations are the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring stations. The predicted concentrations are added to the maximum background concentrations and compared to the most stringent NAAQS or the WAAQS shown in Table 3.2-1. Table 3.2-11 shows that the total concentration (modeled concentration plus background concentration) is significantly less than the most stringent standard for all pollutants analyzed.

Table 3.2-10: Significant Impact Level and Modeling Analysis Results - Class I Areas [1]

Pollutant	Averaging Period	Maximum Concentration[2,3] ($\mu g/m^3$)	SIL [4] ($\mu g/m^3$)
Sulfur dioxide	Annual	0.001	0.1
	24-hour	0.021	0.2
	3-hour	0.048	1
PM_{10}	Annual	0.0054	0.2
	24-hour	0.087	0.3
Nitrogen dioxide	Annual	0.0053	0.1

1 Class I areas include North Cascades National Park, Olympic National Park, Glacier Peak Wilderness, Alpine Lakes Wilderness, and Pasayten Wilderness Area.
2 Highest of 1995, 1996, 1998, 1999, 2000.
3 Excludes the effect of refinery emissions reductions.
4 Significant impact level for criteria pollutants.

Table 3.2-11: Comparison with Ambient Air Quality Standards

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)			Most Stringent of WAAQS or NAAQS ($\mu g/m^3$)
		Modeled	Background	Total	
SO_2	Annual	0.03	3	3	52
	24-hour	1.0	13	14	262
	3-hour	5.1	27	32	1,300
	1-hour	8.7	35	44	1,050
PM_{10}	Annual	0.25	13	13	50
	24-hour	4.3	35	39	150
$PM_{2.5}$	Annual	0.25	9	9	15
	24-hour	4.3	29	33	65
CO	8-hour	12.6	2,668	2,681	10,000
	1-hour	67.3	2,900	2,967	40,000
NO_2	Annual	0.60	27	28	100

Source: BP 2002
Notes: Excludes the effect of refinery emissions reductions.
All PM_{10} was conservatively assumed to be $PM_{2.5}$.

Pollutant Concentration Effects on Soils and Vegetation

Federal land managers (National Park Service, U.S. Fish and Wildlife, and U.S. Forest Service) have the responsibility of ensuring AQRVs in Class I areas are not adversely affected, regardless of whether the Class I increments are maintained. In order to protect plant species, the U.S. Forest Service recommends that maximum SO_2 concentrations not exceed 40 to 50 parts per billion (ppb) (105 to 130 $\mu g/m^3$), and annual SO_2 concentrations should not exceed 8 to 12 ppb (21 to 31 $\mu g/m^3$). For emissions of NO_2 (assuming a full conversion from NO_x), potential plant damage would not begin to occur with 24-hour concentrations less than 15 ppb (28 $\mu g/m^3$). Also, the modeling results show that the annual maximum concentration of NO_2 is 0.0053 $\mu g/m^3$, which is well below the SIL of 0.1 $\mu g/m^3$. Based on the results of the dispersion modeling analyses, facility emissions are expected to have a negligible effect on soils and vegetation. The proposed project would only combust low-sulfur natural gas fuel, thus minimizing the emission of sulfur compounds.

Nitrogen and Sulfur Deposition at Class I Areas

The CALPUFF modeling system was used to estimate the cogeneration facility’s potential contribution to total nitrogen and sulfur deposition in Class I areas. Soil, vegetation, and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition.

A change in visibility of greater than 5% is the threshold (level of concern) used by federal land managers to signify that additional analysis may be needed to more fully understand the overall impacts on visibility. The results of the dispersion modeling for visibility impacts are summarized in Table 3.2-12. Without the reduced emissions associated with decommissioning the refinery boilers, the CALPUFF modeling results show that the maximum change in visibility in a Class I area is 6.0%. The maximum visibility change modeled is in Olympic National Park. Only one day per year was above 5% in all of the modeled Class I areas.

Table 3.2-12: Air Quality Modeling Results

Operating Scenario	Class I area	Maximum Nitrogen Deposition (g/ha/yr)	Maximum Sulfur Deposition (g/ha/yr)	Maximum Visibility Change (%)	Number of Days over 5%	Visibility Change when Subtracting Boiler Emission Reductions
Normal operation without duct burners operating	Olympic National Park	0.09	0.11	5.5	1	1.6
	North Cascades National Park	0.44	0.31	2.5	0	1.4
	Alpine Lakes Wilderness	0.56	0.68	3.8	0	1.9
	Glacier Peak Wilderness Area	0.42	0.32	4.1	0	1.8
	Pasayten Wilderness Area	0.23	0.13	1.7	0	1.0
	Mt. Baker Wilderness Area	0.63	0.56	4.0	0	2.2
Normal operation with duct burners	Olympic National Park	0.09	0.11	5.6	1	1.7
	North Cascades National Park	0.45	0.31	2.5	0	1.4
	Alpine Lakes Wilderness Area	0.57	0.70	3.9	0	2.0
	Glacier Peak Wilderness Area	0.42	0.32	4.2	0	1.9
	Pasayten Wilderness Area	0.23	0.13	1.7	0	1.1
	Mt. Baker Wilderness Area	0.64	0.57	4.0	0	2.3
Operation with duct burners firing at a maximum rate	Olympic National Park	0.09	0.12	6.0	1	1.9
	North Cascades National Park	0.47	0.32	2.6	0	1.5
	Alpine Lakes Wilderness Area	0.60	0.73	4.1	0	2.3
	Glacier Peak Wilderness Area	0.44	0.34	4.4	0	2.1
	Pasayten Wilderness Area	0.24	0.14	1.8	0	1.2
	Mt. Baker Wilderness Area	0.67	0.60	4.1	0	2.3
Maximum		0.67	0.73	6.0	1	2.3

Notes: Significance level for visibility change is 5%.
Significance level for deposition is 5 g/ha/yr.

Regional Haze Assessment

Regional haze is usually quantified using two related indicators. First, the "visual range" is the distance at which a dark mountain is just perceptible against the sky. The visual range decreases if the air is polluted. Secondly, the "light extinction coefficient" is used to quantify how pollutants in the atmosphere reduce visual range. Increased light extinction reduces the visual range. According to federal land managers responsible for protecting air quality in Class I areas, a 5% change in extinction can be used to indicate a "just perceptible" change to landscape and a 10% change in extinction coefficient from the "natural" background is considered a significant incremental impact. Section 3.2.6, Secondary and Cumulative Impacts, contains a more in-depth discussion.

Secondary Particulate

Secondary particulate is formed when a portion of the gaseous NO_2 and SO_x emitted from the stack combine with ammonia to form particles of ammonium nitrate and ammonium sulfate. Atmospheric reactions that convert these compounds to secondary particulate take place outside of the exhaust stack hours to days after the NO_x and SO_x have been emitted from the project. The reactions are controlled by many complex factors, including time since release, temperature, humidity, sunlight, the concentration of the reactants in the atmosphere, and the extent to which atmospheric mixing occurs. For these reasons, secondary particulate is generally formed far away from the source of the pollutants.

Emissions of secondary particulate are included in the analyses of compliance with applicable ambient air quality standards and objectives above. The data presented are based on estimates performed with the ISC Prime model and include primary and secondary particulate by adding 20% of the sulfur emissions to the particulate matter emissions, thereby representing a worst-case scenario. Isopleths of the PM data are presented in Appendix B (see Exhibit 22.1, Page 5 and Exhibit 22.1, Page 6) for annual and 24-hour concentrations, respectively. Additional long range modeling of particulate matter impacts, including primary and secondary particulate, but excluding any reductions due to refinery boiler removal, was performed using the CALPUFF model for the annual averaging time. The representative isopleths are shown in Appendix B of this Final EIS.

<u>Toxic Air Pollutant Emission Rates</u>

For purposes of the regulatory Toxic Air Pollutant assessments described below, emissions for the cogeneration facility were considered excluding any emission reductions that would occur at the refinery following removal of existing steam generation boilers.

This section presents the emission factors and emission rates used in the analysis of toxic air pollutants. The proposed project has the potential to emit small quantities of toxic air pollutants regulated by Ecology. Formaldehyde, benzene, and other organic compounds associated with the combustion of fossil fuels would be released. In addition, post-combustion control with SCR results in ammonia emissions or "slip" that passes through the treatment process unreacted or chemically altered. Ammonia is not a federal hazardous air pollutant, but it is identified as a

Washington State Toxic Air Pollutant and along with sulfuric acid would be the highest noncriteria pollutant concentration emitted from the proposed project.

Emissions of toxic air pollutants would result from the combustion of natural gas in the gas turbines, HRSG duct burners, and auxiliary boiler, as well as from the use of the emergency diesel generator and diesel fire pump. Emissions were computed for short term emission rates, and the hourly fuel use of heat input was used to estimate emissions on a pounds per hour basis. For the annual average emission rates (tons per year), total annual fuel use or heat inputs were computed and used with the emission factors in estimating the emissions.

Ammonia emissions are based on a 5 ppmdv slip associated with the use of SCR for NO_x control. Sulfuric acid mist emissions depend on the amount of sulfur in the fuel and amount of sulfur dioxide converted to sulfur trioxide.

The toxic air pollutants and their pollutant class, emission factors, and emission rates for the gas turbines, the emergency diesel generator, and the diesel fire pump are listed in Table 3.2-13. The toxic air pollutant classes refer to Class A, for annual-averaged risk-based carcinogens, and Class B for non-carcinogens.

The proposed project would adopt BACT for toxics for controlling toxic emissions pursuant to Chapter 173-460-040 WAC, including the following:

- Use of clean natural gas as the only fuel for the combustion gas turbines and HRSG duct burners which help minimize formation of toxics, and
- Use of an oxidation catalyst unit on each HRSG duct burner that would reduce the emissions of certain volatile organic toxic compounds.

Modeling Criteria

Air quality dispersion modeling was used to assess compliance with the State of Washington’s toxic air pollutant regulations (Chapter 173-460 WAC). Those toxic air pollutants that are emitted in quantities above the Small Quantity Emissions Rate (SQER) require calculation of potential impacts that are then compared with the Acceptable Source Impact Levels (ASILs) to assess compliance. Seventeen compounds were identified as being emitted in amounts greater than the small quantity emission rate and required modeling. Depending on the compound, either the 24-hour or annual average concentrations were used for comparison with the ASILs.

Table 3.2-13: Toxic Compounds that Require Modeling

Toxic Compound	Emission Rate for 3 Comb. Turbines (lbs/hr)	Emission Rate for Emergency Generator (lbs/hr)	Emission Rate for Firewater Pump (lbs/hr)	Total Annual Emissions (lbs/yr)	Total Hourly Emissions (lbs/hr)	SQER (lbs/yr)	SQER (lbs/hr)	ASIL ($\mu g/m^3$)	Class A or B Toxic Compound	Averaging Period
Acetaldehyde	0.0210	0.00039	0.001553	184.8	0.023	50	NA	0.45	A	Annual
Acrolein	0.0373	0.000121	0.0001872	327.1	0.038	175	0.02	0.02	B	24-hour
Ammonia[1]	39.5	0	0	346,247	39.5	17,500	2.0	100	B	24-hour
Benzene	0.0705	0.01192	0.001889	621.4	0.084	20	NA	0.12	A	Annual
1,3-Butadiene	0.0025	0	0.0000791	22.0	0.0026	0.5	NA	0.0036	A	Annual
Formaldehyde	0.5876	0.00121	0.00239	5,148	0.59	20	NA	0.077	A	Annual
PAH	0.0129	0.00326	0.000034	113.5	0.016	NA	NA	0.00048	A	Annual
Arsenic	0.000052	0.00371	0.000265	1.5	0.00403	NA	NA	0.00023	A	Annual
Beryllium	0.000003	0	0	0.03	0.000003	NA	NA	0.00042	A	Annual
Cadmium	0.000287	0.00035	0.000025	2.6	0.00066	NA	NA	0.00056	A	Annual
Chromium	0.0259	0.00371	0.000265	227.6	0.030	175	0.02	1.7	B	24-hour
Cobalt	0.0255	0	0	223.6	0.026	175	0.02	0.33	B	24-hour
Copper[1]	0.0257	0	0	225.3	0.026	175	0.02	0.3	B	24-hour
Manganese	0.0256	0	0	224.2	0.026	175	0.02	0.4	B	24-hour
Nickel	0.0260	0.00035	0.000025	228.3	0.026	0.5	NA	0.0021	A	Annual
Zinc[1]	0.0331	0.00385	0.000275	290.7	0.037	175	0.02	7	B	24-hour
Sulfuric Acid[1]	8.1	0.2437	0.0321	71,040	8.38	175	0.02	3.3	B	24-hour

Notes: SQER = Small Quantity Emission Rate
ASIL = Acceptable Source Impact Level
NA = Not Applicable
The results represent maximum emissions.
1 Not an EPA classified hazardous air pollutant.

Toxic Air Pollutant Analysis

The maximum modeled 24-hour and annual average toxic air pollutant concentrations resulting from the proposed facility emissions are compared to the appropriate Modeling was performed using the ISC Prime model. ASILs in Table 3.2-14. For all toxic air pollutants evaluated, the maximum modeled concentrations are less than the ASILs. Maximum short term ammonia and sulfuric acid mist concentrations are also below the 24-hour ASIL. Based on these modeling results, the proposed cogeneration facility is not expected to create any significant impacts due to its toxic air pollutant emissions.

Table 3.2-14: Significant Impact Level Modeling Analysis Results - Toxic Compounds

Pollutant	Maximum Predicted Concentration ($\mu g/m^3$)[4]		ASIL ($\mu g/m^3$)[3]	ASIL Exceeded
	Annual[1]	24-hr[2]		
Acetaldehyde	0.00014	NA	0.45	No
Acrolein	NA	0.0027	0.02	No
Ammonia	NA	2.8	100	No
Benzene	0.00032	NA	0.12	No
1,3-Butadiene	0.00001	NA	0.0036	No
Formaldehyde	0.00237	NA	0.077	No
PAH	0.00007	NA	0.00048	No
Arsenic	0.00007	NA	0.00023	No
Beryllium	<0.00001[5]	NA	0.00042	No
Cadmium	0.00001	NA	0.00056	No
Chromium	NA	0.0024	1.7	No
Cobalt	NA	0.0018	0.33	No
Copper	NA	0.0018	0.3	No
Manganese	NA	0.0018	0.4	No
Nickel	0.00011	NA	0.0021	No
Zinc	NA	0.0025	7	No
Sulfuric Acid	NA	0.57	3.3	No

1 Highest of cases (modeled operating scenarios) 1AB, 1BB, 1CB, 2B, 6B (50°F).
2 Highest of all cases (modeled operating scenarios) for 1995, 1996, 1998, 1999, and 2000.
3 Acceptable source impact levels.
4 Excludes the effect of refinery emissions reductions.
5 Impacts are less than the sensitivity of the ISC model of 0.00001 $\mu g/m^3$

Regional Air Quality Impact Assessment

Short Range Air Quality Impacts in Canada

Chemical concentration analyses for areas in Canada were conducted using methods similar to those used for Class II areas in the U.S., as previously described. These analyses excluded any emission reductions from the refinery resulting from the removal of refinery boilers.

The analyses covered an area into Canada extending 31-miles from the project site (the limit of the approved use of the ISC dispersion model), as shown in Figure 3.2-1. The predicted concentrations are added to the maximum background concentrations provided by Canadian regulatory agencies and compared to the Canadian objectives and standards presented in Table 3.2-15. The $PM_{2.5}$ emissions are not specifically modeled and are conservatively assumed to be equal to the PM_{10} emissions. In reality, the $PM_{2.5}$ emissions are a subset of the PM_{10} emissions and should, therefore, be lower than reported. The modeled maximum concentration is significantly less than the background concentration for all pollutants. The total concentration (modeled concentration plus background concentration) is significantly less than the objectives and standards (Table 3.2-2) for all pollutants.

Table 3.2-16 summarizes the chemical or pollutant concentrations resulting from the project alone (not including background) reached in Canada. The maximum concentrations in Canada were reached 7.5 to 7.8 miles north of the project site at the US/Canada border. As discussed above, the maximum modeled concentration (including background) occurs in the US, and is less than both the US standards and Canadian Objectives. Table 3.2-17 summarizes the concentrations estimated (including background) at the closest monitoring stations in Canada.

Table 3.2-15: Maximum Concentration Modeling Analysis in Canada

Pollutant	Averaging Period	Maximum Concentration in Canada (μg/m^3)			Most Stringent Canadian Objective or Standard (μg/m^3)
		Modeled	Background	Total	
SO_2	Annual	0.03	3	3	25
	24-hour	0.7	16	17	150
	3-hour	3.3	27	30	374
	1-hour	5.3	59	64	450
PM_{10}	Annual	0.2	13	13	30
	24-hour	2.5	35	38	50
$PM_{2.5}$ [1, 2]	24-hour	0.9	18	19	30
CO	8-hour	4.8	2,668	2,673	5,500
	1-hour	13.6	2,900	2,914	14,300
NO_2 [3]	Annual	0.2	27	27	60
	24-hour	1.6	69	71	200
	1-hour	16.7	107	124	400

Note: Excludes the effect of refinery emissions reductions.

1 $PM_{2.5}$ emissions are conservatively assumed to be equal to PM_{10} emissions; maximum $PM_{2.5}$ emissions are conservatively equal to 2.5 μg/m$^{3.}$

2 The $PM_{2.5}$ Canada-wide standard is based on the 98th percentile averaged over three years; therefore, the modeled and background values indicated above are also based on these assumptions.

3 NO_X is considered to be fully converted to NO_2.

Table 3.2-16: Maximum Concentrations in Canada

Pollutant	Averaging Period	Concentration (μg/m3)	Location
SO_2	Annual	0.03	7.5-miles north of project on the US/Canada border
SO_2	24-HR	0.7	7.5-miles north of project on the US/Canada border
SO_2	3-HR	3.3	7.5-miles north of project on the US/Canada border
SO_2	1-HR	5.3	7.5-miles north of project on the US/Canada border
PM_{10}	Annual	0.2	7.5-miles north of project on the US/Canada border

Table 3.2-16: Continued

Pollutant	Averaging Period	Concentration (μg/m3)	Location
PM_{10}	24-HR	2.5	7.5-miles north of project on the US/Canada border
$PM_{2.5}$	24-HR	0.9	7.5-miles north of project on the US/Canada border
CO	8-HR	4.8	7.8-miles north of project on the US/Canada border
CO	1-HR	13.6	7.5-miles north of project on the US/Canada border
NO_x	Annual	0.2	7.5-miles north of project on the US/Canada border
NO_x	24-HR	1.6	7.5-miles north of project on the US/Canada border
NO_x	1-HR	16.7	7.5-miles north of project on the US/Canada border

Table 3.2-17: Ambient Air Monitors Closest to Project Site

Pollutant	Averaging Period	Concentration (μg/m3)	Background Concentration (μg/m3)	Total Concentration (μg/m3)	Objective[1] (μg/m3)
Concentrations at Surrey					
PM_{10}	Annual	0.05	13	13.0	30
PM_{10}	24-HR	0.50	39	39.5	50
NO_x	Annual	0.04	27	27.0	60
NO_x	24-HR	0.42	69	69.4	200
NO_x	1-HR	8.2	107	115	400
CO	8-HR	1.1	2436	2437	5500
CO	1-HR	3.6	2900	2904	14300
Concentrations at Langley[2]					
PM_{10}	Annual	0.04	13	13.0	30
PM_{10}	24-HR	0.36	37	37.4	50
$PM_{2.5}$[2]	24-HR	0.36	16	16.4	30
NO_x	Annual	0.03	20	20.0	60
NO_x	24-HR	0.33	52	52.3	200
NO_x	1-HR	7.8	92	100	400
CO	8-HR	0.7	2668	2669	5500
CO	1-HR	3.6	4060	4064	14300
Closest SO_2 monitors in Canada – Concentrations at Richmond					
SO_2	Annual	0.003	3	3.0	25
SO_2	24-HR	0.08	13	13.1	150
SO_2	3-HR	0.34	27	27.3	374
SO_2	1-HR	0.90	35	35.9	450
Concentrations at Abbotsford					
SO_2	Annual	0.0014	3	3.0	25
SO_2	24-HR	0.058	8	8.1	150
SO_2	3-HR	0.35	21	21.3	374
SO_2	1-HR	1.04	29	30.0	450
$PM_{2.5}$ Ambient Air Monitors Closest to Project Site – Concentrations at Pitt Meadows[3]					
$PM_{2.5}$	Annual	0.029	9	9.0	NA
$PM_{2.5}$	24-HR	0.30	19	19.3	30
Concentrations at Vancouver Airport					
$PM_{2.5}$	Annual	0.016	9	9.0	NA
$PM_{2.5}$	24-HR	0.17	18	18.2	30

1 Most Stringent Canadian Objective or Standard
2 A $PM_{2.5}$ monitor was added at Langley in 2002.
3 $PM_{2.5}$ background and total concentration are based on the 98th percentile

Air Quality Visibility Analysis in Canada

The visibility analyses for Canadian areas were conducted using methods similar to those used for Class I areas in the U.S., and excluded any effects of refinery emission reductions. The analyses were conducted along seven lines of sight recommended by the GVRD (listed in Table 3.2-18). The visibility extinction was averaged along each line of sight to achieve a day-by-day account of whether visibility is impaired with and without the impacts from the proposed project. The maximum visibility change because of emissions from the proposed project was also calculated.

The results of the Canada visibility analyses are summarized in Table 3.2-19. A visual range of less than 37 miles was used to determine impaired visibility. As shown in this table, impacts from the proposed project would not increase the number of days with impaired visibility at any of the seven specified lines of sight. A visibility analysis threshold has not been established by Canadian agencies. For purposes of this analysis, the threshold established by the U.S. federal land managers was used. According to the federal land managers, a greater than 5% change in visibility will evoke a noticeable change in most landscapes. The results of the visibility analysis in Canada show that the maximum visibility change is only 2.7%, which is significantly below the 5% threshold.

Table 3.2-18: Lines of Sight Evaluated for Visibility Analysis in Canada

Line of Sight	Observer Location	Direction and Target
1	Victoria	East-northeast to Mount Baker
2	White Rock	East-southeast to Mount Baker
3	Delta	East-southeast to Mount Baker
4	Vancouver	North to North Shore Mountains (The Lions)
5	Langley	North to North Shore Mountains (Golden Ears)
6	Chilliwack	East to Mount Cheam
7	Abbotsford	Southeast to Mount Baker

Table 3.2-19: Results of Visibility Analysis in Canada

Line of Sight	Number of Days with Impaired Visibility, Background Conditions[1]	Additional Days with Impaired Visibility from Cogeneration Facility	Maximum Visibility Change
1	171	0	1.2%
2	166	0	2.4%
3	166	0	2.1%
4	166	0	2.2%
5	166	0	2.7%
6	166	0	1.5%
7	166	0	1.4%

1 Impaired visibility is defined as those days with a visibility range of less than 37-miles. Excludes the effect of refinery emissions reductions.

Regional Impacts of Concurrent Emissions Reductions at the Refinery

State regulatory air permitting requirements require that the maximum potential emissions expected from the cogeneration facility be used for permitting purposes. The analyses presented above are based on the maximum potential emissions. However, in order to characterize a scenario of more probable long range impacts to the region, the Applicant has estimated what the actual emissions from the cogeneration facility are likely to be. This estimate is based on the following assumptions, described in more detail below:

- Refinery emissions would decrease because of the removal of existing utility boilers that would no longer be needed once steam was purchased from the cogeneration facility;
- A more realistic actual operating scenario would lead to actual emissions lower than the maximum potential emissions required by regulatory analyses;
- Actual particulate emissions would be lower than those measured at the stacks by the required EPA reference methods; and
- Recent information indicates that long range secondary particulate formation would be reduced due to NO_x emission reductions at the refinery.

The overall primary emission reductions estimated by the Applicant are summarized in Table 3.2-20. As noted above, the estimated reductions were not used to determine the air quality impacts of the project. As stated earlier in Section 3.2, project emissions, excluding any reductions from removal of the refinery boilers or any other adjustments listed above, do not violate ambient air quality standards or objectives in the U.S. or in Canada.

Table 3.2-20: Overall Primary Emission Reductions Estimated by the Applicant

Expected Annual Reductions (tpy)	NO_x	CO	VOC	PM_{10}	SO_2
Maximum Potential Emissions from Project	233.3	157.7	42.3	261.6	51.0
Estimated Actual Emissions from the Cogeneration Facility	181	81	28	242.4	50
Refinery Emission Reductions Through Utility Boiler Removal	-499	-54	-3	-10	-7
PM_{10} Adjustment due to Test Method	--	--	--	-148.5	--
Net Regional Change in Primary Emissions	-318	27	25	84	43

Source: BP 2002

Estimate of Actual Emissions from the Cogeneration Facility

The data in Table 3.2-7 reflect the maximum potential emissions expected from the cogeneration facility, based on the regulatory requirements of PSD and NSR review. The Applicant has also prepared an estimate of the actual cogeneration facility emissions, shown in Table 3.2-21. This estimate is based on several assumptions. First, the Applicant used an average operating scenario based on six years of expected operation (a typical operational/maintenance cycle for turbines) while taking into account market conditions and required maintenance. Under this average operating scenario, the cogeneration facility is expected to operate as follows:

- 55% of the time at 100% turbine load and no duct firing.
- 39% of the time at 100% turbine load and variable duct burner firing sufficient to maintain the refinery steam header pressure.
- 2% of the time in a forced outage where one turbine is down for maintenance for eight hours while the other two are operating at 100% turbine load.
- 1% of the time in an economic dispatch mode where all three turbines are down for eight hours.
- 3% of the time in a planned outage where turbines would be shut down for more than 72 hours for planned maintenance.

Second, the Applicant assumed that average actual NO_x emissions would be no more than 90% of the proposed permit limit to ensure constant compliance with the short term permit limits. These types of facilities would expect to maintain average emissions somewhat below their permit limits. Based on its operating experience, the Applicant indicated that it would be reasonable to expect actual NO_x emissions to average 10% below the permit limit.

Third, the Applicant assumed that average actual CO emissions would be no more than 80% of the proposed permit limit to ensure constant compliance with the short term permit limits. Because oxidation catalyst performance is more efficient when new and degrades over time, it is reasonable to expect that the CO concentration would be very low initially and increase over time. The long term average CO concentration would always be below the permit limit.

Table 3.2-21: Expected Annual Emissions (Criteria Pollutants)

Expected Annual Emissions (tons/year)	NO_X	CO	VOC	PM_{10}	SO_2
100% load with no duct firing	104.9	45.8	14.4	133.0	27.7
100% load with minimal duct firing	65.7	28.2	11.6	95.2	20.4
Forced outage	3.9	2.8	0.7	4.6	0.9
Economic dispatch	2.3	2.9	0.5	2.3	0.4
Planned outage	0.4	0.6	0.1	0.1	0.02
Emergency generator	3.44	0.86	0.16	0.09	0.10
Firewater pump	0.42	0.021	0.018	0.006	0.013
Cooling tower	NE	NE	NE	7.1	NE
Total (tons/year)	181.1	81.2	27.5	242.4	49.6

NE - no emissions

1 Approximately 60% of the PM_{10} emissions are subtracted due to source tests exaggerations of sulfates and the inclusion of compounds associated with background, ambient air.

Refinery Emission Reductions due to removal of Refinery Steam Boilers

Emissions of criteria pollutants from the proposed cogeneration facility would be offset by reductions in emissions from the refinery. These reductions would occur because the cogeneration facility would provide steam to the refinery, which would allow the refinery to discontinue the utility boilers currently in use. This would also allow the refinery to reduce its use of gas-fired heaters. Table 3.2-22 summarizes the possible refinery emission reductions if steam produced by the cogeneration project replaces steam currently produced by refinery boilers. A consequence of cogeneration is the reduction in steam production inside the refinery and an associated reduction in the criteria pollutant emissions. All emission reductions are based on the reduction in steam production in the refinery. After the cogeneration project begins supplying steam to the refinery, the refinery utility boilers would be shut down and would no longer produce emissions. As shown in Table 3.2-20 above, removal of the refinery boilers would cause a net decrease in NO_x emissions.

It should be noted that new boilers are being planned for the Clean Fuels project (also known as the ISOM project) but they will be shut down when the cogeneration facility is operating. Some backup boiler capability would still be required at the refinery when the cogeneration facility is not operating.

Table 3.2-22: Refinery Emission Reductions

Expected Annual Reductions (tpy)	NO_x	CO	VOC	PM_{10}	SO_2
Refinery emission reductions	-499	-54	-3	-10	-7

Source: BP 2002

PM Emissions Adjustments due to Test Method

Finally, the Applicant assumed that the project's actual PM_{10} emissions would be approximately 60% below the proposed permit limit due to source test exaggeration of sulfates and the inclusion of compounds associated with background air. The Applicant based these assumptions on research that has been conducted in an effort to determine the source and type of the particulate matter in the exhaust gas and to determine whether the EPA test method is accurate (England and Wien 2002).

This research shows that up to 90% of the particulate reported by this test method (EPA Method PRE-4/202) in exhaust from natural gas-fueled combustion turbines is condensable particulate. Of this condensable particulate, about 90% is inorganic and comprised of sulfates, chlorides, ammonia, sodium, and calcium.

This research also shows that the EPA test method significantly exaggerates PM_{10} emissions. By far, the largest source of error in the EPA test method is generated by condensable particulate measured by the test. SO_2 gas, a constituent of the stack gas, is drawn into the test apparatus. As expected of a gas, SO_2 passes through the filterable portion of the test apparatus and into an ice water bath, where it is "bubbled" through the cold water. The SO_2 dissolves in the cold water. Since gas turbines operate with a large excess of oxygen, oxygen is also dissolved in the cold water. During the testing, virtually all of the SO_2 is slowly oxidized to form sulfate (SO_4), which is measured as a particulate. This results in the test method significantly overestimating the particulate emissions because, during normal operation, only a relatively small portion of the SO_2 in the exhaust would form SO_4 in the stack.

The test method also overstates the particulate emissions by including particulate already present in the ambient air. This particulate matter was identified in the research as sodium, chloride, and calcium.

The study concludes that the EPA test method suffers from measurement error due to the small amount of particulate sample collected from the gas turbine exhaust. The EPA method was intended to collect samples over a one-hour period, however, the research shows that gas turbine tests must be run for up to six hours to collect enough material.

Based on the information contained in the GE and Sierra Research studies, the actual particulate emissions from the facility are expected to be at least 60% less than the particulate emissions measured by the EPA reference method test. The resulting 40% adjustment (-148.5 tons per year) is indicated in Table 3.2-20.

As indicated above, the adjustments due to test method were not taken into account for regulatory purposes. The adjustments were considered to estimate the actual emission from the project. Regulatory compliance for the PM emissions would require monitoring and testing according to established EPA practice and regulations.

Secondary Particulate

The Applicant also considered the impact of removing refinery boilers on the secondary particulate in regional emissions balance. The projected annual emissions shown in Table 3.2-21 are based only on in-stack emission or primary emissions.

One to two days after leaving the stack, a portion of the NO_2 and SO_2 emitted from the stack as gas eventually combines with ammonia in the atmosphere to form particles of ammonium nitrate and ammonium sulfate. These newly formed compounds are called secondary particulate because they are formed in the atmosphere outside of the stack.

The amount of NO_2 and SO_2 converted to particulate is dependent on many of the atmospheric conditions listed above. In the following analysis, it was assumed that 33% of NO_2 is converted to ammonium nitrate and 20% of SO_2 is converted to ammonium sulfate. Although the conversion factors used for this analysis are consistent with the CALPUFF model conversion factors and published articles (Stockwell 2000), they represent the higher end of conversion estimates that could be achieved under low dispersion conditions when maximum impacts are expected to occur. Lower conversion rates would result in respectively lower amounts of secondary PM being formed from primary NO_x and SO_x emissions.

Areas of Whatcom County and lower Fraser Valley airsheds where secondary particulate is formed are already ammonia rich due to existing vegetation and agricultural practices. Modeling of secondary particulate formation using CALPUFF was performed assuming no limit on ammonia available to react with NO_x and SO_x emissions from the project. Therefore, additional ammonia emissions (slip) from the project would neither be a controlling factor on the formation of secondary particulate nor would they contribute to additional secondary particulate formation.

As shown in Table 3.2-23, changes in secondary particulate emissions would occur from two sources: first, NO_x and SO_2 emitted by the cogeneration facility would produce secondary particulate emissions; second, reductions of NO_x emissions from the refinery through removal of the utility boilers would lead to a reduction of refinery secondary particulate emissions. When both of these secondary particulate emission changes are taken into account, and if adjustments for PM_{10} test method are included, the proposed project would result in an overall regional reduction of particulate. The Applicant has also modeled the impacts on PM concentrations on a long range basis. Appendix B of this Final EIS (see Exhibit 22.2, page 1; Exhibit 22.2, page 2; and Exhibit 22.3) shows CALPUFF modeling results for PM_{10} considering maximum potential, or expected emissions, with and without refinery reductions. These modeled isopleths also include the formation of secondary particulate.

Inhalable PM includes fine and coarse particles from naturally occurring and man-made sources. Fine particles, such as those found in smoke and haze, are 2.5 micrometers in diameter or less. Coarse particles, such as those found in wind-blown dust, have diameters between 2.5 and 10 micrometers. Local and regional contributions of particulate matter include sea salt, pollen, smoke from forest fires and wood stoves, road dust, industrial emissions, and agricultural dust. Particles of this size are small enough to be drawn deep into the respiratory system where they can contribute to infection and reduced resistance to disease (Canadian Federal Government 2002).

Health risk associated with exposure to particulate matter varies throughout a lifetime, generally being higher in early childhood, lower in healthy adolescents and younger adults, and increasing in middle age through old age as the incidence of heart and lung disease and diabetes increases. People with existing heart or lung disease, older adults with undiagnosed heart and lung disease, and children are considered at greater risk from particles than other people, especially when they are physically active. Particles can aggravate heart or lung diseases—such as coronary artery disease, congestive heart failure, and asthma or chronic obstructive pulmonary disease. Many studies show that when particle levels are high, older adults are more likely to be hospitalized, and some may die of aggravated heart or lung disease. Children are likely at increased risk because their lungs are still developing and they spend more time at high activity levels. In addition, scientists are evaluating new studies that suggest exposure to high particle levels may be associated with low birth weight in infants, pre-term deliveries, and possibly fetal and infant deaths (EPA 2003).

Both long and short term exposures have been identified as leading to health effects. Long term exposures, such as those experienced by people living for many years in areas with high particle levels, have been associated with problems such as reduced lung function, the development of chronic bronchitis, and even premature death. Short term exposures to particles (hours or days) can aggravate lung disease, causing asthma attacks and acute bronchitis, and may also increase susceptibility to respiratory infections. In people with heart disease, short term exposures have been linked to heart attacks and arrhythmia. Healthy children and adults have not been reported to suffer serious effects from short term exposures, although they may experience temporary minor irritation when particle levels are elevated (EPA 2003)

A University of British Columbia researcher in 1995 estimated that increases in fine particulate pollution are a contributor to 82 premature deaths in British Columbia each year, 146 hospitalizations due to asthma, lung and heart disorders, and 354 extra emergency room visits for asthma, chronic bronchitis or emphysema (Canadian Federal Government 2002). Based on a more recent study of the air quality of the lower mainland, Medical Health Officers expressed the view that between 15 and 150 deaths per year may be attributable to air pollution (Canadian Federal Government 2002). In 2001, within the Fraser Valley smog exceeded the reference level about 4% of the time for fine airborne particulate matter (Canadian Federal Government 2002).

With respect to air quality in Whatcom County, the American Lung Association of Washington (2003) has reported that of 108 days when air quality data measurements were available in Whatcom County in 2002, 98 days were reported to have an EPA AQI of “good,” and 11 days had a “moderate” AQI . In 2004, of 363 days when measurements were available in Whatcom County, 350 days had a “good” AQI, and 13 days had a “moderate” AQI (American Lung Association of Washington 2004). The EPA AQI is a uniform index that provides general information to the public about air quality and associated health effects. For an AQI of “good” air quality is considered satisfactory, and air pollution poses little or no risk. For an AQI of “moderate,” air quality is acceptable, but some pollutants may pose a moderate health concern for a small number of people.

Table 3.2-23: Secondary Particulate Emission Balance

Annual Emissions (tons/yr)	Expected Primary PM_{10}	Secondary PM from NO_x	Secondary PM from SO_x	Overall PM
Case 1: Excluding PM_{10} Adjustment due to test method				
Total from Cogeneration	242.4	104	21	367
Refinery Emission Reductions through utility boiler removal	-10	-286	-3	-299
Changes in PM emissions from Cogen and removal of refinery boilers	232	-182	18	68
Case 2: Including PM_{10} adjustment due to test method				
Total from Cogeneration	93.9	104	21	218.9
Refinery Emission Reductions through utility boiler removal	-10	-286	-3	-299
Changes in PM emissions from Cogen and removal of refinery boilers	83.9	-182	18	-80.1

Source: BP 2002, GVRD 2003
Note: These balances assume that molecular weight change occurs upon formation of secondary particulate matter.

Impacts on Class I Visibility Analyses from Refinery Emission Reductions

The Applicant performed additional modeling for the Class I visibility analysis to account for some of the reduction in emissions resulting from removal of the utility boilers at the refinery. The results of this revised dispersion modeling for visibility impacts are summarized in Table 3.2-24. The maximum visibility change, when subtracting the emissions for the three utility boilers, is 2.3%, and the number of days of impact to the Olympic Regional Park is reduced to zero.

Table 3.2-24: Air Quality Related Values Modeling Analysis Results Including Refinery Emissions Reductions

Operating Scenario	Class I area	Visibility Change when Subtracting Boiler Emission Reductions	Number of Days over 5%
Normal operation without duct burners operating	Olympic National Park	1.6	0
	North Cascades National Park	1.4	0
	Alpine Lakes Wilderness Area	1.9	0
	Glacier Peak Wilderness Area	1.8	0
	Pasayten Wilderness Area	1.0	0
	Mt. Baker Wilderness Area	2.2	0
Normal operation with duct burners	Olympic National Park	1.7	0
	North Cascades National Park	1.4	0
	Alpine Lakes Wilderness Area	2.0	0
	Glacier Peak Wilderness Area	1.9	0
	Pasayten Wilderness Area	1.1	0
	Mt. Baker Wilderness Area	2.3	0
Operation with duct burners firing at a maximum rate	Olympic National Park	1.9	0
	North Cascades National Park	1.5	0
	Alpine Lakes Wilderness Area	2.3	0
	Glacier Peak Wilderness Area	2.1	0
	Pasayten Wilderness Area	1.2	0
	Mt. Baker Wilderness Area	2.3	0
Maximum		2.3	0

Notes: Significance level for visibility change is 5%.
Significance level for deposition is 5 g/ha/yr.

Emissions during Startup and Shutdown

Combustion turbine startup is defined as any operating period that is ramping up from less than partial load. Partial load is when the turbine is operating at less than 60% of turbine power generation capacity. Startup ends when normal temperatures have been reached in both the catalytic oxidation and selective catalytic reduction modules. Normal operating temperatures for these two catalyst systems are recommended by the catalyst system manufacturer. Shutdown starts when ramping down from normal operation (between 60% and 100% turbine power generation capacity), and ends when fuel flow ends.

Startups are classified into three types: hot starts, warm starts, and cold starts. Hot starts occur less than eight hours after the turbine has been shut down. Warm starts occur when the turbine is restarted after being shut down for 8 to 72 hours. Cold starts occur when the turbine is restarted after being shut down for more than 72 hours.

An integrated microprocessor-based control system would be provided for the turbine equipment, data acquisition, and data analysis. The control system would be used for startup, shutdown, monitoring and control of emissions, and protection of personnel and equipment. This assures that the turbine startups and shutdowns are carefully done to be safe, protect the equipment from damage, and minimize emissions. The startup procedure for a three turbine power block is staged, where the first turbine started heats the second and third turbine's equipment, effectively shortening the total startup time.

The turbine manufacturer, General Electric, provided estimates of emissions during startup and shutdown. NO_X, CO, and VOC emissions increase during startup because the low NO_X turbine burners take time to stage into low NO_X operating mode, and because the SCR and oxidation catalysts are not up to operating temperature yet. PM_{10} and SO_2 emissions are proportional to fuel flow, not combustion conditions, so their emission rate does not increase above permitted levels.

For purposes of development of the PSD air emissions permit, startup and shutdown emissions were estimated by assuming 100 hot starts and 100 shutdowns per year. Table 3.2-25 summarizes the emissions during each startup. The short term (hourly and 24-hour average) and long term (12-month rolling average) emissions during startup and shutdown were modeled using ISC Prime. Hot and cold start scenarios were considered (warm starts would have less impact than hot and cold starts). Tables 3.2-26 and 3.2-27 show the short term maximum modeled impacts in the U.S. and Canada resulting from startups.

Startup and shutdown emissions would also be measured and counted toward the project total annual emissions. NO_X and CO continuous emission monitors would be operational during startups and shutdowns to measure emissions. The NO_X and CO annual limits effectively limit the number of startups and shutdowns to the emissions modeled in the application. Impacts were well below any air quality standard.

Table 3.2-25: Emissions during Startup (lbs/event)

Emission	Hot Start	Warm Start	Cold Start	Shutdown
1st Turbine				
Duration (min.)	60	112	187	30
NOx	88	173	257	19
CO	287	420	490	114
PM_{10}	13	28	49	5
SO_2	2	4	8	1
VOC	24	53	94	13
2nd Turbine				
Duration (min.)	45	67	97	30
NO_x	84	109	175	19
CO	351	454	733	114
PM_{10}	9	15	23	5
SO_2	1	3	4	1
VOC	15	27	43	13
3rd Turbine				
Duration (min.)	45	72	102	30
NO_x	84	119	184	19
CO	351	477	752	114
PM_{10}	9	16	25	5
SO_2	1	3	4	1
VOC	15	30	48	13

Table 3.2-25: Continued

Emission	Hot Start	Warm Start	Cold Start	Shutdown
Total				
Duration (min.)	105	192	307	30
NO_x	256	401	616	19
CO	989	1351	1975	114
PM_{10}	30	58	97	5
SO_2	5	10	16	1
VOC	55	110	184	13

Source: Brian Phillips, Prefiled Testimony, Exhibit 22

Table 3.2-26: Maximum Modeled Impacts in the U.S. from Startup

Pollutant	Averaging Period	Maximum Concentration (µg/m^3)			Lower of WAAQS or NAAQS (µg/m^3)
		Modeled	Background	Total	
SO_2	24-hour	0.6	13	14	262
	3-hour	3.2	27	30	1,300
	1-hour	4.1	35	39	1,050
PM_{10}	24-hour	1.6	35	37	150
$PM_{2.5}$	24-hour	1.6	29	31	65
CO	8-hour	47	2,668	2,715	10,000
	1-hour	584	2,900	3,484	40,000

Source: Brian Phillips, Prefiled Testimony, Exhibit 22

Notes: Background concentration is the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring stations (see Application for Site Certification Tables 3.2-8 and 3.2-9).
In the U.S., there is no short term (24-hour or 1 hour) NAAQS for NO_2. Excludes the effect of refinery emissions reductions.

Table 3.2-27: Maximum Modeled Impacts in Canada from Startup

Pollutant	Averaging Period	Maximum Concentration (µg/m^3)			Most Stringent Canadian Objective or Standard (µg/m^3)
		Modeled	Background	Total	
SO_2	24-hour	0.6	16	17	150
	3-hour	2.5	27	30	374
	1-hour	3.3	59	62	450
PM_{10}	24-hour	1.5	35	37	50
$PM_{2.5}$	24-hour	1.5	18	20	30
CO	8-hour	27	2,668	2,695	5,500
	1-hour	340	2,900	3,240	14,300
NO_2	24-hour	2.0	69	71	200
	1-hour	87.4	107	194	400

Source: Brian Phillips, Prefiled Testimony, Exhibit 22

Notes: $PM_{2.5}$ emissions are conservatively assumed to be equal to PM_{10} emissions.
The $PM_{2.5}$ Canada-wide standard is based on the 98th percentile averaged over three years, therefore the modeled and background values indicated above are also based on these assumptions.
NO_X is considered to be fully converted to NO_2.
Excludes the effect of refinery emissions reductions.

Dust

Onsite roads and parking areas would be constructed with asphalt over a compacted subbase. These roads would be paved to minimize the potential for fugitive dust emissions from vehicle traffic. Significant quantities of dust would not be generated during operation of the proposed facility.

Odors

Operation of the proposed facility is not anticipated to create nuisance odors. Natural gas may be odorized, but it would be contained within the natural gas pipeline and cogeneration facility piping system up to the point of use in the combustion gas turbines and HRSGs where it would be combusted.

Anhydrous ammonia would be used in the SCR system as a reaction agent for the control of NO_x emissions. Unreacted ammonia would be present in the HRSG exhaust gas flow. Ammonia is commonly perceived as having an odor (e.g., household cleaners). However, based on the quantity to be released through the HRSG stack, ammonia odor is not expected to be detectable. In fact, the dispersion modeling conducted for ammonia at a rate of 5 ppm (a maximum of 13.2 lbs/hour per turbine and about 173 tons/year total) from the HRSG stacks indicates that the public exposure to ammonia (approximately 2.8 g/m^3 or 0.004 ppm) would be well below the range of detection (5 to 53 ppm) (Clayton and Clayton 1993). Ammonia emissions would be limited to a 24-hour average of no more than 5 ppm at 15% O_2. Relative to the public health exposure of ammonia, the maximum projected ground-level impact of the ammonia emissions, based on the 5 ppm level, is about 3% of the 100 μg/m^3 24-hour health-based standard identified in WAC 173-460.

Cooling Tower Steam Plume Fogging and Icing

In cold weather, a cooling tower plume would typically persist until the air exiting the cooling tower sufficiently mixes with the surrounding cooler, drier air. If the plume returns to ground level prior to dissipating, it can cause localized fogging or icing of downwind structures and roadways.

Downwind impacts caused by water vapor and water droplets from the cooling towers were modeled by the Applicant using the Seasonal/Annual Cooling Tower Impact Program (SACTIP) computer model. SACTIP calculates the occurrence of elevated visible water plumes and salt deposition, and ground-level fogging and icing. The model simulates downwind dispersion of the steam plumes based on wind data from the local meteorological station and relative humidity data.

The objective of this study was to determine if the cooling tower would contribute to fogging and/or icing on Grandview Road on the north side of the project boundary. The analysis shows that fogging may occur for a total of 2.5 hours a year in the northeast or northwest directions. The area affected by fogging extends from 655 to 1640 feet from the center of the cooling tower.

Grandview Road is approximately 1,312-feet in these directions and, therefore, may be affected by the edge of the plume for these few hours of the year.

In order for roadway icing to occur, the cooling tower plume needs to touch down on the road surface, the plume must become condensed, and the temperature of the road surface must be below freezing. Cooling tower modeling shows that roadway icing would not occur (Torpey, pers. comm., 2004).

3.2.4 Impacts of No Action

Under this alternative, existing natural-gas-fired power plants would be more likely to continue operations. No new hydroelectric generating capacity is being planned, and the development of nuclear power plants has been halted. Wind and solar power do not have the generating availability needed to meet continuous electricity demand, but they could allow more flexibility in managing baseload resources. Fuel cell technologies are being developed, but remain relatively small and expensive. Natural-gas-fired combined-cycle combustion turbine plants would meet the increasing demand for baseload electricity generation. If the proposed cogeneration facility were not built and operated, the refinery and others in the region would use electricity produced by existing sources of generation, electricity produced by other new sources of generation, or through regional user-side electricity efficiency savings.

If other natural-gas-fired plants are built to meet regional electric demand, it is less likely that they would be planned as cogeneration facilities and therefore would produce energy less efficiently than the project. This would likely result in higher criteria pollutant and greenhouse gas emissions per kilowatt-hour. Also, emission reductions associated with removal of BP refinery boilers would not be realized.

3.2.5 Greenhouse Gas

Overview

The issue of how emissions from human activities might affect global climate has been the subject of extensive international research over the past several decades. There is now a broad consensus among atmospheric scientists that emissions caused by humans are resulting in a rise in global temperatures, although there is still uncertainty about the magnitude of future impacts and the best approach to mitigate the impacts. Two sets of key research documents have recently been published.

The United Nations Intergovernmental Panel on Climate Change (IPCC) published its most recent set of five-year progress reports summarizing worldwide research on global warming (IPCC 2001). These reports indicated that some level of global warming related to human activity is likely to occur and that there is a significant possibility of severe environmental impacts. Several alternative measures were evaluated to achieve the emission reductions specified by the Kyoto Protocol.

President Bush requested the National Academy of Sciences to provide a brief comprehensive review of the IPCC reports (National Academy of Sciences 2001). The review panel included atmospheric scientists with a range of opinions on future global warming. The National Academy of Sciences review was written in lay terms and focused on addressing several fundamental issues. The panel concurred with most of the findings by the IPCC.

Regulatory Framework

Currently, there are no international, national, Washington State, or local regulations that set numerical limits on greenhouse gas emissions, however the Kyoto Protocol has been established and is discussed below. Within the State of Washington, rules relating to siting energy facilities (WAC 463-42-225, Proposal-emission control) requires an Applicant to demonstrate that highest and best practicable treatment for control of emissions is used for a number of air pollutants, including CO_2. The Washington regulation does not specify how "highest and best practicable treatment" for CO_2 is to be quantified. On March 31, 2004, the governor signed Substitute House Bill (SHB) 3141 into law. (The law relates to mitigating carbon dioxide emissions from fossil-fueled electrical generation.) SHB 3141, however, does not apply to the BP Cherry Point Cogeneration Facility Project because the BP West Coast Application was filed prior to the enactment date (June 10, 2004).

Several jurisdictions in the Pacific Northwest have committed to, or require, the mitigation of greenhouse gas emissions, for example:

- The State of Oregon's target is a 17% reduction compared to the most efficient power plant operating in the United States.
- Seattle City Light's greenhouse gas program cites a target of 100% elimination of net future increases of greenhouse gas emissions from all new fossil fuel generating stations added to the city's generating mix (Seattle City Light 2001).
- BC Hydro plans to contract with third-party organizations to procure offsite greenhouse gas projects to offset 50% of the increase in greenhouse gas emissions from two new natural-gas fired electrical generating stations on Vancouver Island, up through the year 2010 (BC Hydro 2003). The year 2010 was specified in the Kyoto Protocol as the date upon which signatory nations must reduce their greenhouse gas emissions. Presumably, new emission reduction programs enacted in response to the Kyoto Protocol (or similar rules) would take effect after BC Hydro's voluntary offset program expired in 2010.

In Washington State, four approved thermal power projects under EFSEC jurisdiction are also required to mitigate greenhouse gas emissions. The requirements, established on a case-by-case basis by EFSEC, are as follows:

- The Chehalis Power Project must acquire greenhouse gas offsets for up to 8% of the overall emissions; Chehalis Power would acquire offsets on a ton-for-ton basis from a recognized supplier, such as the Climate Trust, or by participating directly in greenhouse gas mitigation projects;
- The Sumas Energy 2 Generation Facility is required to mitigate CO_2 emissions according to the monetary path of the Oregon Energy Facility Siting Council, at \$0.57 per ton of carbon

dioxide, based on a 30-year operating life, with no surcharge for administrative expenses; the approximate $8.04 million payment would be made in five annual installments starting at the time the facility begins to operate.

- The Satsop Combustion Turbine Project is required to mitigate CO_2 emissions from the facility that exceed 0.675 lb/kWh, at a rate of $0.57 per ton of CO_2 to be mitigated based upon the facility's maximum potential emissions, and adjusted annually according to the Producer Price Index; 7.5% administrative costs would be paid in addition to the per ton mitigation fee; payments would be made annually for the first 30 years in which the facility operates.
- The Wallula Power Project is required to implement a "Greenhouse Gas, Environmental Mitigation Enhancement Package" which includes payment of approximately $6.0 million to non profit and tribal organizations committed to the development of renewable energy resources and projects, and/or preservation and restoration of fish and wildlife habitat and other environmental programs benefiting the Walla Walla region.

No other operating or permitted facilities in Washington State are subject to greenhouse gas mitigation requirements.

Project Greenhouse Gas Emissions

The significant portion of greenhouse gas emissions generated by the proposed project would result from the combustion of natural gas, a fossil fuel in the cogeneration facility. For purposes of evaluating greenhouse gas emissions, the combustion efficiency of the proposal is quantified by the CO_2 emission factor, with units of pounds of CO_2 emitted per kilowatt-hour of electricity produced. Table 3.2-28 lists the CO_2 emission factors for typical fossil-fueled generating stations operating today. As shown in the table, combined cycle combustion turbines emit much less CO_2 than other types of fossil-fuel power plants. The estimated overall CO_2 emission factor for the proposed cogeneration facility is 0.83 pound per kilowatt-hour (lbs per kWhr).

Table 3.2-28: Typical CO_2 Emission Factors for Electrical Generating Stations

Generating Station Fuel Type	CO_2 Emission Factor (lbs CO_2 per kWhr)
BP Cogeneration Facility, natural gas-fired combined-cycle combustion turbine	0.83
Natural gas fuel combined-cycle combustion turbine	0.87
Natural gas fuel, conventional gas-fired boiler	1.32
Fuel oil, conventional oil-fired boiler	1.97
Coal, conventional coal-fired boiler	2.10
Other solid fuel generating stations	1.38
Nationwide average for electric utility generating stations (1998)	1.34

Sources: BP 2002; U.S. Department of Energy 2000; EFSEC 2002.

Assuming an 85% capacity factor for the plant, the estimated annual CO_2 emissions from the cogeneration facility would be 2.2 million tons per year. Fugitive leaks of natural gas from pipeline systems serving natural gas generation facilities have been estimated to emit methane equivalent to 12% of a project's stack emissions of greenhouse gas (U.S. Department of Energy 2000). Based on this emissions factor, the estimated greenhouse gas emissions generated by leaks from various supply pipelines serving the BP cogeneration project could be up to 13,000 tons of methane per year.

Mitigation Measures

The Counsel for the Environment and the Applicant have agreed to certain obligations, commitments, and restrictions to be incorporated into the Site Certification Agreement as conditions for the project should EFSEC recommend, and the governor approve, that the project be certified. Those obligations, commitments, and restriction related to the control of greenhouse gas (GHG) are summarized below:

1. BP Ownership and BP Corporate Policy. If the Applicant holds an equity (ownership) interest in the project, the Applicant shall voluntarily offset its ownership (equity) share in the project's emissions through GHG emission reductions within BP's worldwide operations, consistent with its voluntary corporate policy. The Applicant shall provide EFSEC with a copy of the independent audit of BP's greenhouse gas emissions prepared on an annual basis under that policy. However, in the event that BP changes, discards, or significantly alters its current corporate GHG objective such that the result is a lesser commitment to GHG emission reduction than provided in subsection 2 below, BP shall be required to mitigate project GHG emissions according to subsection 2 below.
2. Mitigation Requirement. If the Applicant sells the project to a third party, or BP changes, discards, or significantly alters its current corporate GHG objective as described above, the following GHG mitigation requirements shall apply.
    a. The Certificate Holder or third party shall mitigate 23% of the project's actual CO_2 emissions on an annual basis. Mitigation may be accomplished by any combination of:
        i. Boiler Offsets - CO_2 emissions avoided by providing steam to the BP Cherry Point Refinery.
        ii. Other Offset Projects – The implementation of offset projects approved in advance by EFSEC.
        iii. Funding to an Approved Organization - Providing funding to an approved organization that implements GHG reduction projects, such as the Climate Trust. The amount to mitigate each metric ton of CO_2 will be $0.87 for the first year of the project's operation and will increase in subsequent years according to the Producer Price Index (PPI) for All Commodities (WPU-00000000) as reported by the Bureau of Labor Statistics.
    b. Timing and Verifying Actual Emissions and Boiler Offsets.
        i. Sixty days prior to the start of the project's commercial operation, the third party shall pre-pay mitigation based upon the project's maximum potential CO_2 emissions for the first year of operation minus the CO_2 emissions expected to be avoided by providing steam to the BP Cherry Point Refinery, either by provide funding to an approved organization and notifying EFSEC, or by providing EFSEC with documentation demonstrating the implementation of an approved offset project.

ii. One year and 30 days following the start of the project's commercial operation, the Applicant shall file with EFSEC a report documenting the project's actual CO_2 emissions for the first year of operations and the actual amount of CO_2 emissions avoided by providing steam to the BP Cherry Point Refinery during that year. The report will also present a reconciliation of the mitigation obligation for the first year and the mitigation provided. If the third party has provided more mitigation than is due, the third party would receive a credit against its obligation for the following year. If the third party has provided less mitigation than is due, it would provide the additional mitigation owed. The third party shall also pre-pay mitigation for the next year's maximum potential CO_2 emissions in the manner described in subsection (i) above at that time. This process shall continue on an annual basis for the 30-year assumed life of the project, except that the cost per ton will be adjusted by the PPI ratio as indicated in subsection 2.a.iii above.

iii. An example is provided in Exhibit 10.1 admitted in the EFSEC hearing record.

c. Approved Organizations. If the third party elects to satisfy its mitigation obligation by provided funding to an approved organization as described above, it shall provide funding to an organization qualified to administer such funds and that has been approved by EFSEC. In selecting mitigation projects, the approved organization shall give preference and priority to offset projects located within Whatcom County or the immediate surrounding counties where the project is located, and second within the state of Washington. The organization shall file biennial reports with EFSEC on actual offsets achieved and a statement of costs for the period. The organization may seek approval from EFSEC to bank money received from BP for a period of up to three years so that larger mitigation projects may be pursued. In no instance shall the organization use more than 10% of the total funds received for selection, monitoring, evaluation, management, and enforcement of contracts.

3. If the Applicant sells a portion of the project to a third party, assuming the Applicant's voluntary policy is still in effect, the Applicant shall voluntarily offset its ownership (equity) share of the project's CO_2 emissions as provided in subsection 1 above, and the third-party Certificate Holder shall mitigate its ownership (equity) share of the CO_2 emissions as provided in subsection 2 above.

3.2.6 Secondary and Cumulative Impacts

Cumulative Impact of the ISOM Project

ISOM Toxic Pollutant Emissions

The ISOM project would emit small quantities of TAPs regulated by Ecology. Sources of TAPs include combustion of refinery fuel gas in the ISOM Process Heater, Replacement Boiler No. 2, and increased use of the Hydrogen Heater; fugitive releases from ISOM Unit components; and storage tank vents. No toxic air pollutants generated by the ISOM project are emitted in quantities that exceed their respective ASIL (NWAPA NOC Worksheet, NOC No. 814). Table 3.2-29 lists the criteria pollutant emissions from the BP ISOM project.

Table 3.2-29: BP ISOM Project Emissions

Criteria Pollutant	Emissions in tpy
NO_x	65
CO	113.0
VOC	34
PM/PM_{10}	18.5
SO_2	63
H_2SO_4	1.3

Source: BP 2003

Cumulative Impact of Refinery and Cogeneration Facility Reductions

In combination with the removal of refinery utility boilers, the proposed cogeneration facility would result in an overall reduction in ambient concentrations of PM_{10}. These values represent the modeled impact of primary PM_{10} emissions. Removal of the refinery boilers resulting from steam purchase from the cogeneration facility would significantly reduce NO_x emissions from the refinery, and would consequently also reduce secondary particulate in the airshed. The reduction in secondary particulate is expected to be greater than the increase in primary particulate emissions.

Bonneville Regional Air Quality Modeling Studies

In response to the regional boom in energy facility proposals which occurred in 2001-2002, and in order to address the cumulative impacts of the large number of potential applicants requesting interconnection with the federal transmission system, Bonneville initiated a Regional Air Impact Analysis to evaluate the potential impact of these facilities on airsheds in the Pacific Northwest. (Bonneville 2001a, 2001b, 2001c).

This study examines the potential contribution of the proposed BP Cherry Point Cogeneration Project to regional haze in Class I areas within the Bonneville Service Area, the Columbia River Gorge National Scenic Area (CRGNSA), and the Mt. Baker Wilderness. Regional haze impacts are assessed following the techniques used in the Phase I study conducted by Bonneville. Bonneville's Phase I study examined potential air quality impacts associated with over 40 recently proposed power generating projects in the area. Based on the results of the Regional Air Quality Modeling Study, Bonneville is now examining potential cumulative regional haze impacts on a case-by-case basis for each new project before issuing a Record of Decision (ROD) for each project. Since it is unlikely all the proposed power generating projects would be built, the analysis investigates the cumulative impacts from a Baseline Source Group consisting of projects that have already been issued a ROD, other recently permitted power projects not requesting access to Bonneville's transmission grid but within the area, facilities well along in their permitting process, and the facility being considered for a ROD. The remainder of this section describes the Baseline Source Group, provides an overview of the dispersion modeling approach, presents the results of a cumulative analysis for the Baseline Source Group, and discusses the potential contribution of the BP Cherry Point Cogeneration Project to regional haze.

Phase I examined three scenarios regarding the number of future power generating projects to be operated in the region:

- A worst-case scenario in which a total of 45 new power projects were built and operated simultaneously at their rated capacity using their primary fuel for a total of more than 24,000 MW;
- A second scenario with 28 new power projects, totaling a little over 11,000 MW operated simultaneously by 2004; and
- A third scenario with 15 new power projects totaling 7,000 MW by 2004, which is the most likely scenario in the next 10 years based on projection of need for new energy.

Phase II attempted to model the individual contribution of each new project to the overall cumulative impact. The Phase II analysis for the proposed cogeneration facility is essentially the same as the 7,000 MW scenario from Phase I.

Modeling Overview of Phase I

The dispersion modeling techniques used in the study are as follows:

- The study looked at two scenarios: (1) air impacts that would accrue if 28 of the projects were built and energized by 2004, and (2) air impacts that would occur if all 45 projects were built as planned and operated simultaneously.
- NO_x, PM_{10}, and SO_2 emissions from 45 proposed power projects with a combined capacity of more than 24,000 MW were considered in the analysis.
- The study evaluated impacts on 16 Class I/Scenic/Wilderness Areas (three National Parks, the Spokane Indian Reservation, and 12 wilderness areas), CRGNSA, and the Mt. Baker Wilderness Area.
- PM_{10} concentrations include both primary and secondary aerosols, and the nitrogen deposition estimates include the ammonium ion.

<u>Areas Showing Greatest Impact</u>

Results showed that the greatest air quality impacts would occur in the Puget Sound lowlands from Centralia to Bellingham, in the Hermiston area, and in the eastern portions of the Lower Columbia River Basin.

<u>Class II Significant Impact Levels Not Exceeded</u>

With the exception of two receptors, predicted concentrations from the proposed power plants are less than the SILs for all pollutants and averaging periods. The peak PM_{10} concentration occurred near the Wallula Gap. The predicted PM_{10} concentration at this location was 4.54 $\mu g/m^3$ because all of the projects are scheduled to be energized prior to 2004. The peak PM_{10}

concentration of all the proposed projects at this location was 12.4 µg/m^3. The SILs were also exceeded in one other location; the 24-hour PM_{10} SIL was exceeded at a receptor near the Tacoma tide flats, where the model predicts a 24-hour PM_{10} concentration of 6.2 µg/m^3. The SILs are thresholds used in the evaluation of individual, not multiple, facility impacts on the NAAQS. These receptors are not near the proposed project and not affected by project emissions.

National Ambient Air Quality Standards

This study has not examined local impacts from the power projects, but model results suggest that even if all the proposed power projects were energized, they are unlikely to exceed the NAAQS.

Proposed Class I Significant Impact Levels Exceeded at Several Locations

If all the projects scheduled to be energized before 2004 are built, their emissions are predicted to exceed the proposed 24-hour PM_{10} Class I SIL (0.3 µg/m^3) in the CRGNSA and in the Spokane Indian Reservation. When all 45 proposed sources were included in the model, the proposed 24-hour PM_{10} Class I SIL was exceeded in 11 out of 18 Class I/Scenic/Wilderness Areas. However, Bonneville anticipates only a small portion of these plants will likely be built. These receptors are not near the proposed project site and are not affected by project emissions.

Increment Consumed

Predicted concentrations of PM_{10}, NO_x, and SO_2 from the proposed power projects are small fractions of the applicable Class I increments. For example, the peak PM_{10} concentration was only 1.54 µg/ m^3 in the CRGNSA, which is well below the 24-hour PM_{10} Class I increment of 8 µg/ m^3.

Nitrogen and Sulfur Deposition

Annual nitrogen and sulfur deposition predicted for the Class I/Scenic/Wilderness Areas, the CRGNSA, and the Mr. Baker Wilderness are less than 1% of the background deposition rates provided by the federal land managers for these areas.

Affected Visibility

The study results suggest the proposed power projects could degrade visibility in Class I areas, as characterized by guidance criteria establish by the federal land managers. The model predictions indicate emissions from the projects scheduled to be energized prior to 2004 would degrade visibility on very clear days by more than 5% at 14 out of 18 Class I/Scenic/Wilderness Areas and by more than 10% at 8 areas. If all 45 of the proposed projects are built, visibility on very clear days has the potential to be frequently degraded by more than 10% at 12 out of 18 Class I/Scenic/Wilderness Areas and in the surrounding Class II areas. The sensitive areas most affected by the first group of projects (energized before 2004) are Mt. Rainier, the Alpine Lakes Wilderness, and the Mt. Baker Wilderness Areas. The inclusion of all proposed projects (preand post-January 2004) results in more than 10% change in visibility in 12 out of 18 of the Northwest's Class I/Scenic/Wilderness Areas.

Overview of Phase II

Peak emissions from the 15 projects within the Phase II Baseline Source Group, including the BP Cherry Point Cogeneration Project, are listed in Table 3.2-30. Emissions are shown both for primary and secondary fuels.

Table 3.2-30: Baseline Source Group Plus the BP Cherry Point Project Peak Emissions with Primary Fuel

No.	Project Name	Owner	MW	Peak Emissions (lb/hr)		
				SO_2	NO_x	PM_{10}
1	Fredonia Facility	PSE	108	3.5	23.2	6.8
2	Rathdrum Power, LLC	Cogentrix	270	2.7	29.8	21.4
3	Frederickson Power	West Coast	249	10.2	19.7	16.9
4	Coyote Springs 2	Avista	280	1.1	30.0	4.5
5	Goldendale Energy Project	Calpine	248	12.7	14.9	11.8
6	Hermiston Power Project	Calpine	546	2.5	71.7	38.1
7	Chehalis Generating Facility	Tractebel	520	20.8	40.9	31.6
8	Goldendale (The Cliffs)	GNA Energy	300	3.7	20.3	16.3
9	Big Hanaford Project	TransAlta	267	6.5	23.1	14.3
10	Mint Farm Generation	Mirant	319	4.0	25.1	23.1
11	Satsop CT Project - Phase I	Duke	650	6.7	43.4	47.0
12	Wanapa Energy Center	Confed.Tribes	1200	13.9	98.8	124.8
13	Plymouth Generation	NESCO	307	17.3	18.4	24.0
14	BP Cherry Point	BP NW Products	720	15.9	66.9	70.5
15	Summit/Westward (Clatskanie)	Summit	520	8.2	54.0	50.7
Total			6504	130	580	502
Peak Emissions with Secondary Fuel						
1	Fredonia Facility (Oil-Fired)	PSE	104	51.2	23.2	12.2
7	Chehalis (Oil-Fired)	Tractebel	520	238.0	211.5	40.0

Note: The Fredonia Facility has requested fuel oil firing for all hours of the year as a secondary fuel. The Chehalis Generating Facility has requested fuel oil firing for 720 hours per year.

<u>Operating Scenarios</u>

The analysis assumes all projects in Table 3.2-30 are operating at peak load with their primary fuel for the entire simulation period. An oil-firing scenario was also considered, where sources permitted to fire with fuel oil were assumed to operate in this manner over the winter season. It is important to note that peak load operating assumptions likely overestimate impacts, and with the exception of the Fredonia Facility, the projects are not allowed to fire with fuel oil for an entire winter season. In practice, virtually all proponents state that they intend to burn gas except in times of significant shortage.

The oil-burning scenario is a compromise solution to a potentially complex assessment. The present analysis likely overstates potential impacts attributable to the Chehalis Generating Facility because it cannot burn oil every day of the winter. The meteorology on winter days producing the highest impacts may also not occur concurrently with the economic conditions likely to cause these power plants to burn oil. On the other hand, the impacts attributable to the Fredonia Facility (if they are allowed to burn oil every day) may be under-predicted because the analysis limits its oil-fired emissions to winter months.

Modeling Methods

- The CALPUFF dispersion model was applied to both of the simulations. CALPUFF is the EPA's preferred model for long-range transport assessments. CALPUFF treats plumes as a series of puffs that move and disperse according to local conditions that vary in time and space. CALPUFF estimates processes for wet and dry deposition, aerosol chemistry, and regional haze. The contribution of the BP Cherry Point Project to background extinction was assessed using the post-processing utilities included with the CALPUFF model system.
- Wind fields are based on the University of Washington's simulations of Pacific Northwest weather.
- The aerosol concentrations used to characterize background extinction coefficients in the study represent excellent visual conditions. Background visibility parameters are presented in Table 4 of the *Modeling Protocol*.
- The 432-mile by 418-mile study area includes Washington and portions of Oregon, Idaho, and British Columbia. Meteorological, terrain, and land use data were provided to the model using a horizontal grid mesh size of 7.5-mile. The terrain data are based on an average for each grid cell, thus the simulations do not fully resolve potential local impacts in complex terrain. A six-kilometer mesh size sampling grid was used with receptor locations within 16 Class I areas (3 National Parks, the Spokane Indian Reservation, and 12 wilderness areas), the CRGNSA, and the Mt. Baker Wilderness.
- Building downwash effects are not considered in the analysis, and emissions were characterized using a single stack for each facility.

Phase II Results

The CALPUFF modeling system was applied to simulate emissions from the Baseline Source Group using a year of Pacific Northwest weather. The 24-hour average extinction coefficient was used as a measure of regional haze. The analysis predicted the number of days for each season with greater than 5% and 10% change to background extinction (measure of light), respectively. For both the annual natural gas and the winter oil-fired scenarios, the Baseline Source Group could result in a "just perceptible" change to the extinction coefficient on a few days for several of the areas examined in the study. The areas most affected are the Class I areas near the CRGNSA, Olympic National Park, Mt. Rainier National Park, and the Alpine Lakes Wilderness. In Mt. Rainier National Park, the predicted change to background extinction for the winter oil-fired case exceeds the 10% significance criterion on six days. The Baseline Source Group does not exceed the 10% significance criterion on any days when these sources are fired by natural gas.

Potential changes to background extinction due to emissions from the BP Cherry Point Project to Class I areas, the CRGNSA, and the Mt. Baker Wilderness were evaluated. The modeling suggests the proposed facility could increase daily background extinction by up to 8.05%, 2.23%, and 3.21% in the Mt. Baker Wilderness, the North Cascades National Park, and Olympic National Park, respectively. The project would contribute greater than 0.4% on only one day in any one area when the combined group's contribution is greater than 5% and on no days when the group's contribution is greater than 10%. The project would not significantly contribute to regional haze at any of the Class I areas within the Bonneville Service Area, the CRGNSA, or the Mt. Baker Wilderness when the facilities considered in this analysis are fired by natural gas.

The proposed project's contribution to predicted changes in extinction for the winter oil-fired scenario was also evaluated. This figure was constructed from the highest 24-hour extinction coefficient at each receptor predicted for the project during a winter simulation. The proposed project's contributions are not significant on any of the six days when the Baseline Source Group's combined change in extinction is greater than 10% in Mt. Rainier National Park.

Cumulative Impact of Greenhouse Gas Emissions

Global warming is a worldwide problem caused by the combined greenhouse gas emissions throughout the planet. CO_2 emitted from an industrial facility and other sources persists in the atmosphere for over 100 years before it is eventually metabolized by plants or absorbed into the oceans (ICPP 2001). During that 100-year lifetime, a parcel of emissions generated anywhere on the planet will disperse throughout the world and affect climate change everywhere. Thus, climate change in Washington would be affected as much by emissions from power plants in China, for example, as by emissions from the proposed project. To provide perspective on the potential direct impacts of emissions from the proposed project, it is necessary to consider worldwide emissions. Table 3.2-31 lists greenhouse gas emissions worldwide, from the U.S., and from the State of Washington. The table also lists the total estimated future greenhouse gas emissions from the new gas-fired power plants forecast to be built in the Pacific Northwest (Bonneville 2001a).

Potential impacts that could be felt in the Pacific Northwest (Mazza, n.d.) due to greenhouse gases emitted from all sources in the region include:

- Winters with substantially more rainfall, and summers with a larger number of extremely hot days.
- More frequent and destructive flooding and mudslides.
- A disrupted annual water cycle in which snowpack, on which the Columbia and other Northwest rivers depend during summer, could shrink.
- Droughts coming twice as frequently by 2020 and three times more often—three years out of every 10—by 2050.
- Salmon runs diminished or lost to an even greater degree than at present.
- Water shortages that would affect hydroelectric power production and irrigated farms.
- Ski seasons and runs shortened as snowline retreats to higher elevations.
- Forest cover in Oregon and Washington sharply reduced, with forests retreating from the eastern slopes of the Cascades.

- More numerous and intense forest fires and pest infestations, bringing major shifts in tree species distribution across the Northwest.
- Human health impacts resulting from increased air pollution, increased heat waves, and growth of disease-carrying insect populations.
- Rising seas that undermine coastal bluffs, cause landslides, drown highways and waterfronts, bring higher storm surges, and cover tidal marshes vital to fish and birds.

Many air pollutants compose “greenhouse gases,” each of which exhibits a different chemical tendency to affect global warming. The two most common greenhouse gases associated with gas-fired power plants are CO_2 emitted from the exhaust stacks and methane emitted as fugitive leaks of natural gas along pipeline systems. Emissions of various greenhouse gas chemicals are commonly standardized as “carbon equivalents.” The emission rates listed in Table 3.2-31 are standardized as million metric tons of carbon equivalents (MMTCE) per year, to account for the different global warming potential of each greenhouse gas. For comparison, 1 million tons of CO_2 equals 0.25 MMTCE, and 1 million tons of methane equals 5.2 MMTCE.

As listed in the table, most of the worldwide greenhouse gas emissions are in the form of CO_2, while a smaller fraction of the emissions are in the form of other gases such as methane or nitrous oxide. The total annual CO_2 emissions associated with the cogeneration facility would be 0.56 MMTCE if the facility operates at 85% capacity. Based on the data listed in Table 3.2-31, this is 2.5% of the greenhouse gas presently emitted from all sources in Washington State and 5.1% of the amount anticipated to be issued from all proposed future power projects in the Northwest, assuming all of these projects were constructed. The greenhouse gas emissions from the cogeneration facility would be approximately 0.03% of the U.S. emissions. The actual effect on global warming caused solely by emissions from the cogeneration facility is unknown. However, a cogeneration facility produces less greenhouse gas emissions per kilowatt hour of electricity produced than a combined-cycle facility with no cogeneration capability. In a regional perspective, the production of greenhouse gases could be reduced if operation of the cogeneration facility displaces the operation of other less efficient facilities that emit more greenhouse gases per kilowatt hour.

Table 3.2-31: Comparison of Worldwide vs. Local Greenhouse Gas Emissions

Item	Annual Greenhouse Gas Emissions (MMTCE per year)		
	CO_2	Compounds other than CO_2	Total
Worldwide emissions (including U.S. in 1998)	5,660	2,430	8,090
United States Emissions (1998)	1,494	340	1,834
Washington State Emissions (1995)	21	4	25
Anticipated future gas-fired power plants in Washington and Oregon (28 plants, 11,000 MW)	11	1.3	12.3
Proposed BP Cherry Point Cogen emissions at 85% capacity	0.55	0.07	0.63

Sources: IPCC 2001; EPA 2000; CTED 1999
MMTCE – million metric tons of carbon equivalent

The BP Cherry Point Refinery would also realize a net reduction of CO_2 emissions from the purchase of steam from the cogeneration facility rather than production onsite in refinery boilers. The Applicant has estimated that approximately 320,000 tons per year of CO_2 emission reduction would occur in this manner.

Cumulative Impacts of the BP Cogeneration Facility and the Sumas Energy 2 Generation Facility

In response to a scoping comment, the cumulative impacts of the cogeneration facility and Sumas Energy 2 Generation Facility were estimated for the Sumas/Abbotsford area, and compared with the respective standards and objectives in Tables 3.2-32 and 3.2-33. These tables provide a conservative estimate of the cumulative air quality impact of both facilities, considering that the estimates provided for the cogeneration facility might not correspond to identical meteorological conditions under which the SE2 emissions were evaluated. Therefore, conservatively, the cumulative emissions from both of these facilities would be below the applicable standards or objectives.

Georgia Strait Crossing Project

The proposed Georgia Strait Crossing Project (GSX project) would be located within the proposed cogeneration project site, and both projects could have the same construction time frame. The GSX project involves construction and operation of a pipeline that would transport natural gas from existing systems at the U.S./Canada border near Sumas, Washington, to an interconnect pipeline proposed by Canada in Boundary Pass in the Strait of Georgia. The gas transmission system would consist of an onshore and offshore pipeline, interconnect facilities, one new natural gas compressor station, and related facilities. Within a stretch of less than a mile, the cogeneration project and the GSX project would share general common project area. This pipeline would involve many construction activities (spreads), some of which include clearing, grading, trenching, and backfilling. Since the proposed GSX project and cogeneration project might coincide, cumulative dust generation (i.e., particulate matter) would be a possible side effect.

Emissions during the construction of both projects would consist of fugitive dust and combustion exhaust from construction equipment and vehicles. However, with proper mitigation measures (see Section 3.2.7) dust and emission production would be minimal.

Table 3.2-32: Cumulative Total Concentrations Compared to Canadian Air Quality Objective

Criteria Pollutant	Averaging Period	Highest and Cumulative Concentrations (µg/m³)				Most Stringent of Canadian Objective (µg/m³)
		Maximum Existing Background Concentration (µg/m³) [1]	Modeled Maximum Impacts of Sumas Energy 2 (µg/m³) [2]	Modeled Maximum Impacts of BP Cogeneration Facility in Abbotsford (µg/m³)	Cumulative Impact (µg/m³)	
SO_2	Annual	3	0.13	0.0014	3.13	25
	24-hour	8	1.22	0.058	9.80	150
	3-hour	21	4	0.353	25.35	375
	1-hour	29	5.13	1.04	35.17	450
PM_{10}	Annual	14	0.38	0.0079	14.39	30
	24-hour	36	3.67	0.16	39.83	50
CO	8-hour	3,480	3.32	0.45	3,484	5,500
	1-hour	6,960	6.5	2.7	6,969	14,300
NO_2	Annual	29	0.26	0.006	29.27	60
	24-hour	73	2.54	0.12	75.66	200
	1-hour	109	10.73	3.2	122.93	400

Source: BP 2002, GVRD 1999, 2000, 2001

1 Maximum concentration from a three year monitoring period (1999, 2000, 2001).

2 Modeled maximum impacts of Sumas Energy 2 are taken from the SE2 Second Revised Application dated June 29, 2001, Table 6.1-16.

Table 3.2-33: Cumulative Total Concentrations Compared to NAAQS or WAAQS

Criteria Pollutant	Averaging Period	Highest and Cumulative Concentrations (µg/m³)				Most Stringent of NAAQS or WAAQS (µg/m³)
		Maximum Existing Background Concentration (µg/m³) [1]	Modeled Maximum Impacts of Sumas Energy 2 (µg/m³) [2]	Modeled Maximum Impacts of BP Cogeneration Facility in Sumas (µg/m³)	Cumulative Impact (µg/m³)	
SO_2	Annual	3	0.13	0.0046	3.13	52
	24-hour	8	1.4	0.13	9.53	262
	3-hour	21	3	0.57	24.6	1,300
	1-hour	29	6.97	1.7	37.7	1,050
PM_{10}	Annual	14	0.39	0.027	14.4	50
	24-hour	36	4.23	0.43	40.7	150
CO	8-hour	3,480	4.57	0.81	3,485	10,000
	1-hour	6,960	8.82	4.4	6,973	40,000
NO_2	Annual	29	0.27	0.021	29.3	100

Source: BP 2002, GVRD 1999, 2000, 2001

1 Maximum concentration from a three year monitoring period (1999, 2000, 2001).

2 Modeled maximum impacts of Sumas Energy 2 are taken from the SE2 Second Revised Application dated June 29, 2001, Table 6.1-16.

3.2.7 Mitigation Measures

Construction

<u>Mitigation Proposed by the Applicant</u>

Any emission of fugitive dust requires implementation of Best Management and Good Construction Practices. Incorporating mitigation measures into the construction specifications for the project would reduce construction impacts. Possible mitigation measures to control PM_{10}, particulate matter deposition, and emissions of CO and NO_x during construction are listed below.

- Spraying exposed soil with water would reduce PM_{10} emissions and particulate matter deposition. Water would be applied at a rate to maintain a moist surface, but not create surface water runoff or erosion conditions.
- Providing wheel washers to remove particulate matter that would otherwise be carried offsite by vehicles would decrease deposition of particulate matter on area roads and subsequent entrainment from those roads.
- Removing mud deposited on paved, public roads would reduce particulate matter in the area.
- Routing and scheduling construction trucks to reduce delays to traffic during peak travel times would reduce secondary air quality impacts caused by a reduction in traffic speeds while waiting for construction trucks.
- Requiring appropriate emission-control devices on all construction equipment powered by gasoline or diesel fuel would reduce CO and NO_x emissions in vehicular exhaust. Using relatively new, well-maintained equipment would reduce CO and NO_x emissions.
- Planting vegetative cover as soon as appropriate after grading would reduce windblown particulate matter in the area.
- Appropriate measures will be implemented to minimize deposition of particulate matter during transport of materials in trucks.

Operation and Maintenance

<u>Regulated Air Emissions</u>

The Applicant would mitigate air emissions from the proposed cogeneration facility by burning only natural gas in the combustion turbines and duct burners and only low-sulfur diesel fuel in the emergency generator and firewater pump. Over and above the CGT vendor's 9.0 ppm dry, low NO_X technology, NO_X emissions from the CGTs and duct burners would be controlled to the BACT level (2.5 ppm annual average at 15% O_2) through the use of SCR. A catalytic oxidation system would be installed for the control of CO emissions from the CGTs and duct burners to an annual level of 2 ppm (at 15% O_2). This catalytic oxidation system would also provide the added benefit of controlling about 30% of the VOC emissions, including toxic air pollutants. Other pollutants would be controlled using good combustion technology and good operating practices and the combustion of low-sulfur natural gas as a fuel (BP 2002).

Emissions during startup and shutdown would be mitigated by applying the following BACT measures:

- Requirement to follow the startup and shutdown procedures that are developed by the equipment manufacturers and documented by the Applicant in an equipment *Start-up, Shutdown, and Malfunction Procedures Manual;*
- Specific timelines for startups for the combustion turbines and associated equipment in case these proper operating temperatures are not obtained within a reasonable time;
- Measurement of all emissions and summation of emissions into annual emissions; and
- Limitation of the quantity of startup- and shutdown-generated emissions through annual emission limits on NO_X and CO.

Furthermore, in a Settlement Agreement with the Counsel for the Environment, the Applicant has agreed to remove the refinery boilers within six months of the project's commercial operation.

Greenhouse Gas

As long as the proposed cogeneration facility is owned by the Applicant, the project's greenhouse gas emissions mitigation would be a part of BP's corporate greenhouse gas objective and the proposed project emissions would be offset by greenhouse gas emission reductions within BP worldwide operations. See Section 3.2.5 for additional information regarding other mitigation measures. BP's worldwide objective is to hold net GHG emissions at the 2002 level of 90.8 tons (181.66 billion pounds) through the year 2012, while absorbing all new growth in BP company operations.

If, at some point in the future, the Applicant sells the proposed cogeneration facility, mitigation would be provided for greenhouse gas emissions in excess of 0.675 pound CO_2/kWh in the form of an annual payment to a qualifying organization such as the Climate Trust of $0.87/ton CO_2, or greenhouse gas reductions would be obtained by the proposed cogeneration facility owner, or a combination of the two. Mitigation would be satisfied annually for 30 years, which is the assumed economic life of the project. Mitigation would be reported to EFSEC annually.

3.2.8 Significant Unavoidable Adverse Impacts

No significant unavoidable adverse impacts on air quality are identified. The proposed cogeneration facility would emit criteria air pollutants and toxic air pollutants; however, the proposed project would enable the BP Cherry Point Refinery to implement emission (PM_{10}) reductions. When such emission reductions are implemented, it is likely there would be minimal changes in ambient air quality levels, either in the U.S. or in Canada. The various analyses conducted for the PSD application and for other sensitive areas of interest indicate that air emissions associated with the proposed cogeneration facility would not violate ambient air quality standards or objectives, or other regulatory air quality values. Those emissions are not likely to cause any adverse impacts to the protection of human health and welfare, to any soils, vegetation, flora, or fauna, or to any other sensitive areas identified by the National Parks

Service, U.S. Fish and Wildlife Service, U.S. Forest Service, or by Canadian air quality regulatory agencies.

3.3 WATER RESOURCES

The following information has been updated in the Final EIS. These updates and clarifications to both the text and figures do not change the conclusions presented in the Draft EIS.

3.3.1 Existing Conditions

- The scale in Figure 3.3-4 has been revised. The new Figure 3.3-4, located at the end of this section, should replace the one in the Draft EIS.

3.3.2 Impacts of the Proposed Action

- After the last paragraph on Page 3.3-14 of the Draft EIS, the following text should be added.

As originally proposed in the ASC, a perimeter ditch was to be constructed around the entire site to intercept surface water coming onto the site from the south and east. Because of concerns about the potential of this ditch draining Wetland C, the Corps has indicated the ditch will not be permitted in that portion of the site.

- Figure 3.3-8 has been revised to show the updated layout or location of detention pond 1 and the cooling tower within the fenceline of the cogeneration facility. Figure 3.3-8, located at the end of this section, should replace the one in the Draft EIS.

- In the second full paragraph on Page 3.3-21 of the Draft EIS, the sixth sentence should be replaced with the following:

To the extent possible, construction of the storm drainage facilities for the laydown areas would occur when the ground is dry enough to work efficiently.

- In the fourth paragraph on Page 3.3-22 of the Draft EIS, the third sentence should be replaced with the following:

To the extent possible, construction of the water reuse facilities would occur when the ground is dry enough to work efficiently.

- The last sentence in the second paragraph on Page 3.3-23 should be deleted and replaced with the following text.

As originally proposed in the ASC, a perimeter ditch was to be constructed around the entire site to intercept surface water coming onto the site from the south and east. Because of concerns about the potential of this ditch draining Wetland C, the Corps has indicated the ditch will not be permitted in that portion of the site.

- On Page 3.3-23 of the Draft EIS, the following sentence should be added at the end the third paragraph.

> The loss of 30.51 acres of wetland would result in the loss of the associated stormwater storage functions.

- Changes to the following text have been added for clarification. The average amount of reuse water available from an operational Alcoa Intalco Works has been changed from 2,770 gpm to 2,780 gpm. Also, the maximum instantaneous use of the cogeneration facility could exceed 2,801 gpm. As a result, the fifth paragraph on Page 3.3-23 of the Draft EIS should be deleted and replaced with the following text.

> Industrial process water would be supplied through a water re-use agreement between the Whatcom County PUD, the Applicant, and Alcoa Intalco Works for once-through cooling water from Alcoa, assuming Alcoa Intalco is in operation. Under this scenario, Alcoa would be able to provide approximately 2,780 gpm and the excess not used by the cogeneration facility could be used by the refinery, resulting in a net reduction of water withdrawal from the Nooksack River. If Alcoa is not in operation, the average 2,244 to 2,316 gpm of process water required by the cogeneration facility would be supplied directly by the PUD. The maximum instantaneous use at the cogeneration facility could exceed 2,801 gpm. In either case under average conditions, there would be no net increase in water withdrawal from the Nooksack River.

3.3.4 Secondary and Cumulative Impacts

- On Page 3.3-25, the first sentence of the fifth paragraph should be deleted and replaced with the following text.

> Other known or proposed projects in the Terrell Creek watershed include the Georgia Strait Crossing (GSX) pipeline, the BP ISOM unit, and the Brown Road Materials Storage Area. The GSX pipeline traverses about 5 miles of the Terrell Creek watershed. While some wetlands would be excavated, they would be reestablished after construction to restore their hydrologic character. The pump station would be on a 5-acre site, but none of that would be wetland. The ISOM unit would be constructed on existing impervious surface at the refinery where stormwater treatment and detention are already provided. The Brown Road Materials Storage Area would eliminate about 11 acres of wetlands that provide surface water storage but would include 34 acres of wetland mitigation to replace that function. Cumulatively, there would be some incremental loss of wetland surface water storage in the watershed, but it would be offset by onsite treatment and detention and offsite mitigation in the basin.

3.3.5 Mitigation Measures

- As a measure to avoid the potential drainage impact on Wetland C, the Corps of Engineers will not permit the Applicant to install a perimeter ditch along the west side of Wetland C. Because this would become a condition of the 404 permit, the following changes have been made. On Page 3.3-27 of the Draft EIS, the heading "Additional Recommended Mitigation Measures" and text under the heading should be deleted. A new heading "Wetland C" should be added in its place with the following new text under it.

> To avoid the potential for draining Wetland C, the Applicant will not construct the perimeter ditch along the west side of the wetland.

3.3.6 Significant Unavoidable Adverse Impacts

- Because of the avoidance measure to reduce the potential drainage impact on Wetland C, the last sentence on Page 3.3-28 of the Draft EIS should be deleted.

Insert Figure 3.3-4

Insert Figure 3.3-8

3.4 WATER QUALITY

The following information has been updated in the Final EIS. Updated information was obtained from Michael Kyte's prefiled testimony (Exhibit 27R.0) as presented to EFSEC.

3.4.2 Impacts of the Proposed Action

- On Page 3.4-12 of the Draft EIS, the following text should replace the first paragraph after the bullet point.

After treatment in the refinery wastewater treatment system, wastewater from the cogeneration facility would be discharged along with the refinery wastewater to the Strait of Georgia. The cogeneration facility would add approximately 190 gpm on average to the refinery's effluent discharge, assuming 15 cycles of concentration in the cooling tower of non-recyclable process wastewater, to the refinery discharge. Table 3.4-5 presents a numerical analysis of the potential impact of the cogeneration facility wastewater on the refinery's wastewater stream. The impact analysis is based on the average discharge from the refinery wastewater treatment study that was conducted in July, August, and September of 2001.

- The following table should replace Table 3.4-5 on Page 3.4-12 of the Draft EIS.

Table 3.4-5: Potential Impact of Proposed Cogeneration Facility on the Existing Refinery Wastewater Discharge to Outfall 001 in the Strait of Georgia

Parameter	Untreated Cogen Process Wastewater[1]	Treatment Efficiency	Cogen Process Wastewater after Treatment	Refinery Process Wastewater after Treatment	% Increase with Cogen Contribution (after treatment by refinery) [2]
Discharge Flow (gpm)	190	0%	190	2,338	8.1%
Biochemical Oxygen Demand (BOD) lbs./day mg/l	132	98%	2.64	275	1%
Chemical Oxygen Demand (COD) lbs./day	323	96%	12.9	2,235	0.6%
Total Suspended Solids (TSS) lbs./day	98	35%	63.7	427	14.9%
Oil and Grease (lbs./day)	3	98%	0.1	115	0.1%
Total Chromium (lbs./day)	0.32 (1.45)	--	--	0	[3]
Temperature (^{o}F)	93.8	--	--	82.7	<1° F
pH	6.5 - 9.5	--	--	8.0 - 8.6 Min.	NA

1 Wastewater that is "discharged" to the refinery's wastewater treatment system.
2 Based upon treatment efficiencies documented in the BP Cherry Point Treatment Efficiency Study and Engineering Report, May 2002.
3 Not estimated – the Treatment Efficiency Study report shows that metal concentrations are reduced through the refinery wastewater treatment system.

- The following text should be added after Table 3.4-5 on Page 3.4-12 of the Draft EIS.

According to Michael Kyte, (Prefiled Testimony, Exhibit 27R.0), there is no evidence to suggest impacts on fish populations or food sources would result from the discharge of the combined refinery and cogeneration treated wastewater to the Strait of Georgia. Even if the temperature of the discharged effluent increased, the water velocity within the mixing zone would rapidly mix and dilute the treated wastewater. As a result, any substance or temperature increase would rapidly be reduced to ambient levels. In such conditions, it is unlikely that herring or salmon adults, juveniles, or larvae would be subject to higher concentrations of any substance or raised temperatures long enough to cause short-term harm. According to plume modeling conducted by Ecology, the refinery's effluent would be diluted within the zone of initial dilution (ZID) at a factor of 28:1. Outside the ZID, the effluent would be diluted at a factor of 157:1 before reaching the edge of the chronic dilution zone, where all substances or parameters must be equal to ambient conditions. Physical modeling studies conducted in 1990 using dye injected into the refinery effluent showed that the actual dilution ratio within the ZID was 144:1 and the dilution at the edge of the chronic dilution zone was 1,709:1. Therefore, based on this information and on the results of no impacts of the ongoing quarterly acute bioassay testing conducted by BP as part of the refinery's NPDES testing and monitoring requirements, no impacts are anticipated from the combined refinery and cogeneration wastewater discharge.

- In the second paragraph on Page 3.4-14 of the Draft EIS, the second to the last sentence should be deleted. A special groundwater study is not needed because stormwater discharged to the detention facility, and ultimately to CMA 2, would be collected only from uncontaminated areas of the cogeneration facility.

3.4.5 Mitigation Measures

- On Page 3.4-17 of the Draft EIS, the second paragraph should be deleted and replaced with the following text.

Water used for hydrostatic testing would require capture and discharge. The Applicant would meet the requirement of the State Waste Discharge Permit and develop and implement a plan to characterize the hydrostatic test wastewater for conventional and priority pollutants. The results would determine if the wastewater could be properly disposed of in the refinery's wastewater treatment system prior to discharge. Hydrostatic test water would only be discharged to the refinery's wastewater treatment system if testing confirmed that it was within acceptable limits for that system. After treatment, the hydrostatic test water would be discharged to the Strait of Georgia through the refinery's Outfall 001. If hydrostatic test water does not meet criteria for discharge to the refinery's wastewater treatment plant, other offsite disposal options would be necessary.

- On Page 3.4-17 of the Draft EIS, the following text should precede the third paragraph under the heading "Stormwater Mitigation Measures."

EFSEC has developed conditions for the proposed project's National Pollutant Discharge Elimination System Permit, which the Applicant will meet. The permit conditions specify construction stormwater effluent limits and monitoring requirements. The effluent limitations are presented in Table 3.4-7. The Applicant would begin monitoring construction stormwater quality with the start of construction activities.

- On Page 3.4-17 of the Draft EIS, the last sentence and list items 1 through 12 (which continue onto the next page) should be deleted.

- On Page 3.4-19 of the Draft EIS, the heading "Additional Recommended Mitigation Measures" and paragraph below it should be deleted. This section has been deleted throughout the Final EIS.

- On Page 3.4-19 of the Draft EIS, the following text should be added before the third paragraph.

EFSEC has developed State Waste Discharge Permit conditions for operation of the cogeneration facility. These conditions include discharge limitations, monitoring requirements, reporting and recordkeeping requirements, an operation and maintenance plan for water quality treatment facilities, SPCC and hazardous waste management plans, and a SWPP plan. The operation effluent limits are presented in Table 3.4-7.

- On Page 3.4-20 of the Draft EIS and continuing onto the next page, the heading "Additional Recommended Mitigation Measures" and paragraphs below it should be deleted. This section has been deleted throughout the Final EIS.

3.5 WETLANDS

Additional and updated information about wetlands is presented below. Most of the new information relates to potential impacts on Wetland C and potential wetland impacts from the Brown Road Materials Storage Area and the Clean Fuels or ISOM project.

3.5.1 Existing Conditions

- Figure 3.5-2 from the Draft EIS has been deleted. On Page 3.5-3 of the Draft EIS, the first sentence of the first paragraph should be deleted and replaced with the following text.

> Wetlands associated with the cogeneration facility are primarily PEM systems (Figure 3.5-1).

- On Page 3.5-4 of the Draft EIS, the first sentence of the fifth paragraph should be deleted and replaced with the following text.

> Wetlands associated with components of the refinery interface (Laydown Areas 1, 2, and 3, Access Road 2, and pipeline corridor) are primarily PEM systems (Figure 3.5-1).

- A new Figure 3.5-2 has been added to the Final EIS. It is located at the end of this section. On Page 3.5-9 of the Draft EIS, the first sentence of the first paragraph should be deleted and replaced with the following text.

> Two mitigation sites have been identified immediately north of the cogeneration facility and refinery interface site (Figure 3.5-2).

- Figure 3.5-3 has been revised. The revised figure, located at the end of this section, should replace the figure in the Draft EIS.

3.5.2 Impacts of the Proposed Action

- In the third paragraph on Page 3.5-12 of the Draft EIS, the following text should be inserted between the seventh and eighth sentences.

> As identified in the original ASC, a perimeter ditch was to be constructed along the western border of Wetland C. The Corps of Engineers has indicated, however, that construction of this ditch through Wetland C will not be permitted.

- On Page 3.5-13 of the Draft EIS, the first sentence of the second full paragraph should be replaced with the following text.

> This 150-foot-wide, 0.8-mile transmission corridor would require the construction of 4 towers.

3.5.4 Secondary and Cumulative Impacts

- The following text provides additional information on other projects currently being built or to be built in the near future. On Page 3.5-15 of the Draft EIS, the fourth paragraph should be deleted and replaced with the following text.

The proposed Georgia Strait Crossing (GSX) pipeline project is anticipated to be constructed concurrently with the proposed project. Along the more than 33-mile pipeline corridor, approximately 62 acres would be affected by construction, but only 7.4 acres would be permanently affected by vegetation management as part of pipeline maintenance. Within the portion of the pipeline corridor in the Terrell Creek watershed (MPs 28 to 33), about 2 acres would be affected by construction and about 1 acre would be permanently affected by vegetation management. Mitigation for these impacts has been accepted by the Corps.

Currently, the BP Cherry Point Refinery is constructing a Clean Fuels or gasoline isomerization (ISOM) project within the boundary of the refinery. This project would not affect wetlands because the project site is a cleared gravel area. Another BP project to be built in the near future is the Brown Road Materials Storage Area. This project would permanently affect 11 acres of wetlands and temporarily disturb 0.17 acre of wetland in the area south of the proposed cogeneration project. These wetland impacts would be mitigated by rehabilitating approximately 34 acres of wetlands, ponds, and surrounding uplands located within the BP Cherry Point property. The proposed mitigation area for this project is north of Grandview Road and immediately west CMA 2, one of two wetland mitigation sites for the proposed project.

Most of the wetlands identified above to be affected in the Terrell Creek watershed are highly disturbed and dominated by non-native, invasive plant species. The mitigation areas would be constructed with native species. While cumulatively there would be a net loss in wetland area, it is anticipated there would be a net gain in wetland function.

At this time, Whatcom County envisions growth and development in the general area. Potential impacts on wetland systems associated with these projects would depend on the quantity and quality of affected wetland systems and approved mitigation. The proposed project would not contribute to potential cumulative impacts on wetland communities because proposed mitigation measures would create and enhance wetlands with high functional values to replace disturbed wetlands with low functional values.

3.5.5 Mitigation Measures

- The last paragraph on Page 3.5-15 and the first paragraph on Page 3.5-16 of the Draft EIS should be deleted and replaced with the following text.

Mitigation measures consistent with those generally required by the Corps and Ecology for Category III wetlands within western Washington would be carried out during construction and operation of the project to protect wetlands that would not be filled. Wetlands adjacent to the project site, such as Wetland I, would be protected using silt fencing and hay bales. The potential drainage impact on Wetland C from the construction of a perimeter ditch along the west side of the wetland would be avoided by not digging a ditch, as required by the Corps.

The portions of Wetlands A, B, C, and D that would not be disturbed would also be protected using silt fencing and hay bales. Approximately 4.66 acres of Wetland F and 0.2 acre of Wetland B3 would be temporarily disturbed and restored after project construction is completed. Under the proposed mitigation plan, in addition to the 0.2 acre of wetland restoration of Wetland B3, 0.3 acre of wetland creation would occur, for a total of 0.5 acre of wetland restoration and creation in this area of the project site (Appendix C).

- Since the Draft EIS was published, the Applicant completed the Final Cogeneration Project Compensatory Mitigation Plan. Also, the Applicant and Whatcom County approved a Settlement Agreement, which among other things identifies specific measures to make the mitigation sites CMA 1 and CMA 2 more “heron-friendly.” On Page 3.5-16 of the Draft EIS, the last sentence of the third paragraph should be deleted and replaced with the following text.

Detailed information associated with proposed mitigation measures is provided in the Final Cogeneration Project Compensatory Mitigation Plan and all of its attachments (see Appendix C of this Final EIS).

Figure 3.5-2

Figure 3.5-3

3.7 UPLAND VEGETATION, WILDLIFE AND HABITAT, FISHERIES, AND THREATENED AND ENDANGERED SPECIES

Updates to Section 3.7 include insertions of additional information provided by commenters on the Draft EIS and factual corrections. Factual corrections relate to the number of new towers needed to connect the proposed project to the Bonneville Custer-Intalco Transmission Line No. 2. These updates to the text of the Draft EIS do not substantially change the description of existing conditions or the potential impacts resulting from construction and operation of the proposed project. The addition of mitigation measures further reduces the significance of potential impacts on natural resources in and around the project area. The following is updated information that has been added to the Final EIS.

3.7.1 Existing Conditions

- On Page 3.7-15 of the Draft EIS, the following sentence should be added to the end of the third paragraph.

The WDFW Priority Habitat and Species database also identifies a bald eagle nesting site within 400 feet of the existing Custer-Intalco Transmission Line No. 2 (see Appendix B, Section 3.1.4, Page 21 of the Draft EIS and Letter 18, Response 2 in Volume 2 of this Final EIS.

- On Page 3.7-17 of the Draft EIS, the following text should be added to the end of the first paragraph.

During prefiled testimony, Michael Kyte stated that the herring stock at Cherry Point has declined. He further testified that he has not seen evidence of adverse effects resulting from the discharge of wastewater from onshore industries (Kyte, Prefiled Testimony, Exhibits 27.0 and 27R.0).

3.7.2 Impacts of the Proposed Action

- On Page 3.7-20 of the Draft EIS, the following text should be added at the end of the fourth paragraph.

Transmission line construction activities could disturb bald eagle nesting from mid-March to mid-June.

- On Page 3.7-22 of the Draft EIS, the following text should be added after the last sentence of the first paragraph.

The Birch Bay great blue heron rookery is located about 1.5 miles from the project site. WDFW management recommendations for great blue heron include a 3,280-foot buffer between heron colonies and construction activities (WDFW 2004).

- On Page 3.7-23 of the Draft EIS, the first sentence of the fourth paragraph should be deleted and replaced with the following text.

Installation of the transmission system requires a 150-foot-wide, 0.8-mile-long corridor consisting of four new towers.

- On Page 3.7-23 of the Draft EIS, the first sentence of the fourth paragraph should be deleted and replaced with the following text.

As described above in the upland vegetation section, the four tower pads would cover approximately 0.29 acre.

- On Page 3.7-25 of the Draft EIS, the following text should be added after the first full sentence at the top of the page.

Bonneville would consult with WDFW during design of the transmission line to develop the Hydraulic Project Approval.

3.7.5 Mitigation Measures

- On Page 3.7-35 of the Draft EIS, the last sentence of the first paragraph should be deleted and replaced with the following text.

To minimize and control the spread of noxious weed species, all equipment would be cleaned before leaving the site during initial clearing activities.

- Since the Draft EIS was published, the Applicant completed the Final Cogeneration Project Compensatory Mitigation Plan. Also, the Applicant and Whatcom County approved a Settlement Agreement, which among other things identifies specific measures to make the mitigation sites CMA 1 and CMA 2 more "heron-friendly." On Page 3.7-35 of the Draft EIS, the last sentence of the second paragraph should be deleted and replaced with the following text.

Detailed information associated with proposed mitigation measures is provided in the Final Cogeneration Project Compensatory Mitigation Plan and all of its attachments (see Appendix C of this Final EIS).

- On Page 3.7-36 of the Draft EIS, the following text should be added after the last sentence of the second paragraph.

Bonneville would avoid transmission line construction and maintenance activities near the known bald eagle nesting site from mid-March to mid-June.

- In the Settlement Agreement between the Applicant and Whatcom County, there is a stipulation for site restoration. On Page 3.7-36 of the Draft EIS, the following text should be added after the third paragraph.

As part of the Settlement Agreement between the Applicant and Whatcom County, the Applicant agrees to prepare an initial site restoration plan and submit it at least 90 days prior to the beginning of site preparation. The Applicant would also prepare and submit a detailed site restoration plan to EFSEC for approval within 12 months of the project's completion. The detailed site restoration plan would identify a reasonable time frame for the work, taking into account the various phases of restoration and the anticipated future use of the site.

3.8 ENERGY AND NATURAL RESOURCES

Additional and updated information about the availability and potential impacts on natural resources has been added to the Final EIS. The Final EIS also notes that the Chehalis Power Station began operation since the publication of the Draft EIS. The revised information about energy and natural resources does not affect the conclusions of the section as presented in the Draft EIS.

3.8.1 Existing Conditions

- On Page 3.8-4 of the Draft EIS, Table 3.8-4 should be deleted and replaced with the following:

Table 3.8-4: Washington Generation Facilities Currently Under Construction

Facility	Developer	Facility Type	Size (MW)	Expected On-Line Date
Chehalis Power Station [1]	Tractebel Power, Inc.	Comb Cycle	520	Qtr. 3/2003
Coyote Springs 2	Avista	Comb Cycle	260	Qtr. 3/2003
Goldendale	Calpine Corp.	Comb Cycle	248	Qtr. 2/2004
Satsop CT Project	Duke Energy	Comb Cycle	650	Construction Suspended

Source: PSE 2003
1 - Station has begun operation since the publication of the Draft EIS.

3.8.1 Existing Conditions

- On Page 3.8-10 of the Draft EIS, the following text and table should be added after the third paragraph.

Overall, the North American natural gas resource base is feeling the effects of its maturity, with production from conventional wells flattening out since the mid 1990s, and non-conventional gas resources making up the balance (National Petroleum Council 2003 and U.S. Department of Energy 2004). The Energy Information Administration (EIA) forecasts that by 2025, 43% of total production in the lower 48 states of the U.S. would be met by unconventional resources. Table 3.8-7 summarizes U.S. natural gas supply projections developed by the California Energy Commission and the EIA.

Table 3.8-7: Projected Natural Gas Supplies for the United States (in trillion cf/yr)

Supply Sources	Projected 2003	Projected 2008	Projected 2013	Projected 2025 AEO2004
Lower 48	18.664	20.277	21.746	21.29
Canada	4.209	4.503	4.853	2.56
Other sources[1]	1.200	1.887	2.688	4.68[2]
Total	24.072	26.668	29.368	31.41

Source: California Energy Commission 2003, U.S. Department of Energy 2004.

1 Other sources include: fuel available from fuel switching, liquefied natural gas (LNG) receipt at existing U.S. import facilities, and Mexican imports; assumes no new LNG facilities, but expansion of existing facilities as LNG imports become a more cost effective resource.

2 Includes LNG and imports from Mexico

In the short term, it is expected that overall declines in U.S. production from the lower 48 states will be made up through development of non-conventional resources and increased production from the Rocky Mountain region as noted above. The National Petroleum Council (NPC) has projected that in the longer term (2025), production from the lower 48 states and non-arctic Canada would only make up 75% of U.S. demand. The EIA and the NPC have concluded that the balance of supply would come from the most cost-effective combination of the following resources:

- Development of Canadian Arctic Gas: The MacKenzie Delta natural gas pipeline is projected to begin moving supplies to U.S. buyers in 2009, with maximum annual throughput of 675 billion cubic feet reached in 2012 and continuing through 2025. However, it is also expected that a significant portion of the gas production of the Mackenzie Delta fields would be consumed within Canada.

- Liquid Natural Gas (LNG) Imports: Supplies of natural gas from oversea sources, imported through U.S. liquefied natural gas terminals, account for most of the projected increase in net imports in both the EIA and NPC forecasts. It is projected that expansion of LNG capacity would occur through both expansion of the four existing facilities in the U.S. (three on Atlantic seaboard, one on the Gulf Coast) and development of new facilities. As of December 1, 2003, there were 32 proposals for new terminals; however, proposals for new capacity involve significant risk and uncertainty both within and outside the U.S. and are not all expected to move forward.

- Development of U.S Arctic Gas: Both the U.S. Department of Energy (2004) and NPC forecasts project the development of North Slope Alaska fields, with operation beginning only after 2015. Although the potential of the Alaska gas resource is known to be large, uncertainty surrounds its development because the resource is stranded from the U.S. market, public opposition, and regulatory factors.

3.8.2 Impacts of the Proposed Action

- On Page 3.8-12 of the Draft EIS, Table 3.8-7 should be changed to Table 3.8-8.

- On Page 3.8-13 of the Draft EIS, Table 3.8-8 should be changed to Table 3.8-9.
- On Page 3.8-14 of the Draft EIS, Table 3.8-9 should be changed to Table 3.8-10.
- On Page 3.8-15 of the Draft EIS, Table 3.8-10 should be changed to Table 3.8-11.
- On Page 3.8-15 of the Draft EIS, the fourth paragraph should be deleted.

3.8.3 Impacts of No Action

- The last paragraph on Page 3.8-16 and the first paragraph on Page 3.8-17 should be deleted and replaced with the following text.

Under the No Action Alternative, the cogeneration facility, refinery interface, 230-kV transmission facility, and other project components would not be constructed and the consumption of energy or natural resources associated with construction and operation of the project would not occur. Existing natural-gas-fired power plants would be more likely to continue operations. No new hydroelectric generating capacity is being added, and the development of nuclear power plants has been halted. Wind and solar power do not have the generating availability needed to meet continuous electrical demand, but they could allow more flexibility in managing baseload resources. Fuel cell technologies are being developed, but these remain relatively small and expensive. Natural-gas-fired, combined-cycle combustion turbine plants would meet the increasing demand for baseload electrical generation. If the proposed cogeneration facility were not constructed, the refinery and industries in the region would use electricity produced by existing sources of generation, electricity produced by other new sources of generation, or through regional user-side electricity efficiency savings.

Under this alternative, the cogeneration facility would not generate and transmit electrical power for use on the Northwest power grid. The No Action Alternative would not remove the need for power production; it would potentially transfer the impacts to another site and another technology. There would be no increase in the power supply reliability for the BP Cherry Point Refinery and no contribution to new electrical generation required to meet increasing power demands in the Pacific Northwest and adjoining regions.

3.8.4 Secondary and Cumulative Impacts

- On Page 3.8-17, the second, third, and fourth paragraphs should be deleted and replaced with the following text and table.

Natural Gas Supply and Consumption

The project would consume 42,457,356 MBtu (approximately 43 MDth) of natural gas annually in the production of electrical energy and steam. The proposed project would incrementally contribute to the regional demand for natural gas and, given existing natural gas transmission system capacity in the region, would represent an additional increment of demand on the system. The cogeneration facility's projected annual natural gas consumption would be relatively small compared to the region's existing and projected future supply, and it would not be expected to significantly affect the overall supply for other users in northwest Washington.

Cumulative impacts on natural gas consumption from the development of this and other gas-fired electrical generation facilities would depend mainly on market forces, regional and national economic growth, and the response of this and other industrial sectors who are large consumers of natural gas and/or electricity. It is anticipated that shifts in the industrial market will accommodate tightening natural gas supplies in a number of ways.

Recent data from the Energy Information Administration (EIA 2004) has indicated a dramatic increase in additions to U.S. electricity generation capacity since 2000, with virtually all of the new capacity using natural gas as fuel. However, natural gas consumption in the electric power sector has not increased as rapidly. From 1995 to 2002, natural-gas-fired generation in the power sector increased by 43%, but natural gas consumption in the power sector increased only 31%. This reduced consumption relative to generation can be attributed to increased efficiency of natural-gas-fired generation. The significant role of natural gas fuel in power generation is expected to continue in the foreseeable future, but the disparity between generating capacity added and natural gas use is also expected to grow for the following reasons.

The modest rate of growth of electricity sales will mean that many of the new facilities are unlikely to operate at full capacity in their early years of operation. Also, as clearly evidenced in the Pacific Northwest in the past 24 months, market forces will dictate the number of new facilities that will actually be constructed and operated (California Energy Commission 2003). Table 3.8-12 summarizes the recent status of natural gas generation (greater than 25 MW) in the Pacific Northwest region (WECC 2004) and clearly indicates a direct decrease in projects being developed due to the weak regional economy and the short term decrease in regional electricity consumption.

Table 3.8-12: Summary of Proposed Combustion Turbine Facilities in the Pacific Northwest

Facility	County	Location	Technology	Output (MW)	Est. Operational Date	Company
Operating Facilities						
Evander Andrews (Mt Home)	Elmore	Idaho	Gas Turbine	90	10/1/2001	Idaho Power Company
Rathdrum	Kootenai	Idaho		270	9/1/2001	Avista/Cogentrix
Exxon I	Yellowstone	Montana	Gas Turbine	20	4/1/2001	Exxon
Albany Cogeneration	Linn	Oregon	Cogen	85	7/1/2000	Willamette
Beaver GT	Columbia	Oregon	Gas Turbine	24	7/1/2001	Portland General Electric
Coyote Springs II	Morrow	Oregon	Combined	280	7/1/2003	Avista/Mirant
Hermiston	Umatilla	Oregon	Combined	530	8/20/2002	Calpine
Hermiston Peaking	Umatilla	Oregon	Combined	100	8/20/2002	Calpine
Klamath Falls Cogeneration	Klamath	Oregon	Combined	500	7/1/2001	PacifiCorp
Klamath Falls Expansion	Klamath	Oregon	Gas Turbine	100	6/1/2002	Pacific Klamath Energy
Morrow Power GT	Morrow	Oregon		25	8/1/2002	Morrow Power
SP Newsprint Cogen	Yamhill	Oregon	Combined	130	7/1/2003	SP Newsprint
Benton PUD (Finley)	Skagit	Washington	Gas Turbine	27	12/20/2001	Benton PUD
Big Hanaford (Centralia)	Lewis	Washington		248	7/1/2002	TransAlta
Boulder Park	Spokane	Washington		25	4/1/2002	Avista
BP Cherry Point GTs	Whatcom	Washington	Gas Turbine	73	9/1/2001	Cherry Point Refinery
Chehalis Generation	Lewis	Washington	Combined	520	10/1/2003	Tractebel
Equilon GTs	Skagit	Washington	Gas Turbine	38	1/1/2002	Equilon Enterprises
Frederickson	Pierce	Washington		249	8/1/2002	EPCOR & Puget Sound Energy
Fredonia Addition	Skagit	Washington	Gas Turbine	106	8/1/2001	Puget Sound Energy
Pasco GTs	Franklin	Washington	Gas Turbine	44	6/30/2002	Franklin/Grays Harbor PUD
Pierce Power	Pierce	Washington	Gas Turbine	154	9/1/2001	TransAlta
SUBTOTAL				3,638		
Facilities Under Construction						
Frederickson Expansion	Pierce	Washington		25	6/1/2005	EPCOR & Puget Sound Energy
SUBTOTAL				25		
Regulatory Approval Received						
Bennett Mountain		Idaho	Peaker[1]	162	7/1/2005	Idaho Power
Silver Bow	Silver Bow	Montana	Combined	500	1/1/2011	Continental Energy Services

1 A facility that operates during peak power demands.

Table 3.8-12: Continued

Facility	County	Location	Technology	Output (MW)	Est. Operational Date	Company
Port Westward	Columbia	Oregon	Combined	650	4/1/2006	Portland General Electric
Summit/Westward	Columbia	Oregon	Combined	520	4/1/2006	Westward Energy LLC
Umatilla Generation Project	Umatilla	Oregon	Combined	610	3/31/2008	PG&E Natl Energy
Frederickson Power 2	Pierce	Washington	Combined	300	1/1/2011	EPCOR & Puget Sound Energy
Sumas 2 Generating Facility	Whatcom	Washington	Combined	660	1/1/2011	National Energy
Wallula	Walla Walla	Washington	Combined	1,350	1/1/2011	Newport Generation
SUBTOTAL				4,752		
Under Review						
Rathdrum GT to CC Conversion	Kootenai	Idaho	Combined	90	9/1/2005	Avista
Basin Creek	Silver Bow	Montana	Reciprocating Engines	48	1/1/2011	Basin Creek Power
COB Energy Facility	Klamath	Oregon	Combined	1,150	6/1/2005	Peoples Energy
Klamath Generating Facility	Klamath	Oregon	Combined	500	1/1/2011	PacifiCorp Power Marketing
Turner	Marion	Oregon	Combined	620	1/1/2011	Calpine
Wanapa Energy Center	Umatilla	Oregon	Combined	1,230	1/1/2011	Eugene Water & Elec
West Cascade Energy Facility	Lane	Oregon		600	12/31/2007	Black Hills Corp
BP Cherry Point	Whatcom	Washington	Combined	720	6/1/2006	Cherry Point Refinery
Plymouth Generating Facility	Benton	Washington	Combined	306	1/1/2011	Plymouth Energy
Tahoma Energy Center	Pierce	Washington	Combined	270	1/1/2011	Calpine
SUBTOTAL				5,534		
Cancelled, Denied Permit, or Delayed Indefinitely						
Garnet Energy Facility I	Canyon	Idaho	Combined	273		Ida-West
Garnet Energy Facility II	Canyon	Idaho	Combined	262		Ida-West
Kootenai	Kootenai	Idaho	Combined	1,300		Newport Generation
Mountain Home (PDA)	Elmore	Idaho	Gas Turbine	104		Power Development Association
Rathdrum II	Kootenai	Idaho	Combined	500		Cogentrix
Montana First Megawatts	Cascade	Montana	Combined	250		Northwestern Corp

Table 3.8-12: Continued

Facility	County	Location	Technology	Output (MW)	Est. Operational Date	Company
Coburg	Lane	Oregon	Combined	605		Coburg Power
Columbia River Energy	Columbia	Oregon	GT	44		Columbia River Energy
Grizzly Power Project	Jefferson	Oregon	Combined	980		Cogentrix
Morrow	Morrow	Oregon	Combined	550		PG&E Natl Energy
Pope & Talbot Cogen (Halsey)	Linn	Oregon	Gas Turbine	93		Oregon Energy
St Helens Cogen	Columbia	Oregon	Combined	141		Oregon Energy
West Linn Paper	Clackamas	Oregon	Combined	94		West Linn Paper
Cowlitz Cogeneration project	Cowlitz	Washington	Combined	395		Weyerhauser
Everett Delta 1 (Preston Point)	Snohomish	Washington		496		FPL Energy
Goldendale	Klickitat	Washington	Combined	248		Calpine
Goldendale NW (The Cliffs)	Klickitat	Washington	Gas Turbine	190		Goldendale NW Alum
Longview Power Station	Cowlitz	Washington	Combined	245		Enron
Mercer Ranch	Benton	Washington	Combined	850		Cogentrix
Mint Farm	Cowlitz	Washington	Combined	286		Mirant
NW Regional Power (Creston)	Lincoln	Washington	Combined	838		Northwest Power Ent
Satsop (Grays Harbor Phase l)	Mason	Washington	Combined	650		Duke Energy NA
Satsop ll (Grays Harbor Phase ll)	Mason	Washington	Combined	600		Duke Energy NA
Sedro-Wooley	Skagit	Washington	Gas Turbine	83		Tollhouse Energy
Starbuck	Columbia	Washington	Combined	1,200		PPL Global
SUBTOTAL				11,277		
Press Release Only						
Black Hills	Hill	Montana		80		Black Hills Power
Blackfeet	Glacier	Montana		160		Adair
Indigenous Global		Washington		1,000		Indigenous Global
Port Frederickson Industrial	Pierce	Washington		324		Morgan Stanley
SUBTOTAL				1,564		
GRAND TOTAL				26,790		

Source: Database of Proposed Generation within the Western Electricity Coordinating Council, February 2, 2004.

New gas-fired electrical generation is significantly more efficient that existing and older gas-fired and oil-fired generation. Whereas older facilities are only 33% or less efficient, newer gas-fired facilities are 45% to 50% efficient. Combined heat and power facilities such as the proposed BP cogeneration project are even more efficient. This efficiency of gas will lead power companies to retire older, less efficient plants, thereby reducing the amount of natural gas consumed per MW of electricity produced.

Finally, the price of natural gas relative to other fuels and the cost effectiveness of new natural gas supplies will determine how much gas will be consumed by the gas-fired electrical generation sector as a whole. The tight balance of supply and demand that is forecast for the next 20 years, associated with the maturing natural gas resource in the U.S. and Canada, will emphasize the cost effectiveness of new gas resources being developed, including liquefied natural gas imports, Arctic gas development in both the U.S. and Canada, and the development of non-conventional gas resources. The cost of the gas produced through these and existing conventional resources will influence the energy sector's natural gas market share in consumption. The generation sector will switch to cheaper fuels as allowed by environmental constraints or make fuller use of gas supply from the new sources (National Petroleum Council 2003 and U.S. Department of Energy 2004).

Electrical Generation

The project would use 146,325 MWh of electrical power annually to generate electricity and steam. However, the overall impacts of electrical energy use would not be significant compared to the total amount of energy being produced by the proposed facility. Operation of the cogeneration facility would cumulatively add to the availability of energy in the Pacific Northwest by generating up to 635 MW of electrical power for distribution on the Northwest power grid.

Other Resources

Approximately 176,850 cubic yards of sand, gravel, fill dirt, and concrete, and 1,050 tons of steel would be used to construct the cogeneration facility, representing an incremental contribution to the regional consumption of these resources. Total permitted gravel resources in Whatcom County are estimated to be approximately 55.2 million tons. The proposed project would use less than 0.05% of these permitted sources in Whatcom County and would not result in a significant cumulative impact on these resources.

3.9 NOISE

Updates to the Draft EIS Section 3.9 include the addition and deletion of text and revision of Tables 3.9-4 and 3.9-5. These updates are based on public comments on the Draft EIS and information provided by the Applicant. The updates to the text and changes to the tables do not change the conclusion about the potential noise impacts presented in the Draft EIS.

3.9.2 Existing Conditions

- On Page 3.9-6 of the Draft EIS, the fourth paragraph should be deleted and replaced with the following text.

Based on the results of the two noise studies, background or ambient noise levels in the project vicinity are higher than expected for a rural environment with residences and scattered industrial facilities. As noted above, wind gusts, creeks, nearby industries, and more importantly, transient noise all contribute to the existing noise environment surrounding the location of the proposed cogeneration facility. These background levels were used in calculating predicted (modeled) noise levels from an operating cogeneration facility. The estimated noise levels combining modeled and background noise levels are shown in Table 3.9-5.

3.9.3 Impacts of the Proposed Action

- The last two paragraphs on Page 3.9-7 and the first three paragraphs on Page 3.9-8 should be deleted and replaced with the following text.

Two studies were performed to predict the noise emissions from the project. The first, conducted by Golder and Associates in 2002, was based on a project designed to use air-cooling. The second, conducted by Hessler Associates Inc., revised the project design to the current configuration using a wet-cooling system. The Hessler noise study predicted operational noise levels at the 15 chosen receptors and estimated noise levels at the selected offsite receptors, based on the anticipated noise levels produced by the proposed cogeneration facility without including the background or transient sounds. The baseline analysis assumed standard power-generating equipment would be used throughout the facility without any special or unusual improvements specifically intended to reduce far-field noise. The primary noise-generating equipment would consist of three CTGs, one STG, three HRSGs, and an air/water cooling tower. Modeling assumed that the CTGs and STG would be housed within standard, acoustically treated enclosures (but not within buildings). Besides the main components, other equipment that could generate potentially significant noise levels, such as boiler feedwater pumps, circulating water pumps, main transformers, and various steam lines, were included in the model.

Standard noise control features such as a combustion turbine inlet silencer, various turbine enclosures, and enclosure of the steam turbine structure below the operating deck were also incorporated into the modeling.

The Hessler study, however, found that a moderate reduction in HRSG stack noise would significantly lower the overall noise levels facility-wide. Consequently, Hessler recommended, and the Applicant accepted, the addition of stack silencers with a nominal reduction of 10 dBA in stack sound; the stack silencers were incorporated into the project design and noise modeling. With this improvement, total noise levels at some of the more critical locations would be reduced by 3 to 4 dBA. The stack silencers also carry an additional benefit that stack noise is less likely to adversely affect levels at receptors situated downwind from the facility. The high elevation of the stacks makes their noise more susceptible to wind effects.

Finally, to ensure the modeling results are conservative, the noise impact modeling predicted the maximum noise levels to be produced by the proposed project. To achieve these conditions, no attenuation factors, such as vegetation or topography, were included in the modeling for existing or future noise results.

Table 3.9-4 presents the projected noise levels of the proposed project at the 15 receptors as originally modeled by Hessler with inclusion of stack silencers. This modeling indicates that the noise levels of the proposed project would be below the regulatory daytime and nighttime allowable levels as shown in Table 3.9-4.

- Table 3.9-4 on Page 3.9-8 of the Draft EIS should be deleted and replaced with the following table.

Table 3.9-4: Estimated Noise Levels without Background Ambient Sound Levels (L_{eq} dBA)

Receptor Location	Hessler's Predicted Noise Level (with stack silencers)	Most Stringent State Regulatory Limit (nighttime)
1 (I)	47	70
2 (R)	41	50
3 (I)	46	70
4 (I)	39	70
5 (I)	40	70
6 (I)	41	70
7 (R)	40	50
8 (R)	34	50
9 (R)	38	50
10 (R)	40	50
11 (R)	40	50
12 (I)	60	70
13 (I)	48	70
14 (R)	44	50
15 (R)	35	50

Note: I=industrial, R=residential

- The last paragraph on Page 3.9-8, which continues onto the next page, should be deleted and replaced with the following text.

As shown above, all of the modeled noise levels produced solely by the cogeneration facility would be below the state regulatory thresholds. Because stack silencers have been added to the project design, Hessler's modeled results were used to calculate the noise levels at the 15 receptor locations to include the background noise conditions combined with the noise produced from the cogeneration facility. Table 3.9-5 outlines the existing background conditions measured by Golder and Hessler, the estimated combined noise levels predicted by Hessler (existing conditions plus the predicted cogeneration noise levels with stack silencers), and the increase above existing noise levels.

- Table 3.9-5 on Page 3.9-9 of the Draft EIS should be deleted and replaced with the following table.

Table 3.9-5: Estimated Noise Levels Combining Modeled and Background Sources (L_{eq} dBA)

Receptor	Daytime Noise Level			Nighttime Noise Level		
	Existing Condition [1]	Existing Condition plus Modeled Level with Stack Silencers [1]	Increase above Existing Condition [1]	Existing Condition	Existing Condition plus Modeled Level with Stack Silencers	Increase above Existing Condition
1 (I)	68	68	0	65	65	0
2 (R)	58	59	1	63	63	0
3 (I)	61	61	0	60	61	1
4 (I)	50	51	1	52	53	1
5 (I)	63	63	0	58	58	0
6 (I)	61	61	0	59	59	0
7 (R)	63/51 (1)	63/51	0	56	56	0
8 (R)	55	55	0	52	52	0
9 (R)	57	57	0	50	50	0
10 (R)	62/42 (1)	62/44	0/2	54	54	0
11 (R)	61/40	61/43	0/3	53	53	0
12 (I)	64	65	1	61	63	2
13 (I)	62	62	0	57	57	0
14 (R)	60/41	60/45	0/4	51	52	1
15 (R)	47	48	1	39	40	1

Note: I=industrial, R=residential
1 Where background measurements were performed by Golder and Hessler, both measurements as shown with Golder data first and Hessler data second.

- On Page 3.9-9 of the Draft EIS, the second and third paragraphs should be deleted and replaced with the following text.

The modeling results presented in Table 3.9-5 indicate that one receptor (14 R) would experience a perceptible increase (above 3 dBA) in noise during the daytime. Two receptors would experience a noise increase over 1 dBA. Receptor 10 is estimated to increase by 2 dBA during the daytime, and Receptor 11 is estimated to increase by 3 dBA during the daytime. Receptor 12 is estimated to increase by 2 dBA at night. As shown on Table 3.9-2, these receptors range from 300 feet to 1.48 miles from the proposed cogeneration facility.

3.9.6 Mitigation Measures

- The first and second bullets on Page 3.9-12 should be deleted.

- Since the Draft EIS was published, the Applicant and Whatcom County have reached a Settlement Agreement regarding conditions of the project, including noise mitigation measures. On Page 3.9-12 of the Draft EIS, the following bullets should be added at the top of the page.

- The Applicant would operate the project in compliance with applicable Washington regulations governing noise from industrial facilities, found in Washington Administration Code Chapter 173-60.
- In addition to applicable Washington regulations, the Applicant would comply with the following limitations when the project is operating normally with all units operating at full load:
  - At Receptor 7 (as identified in Figure 3.9-1 of the Draft EIS), project-only noise would not exceed 47.7 dBA (regardless of wind direction).
  - At Receptor 9 (as identified in Figure 3.9-1 of the Draft EIS), project-only noise would not exceed 45.8 dBA (regardless of wind direction) and would not exceed 70 dBC (regardless of wind direction).
  - At Receptor 10 (as identified in Figure 3.9-1 of the Draft EIS), project-only noise would not exceed 41.5 dBA (during calm wind and winds from all quadrants except southwest) or 45.0 dBA (during wind from the southwest quadrant) and would not exceed 70 dBC (regardless of wind direction).
  - At the Cottonwood Beach receptor, located at 4961 Morgan Road, project-only noise would not exceed 36.4 dBA (during calm winds and winds from all quadrants except southwest) or 43.6 dBC (during wind from the southwest quadrant) and would not exceed 70 dBC (regardless of wind direction).
  - At Receptor 13 (as identified in Figure 3.9-1 of the Draft EIS), project-only noise would not exceed 54.4dBA (regardless of wind direction).
- Within 180 days of the beginning of operation, the Applicant would conduct post-operation noise monitoring at the five receptors identified in the agreement to determine compliance with the noise limitations, and report the results of the monitoring to EFSEC. Compliance would be verified by measurements taken when the project is operating normally with all units operating at full load. Compliance monitoring would be conducted in accordance with the stipulations referenced in the agreement.

3.10 LAND USE

The following information has been updated in the Final EIS.

3.10.1 Existing Conditions

- On Page 3.10-2 of the Draft EIS, the second paragraph should be deleted and replaced with the following text.

Land uses in the project vicinity include a variety of recreational, industrial, commercial, residential, and agricultural uses. Low-density residential uses occur to the north and east of the site and west of the BP Cherry Point Refinery at Point Whitehorn. These residential uses are primarily single-family houses on large lots. Northwest of the refinery, residential properties occur in the bayfront community of Birch Bay. According to U.S. Census data, the Birch Bay Census Designation Place supported 5,105 total housing units in 2000 with a corresponding population of 4,961. Of the total number of housing units, approximately one-half, or 2,620 units, were classified as seasonal or occasional use units (Whatcom County 2003a).

3.13 PUBLIC SERVICES AND UTILITIES

- The gallons per minute (gpm) amount for Alcoa Intalco Works has been corrected. On Page 3.13-16 of the Draft EIS, the third sentence in the second paragraph should be deleted and replaced with the following sentence.

> Under this scenario, Alcoa Intalco Works, when operational, would be able to provide approximately 2,780 gpm, and the excess not used by the cogeneration facility could be used by the refinery, resulting in a net reduction of water withdrawal from the Nooksack River.

3.14 CULTURAL RESOURCES

Changes to this section include clarification of the native plant survey, a factual correction regarding a recommended mitigation measure, and the addition of mitigation measures as recommended by the U.S. Corps of Engineers. The following information has been updated in the Final EIS.

3.14.3 Impacts of the Proposed Action

- On Page 3.14-9 of the Draft EIS, the third paragraph should be deleted and replaced with the following text.

> BOAS, Inc. recorded no cultural resources in this area. The Lummi Indian Nation's second native plant survey has not been completed, however. The results of this study may identify traditional resources in this area. According to the Applicant, the archaeological survey for the Access Road No. 1 area included all but the northern 50 feet of the access road right-of-way (BP 2004).

3.14.6 Mitigation Measures

- On Page 3.14-11 of the Draft EIS, the word "intact" should be deleted from the first sentence in the fourth full paragraph.

- On Page 3.14-11 of the Draft EIS, the last paragraph should be deleted and replaced with the following text.

> The Applicant completed archaeological and native plant surveys at the site of detention pond 2 and its apron, the refinery interface area, and Access Road 3. The Corps reviewed the survey report and made a determination of No Historic Properties Affected. The report and the Corps' determination have been forwarded to the State Historic Preservation Office (SHPO) for review and concurrence. In a letter dated June 14, 2004, SHPO concurred with the Corps' definition of the Area of Potential Effect (APE) and determination of No Historic Properties Affected.
>
> The Applicant will complete additional surveys within the industrial or sanitary wastewater pipelines, Alcoa water pipeline route, and the wetland mitigation areas (CMA 1 and CMA 2) after further design studies but before the start of construction. If no significant archaeological resources are discovered or if the resources would not be affected by the project, mitigation would not be necessary. If significant resources were found and would be affected by the project, the Corps would propose the following measures as conditions to the project 404 permit:
>
> - A professional archaeologist will be onsite to monitor for the presence of archaeological resources during all ground-disturbing construction within the permit area, including CMA 1 and CMA 2.

- A summary report of the findings of the archaeological monitoring or status report will be submitted to the Corps' Seattle District, Regulatory Branch; EFSEC; SHPO; and Lummi Indian Nation within 13 months of permit issuance.
- If human remains or archaeological resources are encountered during construction, all disturbing activities will be immediately stopped in the immediate area and the Applicant shall (within one day of discovery) notify the Corps, EFSEC, SHPO, and Lummi Indian Nation. The Applicant will perform any work required by the Corps in accordance with Section 106 of the National Historic Preservation Act and Corps regulations.
- The remaining or follow-up native plant study will be conducted within the project area and mitigation areas prior to construction and during the growing season. Prior to construction, the study report will be submitted to the Corps and Lummi Indian Nation Cultural Resources Department. After the Corps and the Lummi Cultural Resources Department have reviewed the report, the mitigation plans will be updated to reflect the planting of suitable vegetation within the mitigation and restoration areas.

3.15 TRAFFIC AND TRANSPORTATION

Updates to the Draft EIS Section 3.15 include factual corrections, title clarification for Figure 3.15-7, and additional mitigation measures agreed to by the Applicant and WSDOT since the publication of the Draft EIS. Corrections to text and Figure 3.15-7 and additional mitigation measures are described below.

3.15.1 Existing Conditions

- On Page 3.15-9 of the Draft EIS, footnote 2 in Table 3.15-4 should be deleted and replaced with the following text.

Accidents per million vehicles entering intersection.

3.15.2 Impacts of the Proposed Action

- In the first sentence on Page 3.15-11 of the Draft EIS, the term “Access Road 1” should be deleted and replaced with the following text.

(Access Road 2)

- On Page 3.15-11 of the Draft EIS, the second sentence should be deleted.

- On Page 3.15-13 of the Draft EIS, the term “see Figure 3.1-6” should be deleted and replaced with the following text.

(see Figure 3.15-6)

- Figure 3.15-7 of the Draft EIS has been revised. The new Figure 3.15-7 with the new title “Projected 2004 PM Peak-Hour and Average Weekday Traffic Volumes During Peak Construction Activities” is included at the end of this section.

3.15.5 Mitigation Measures

- On Page 3.15-23 of the Draft EIS, the first bullet in the list under this heading should be deleted and replaced with the following text.

A traffic signal would be installed at the intersection of Grandview Road (SR-548)/Portal Way that is synchronized with the existing Burlington Northern Railroad signals. This measure is part of the Letter of Understanding (LOU) No. 66 dated December 4, 2003 between the Applicant and WSDOT.

- On Page 3.15-23 of the Draft EIS, the second bullet in the list under this heading should be deleted and replaced with the following text.

The Applicant would ensure that agreed upon mitigation measures would be completed and fully operational within 260 days of the Site Release or prior to peak construction.

- On Page 3.15-23 of the Draft EIS, the last sentence of the last bullet in the list under this heading should be deleted and replaced with the following text.

Delivery of heavy or oversized equipment would be by road or rail, as practical.

- On Page 3.15-23 of the Draft EIS, the heading titled "Additional Recommended Mitigation Measures" and the text below it, which continues onto the next page, should be deleted.

Figure 3.15-7

3.16 HEALTH AND SAFETY

Updates to this section of the Draft EIS resulted from additional information provided by the Applicant and information obtained in response to public comments on the Draft EIS. Updated text and revisions to Table 3.16-5 in this section based on the new information are presented below.

- On Page 3.16-1 in the Draft EIS, the last two sentences in the second paragraph should be deleted and replaced with the following text.

A Health and Safety Plan and Emergency and Security Plan would be developed for the cogeneration facility. These plans would be developed in coordination with the refinery's existing plans. Where additional sources of information have been used to evaluate the potential impacts associated with the proposal, those sources have been cited.

- In Table 3.16-1 on Page 3.16-2, the tenth bullet under the subheading "Applicable Industry Requirements" should be deleted and replaced with the following.

- Uniform Building Code 97;

3.16.2 Impacts of the Proposed Action

- On Page 3.16-15 in the Draft EIS, the following text should be added after the fourth paragraph.

As described in Section 3.15.2, trucks would deliver anhydrous ammonia to the cogeneration facility approximately twice a month; currently ammonia is delivered to the refinery twice a year. It is anticipated that the additional ammonia needed for the Selective Catalytic Reduction (SCR) would be supplied by local suppliers, and delivery trucks would use the same delivery routes as used today. All ammonia delivery trucks would need to follow appropriate federal, state, and local permitting requirements. In addition, the cogeneration facility's Risk Management Plan would identify and describe actions to be taken by the refinery and public emergency response personnel in case of an accidental spill or traffic accident involving the release of ammonia to the environment.

- On Page 3.16-17 in the Draft EIS, the second full paragraph should be deleted and replaced with the following text.

Applicant-proposed mitigation measures to be implemented in case of an accidental ammonia release are summarized in Section 3.16.5. Additional modeling would be performed for the Risk Management Plan to identify the probable area of exposure to ammonia at a concentration of 200 ppm or higher under a realistic release scenario. This modeling, which would be done to assess health impacts from such an exposure, is not required at this time.

- On Page 3.16-20 in the Draft EIS, the following text should be added before the last row in Table 3.16-5.

Sodium Bromide	100 to 700 gallons	800 gallons	Cooling water treatment

- After the first paragraph on Page 3.16-21 in the Draft EIS, the following heading and text should be added.

Cooling Tower Inhibitor

Biocides would be added to the cooling water to control bacterial formation in the cooling tower, and thereby prevent or reduce the formation of *Legionella* bacteria. A mixture of bleach (15% aqueous solution of sodium hypochlorite) and sodium bromide (40% aqueous solution) would be added to the circulating water in a ration of 10:1. This is the same biocide formulation that is used in the existing refinery cooling towers. Generally, industrial cooling systems are less prone to bacterial formation because they operate continuously, unlike indoor Heating/Ventilation/Air - Conditioning (HVAC) systems that have been most prone to outbreaks of Legionnaires' disease. Continuous operation keeps the biocides well mixed in the circulating water and reduces stagnant conditions where bacteria can develop and reproduce.

- After the third paragraph on Page 3.16-21 in the Draft EIS, the following heading and text should be added.

Air Emissions

A discussion of potential health impacts resulting from inhalation of $PM_{2.5}$ can be found in Section 3.2.3 of the Final EIS.

CHAPTER 4: REFERENCES

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Adjudicative Hearing Exhibits (December 8, 9, 10, and 11, 2003)

- Exhibit 2.1 Preliminary Approval Notice of Construction and Prevention of Significant Deterioration, Permit No. EFSEC/2002-01. Includes Technical Support Document.
- Exhibit 3.0 State Waste Discharge Permit WA-ST-7441, Draft.
- Exhibit 3.1 Fact Sheet BP Cherry Point Cogeneration Project State Waste Discharge Permit WA-ST-7441.
- Exhibit 20.0. Applicant's Prefiled Direct Testimony, Witness Mark S. Moore. Includes Attachments 20.1 and 20.2.
- Exhibit 20R.0. Applicant's Prefiled Rebuttal Testimony, Witness Mark S. Moore.
- Exhibit 21.0. Applicant's Prefiled Direct Testimony, Witness Michael D. Torpey. Includes Attachments 21.1, 21.2, 21.3, and 21.4.
- Exhibit 21R.0. Applicant's Prefiled Rebuttal Testimony, Witness Michael D. Torpey.
- Exhibit 22.0. Applicant's Prefiled Direct Testimony, Witness Brian R. Phillips. Includes Attachments 22.1, 22.2, and 22.3.
- Exhibit 22R.0. Applicant's Prefiled Rebuttal Testimony, Witness Brian R. Phillips.
- Exhibit 23.0. Applicant's Prefiled Direct Testimony, Witness W. David Montgomery, Ph.D. Includes Attachments 23.1, 23.2, 23.3, and 23.4.

- Exhibit 24.0. Applicant’s Prefiled Direct Testimony, Witness David M. Hessler, P.E. Includes Attachments 24.1, 24.2, 24.3, 24.4, and 24.5.
- Exhibit 24R.0. Applicant’s Prefiled Rebuttal Testimony, Witness David M. Hessler, P.E. Includes Attachments 24.1, 24.2, 24.3, 24.4, 24.5, 24.6, and 24.7.
- Exhibit 25.0. Applicant’s Prefiled Direct Testimony, Witness Thomas R. Anderson.
- Exhibit 26.0. Applicant’s Prefiled Direct Testimony, Witness William P. Martin. Includes Attachments 26.1, 26.2, and 26.3.
- Exhibit 27.0. Applicant’s Prefiled Direct Testimony, Witness Michael A. Kyte. Includes Attachment 27.1.
- Exhibit 27R.0. Applicant’s Prefiled Rebuttal Testimony, Witness Michael A. Kyte.
- Exhibit 28.0. Applicant’s Prefiled Direct Testimony, Witness A. David Every, Ph.D. Includes Attachments 28.1. 28.2, 28.3, 28.4, 28.5, and 28.6.
- Exhibit 28R.0. Applicant’s Prefiled Rebuttal Testimony, Witness A. David Every.
- Exhibit 29.0. Applicant’s Prefiled Direct Testimony, Witness James W. Litchfield. Includes Attachment 29.1.
- Exhibit 30R.0. Applicant’s Prefiled Rebuttal Testimony, Witness Donald Davies, Ph.D. Includes Attachment 30R.1.
- Exhibit 31R.0. Applicant’s Prefiled Rebuttal Testimony, Witness Ann M. Eissinger. Includes Attachment 31R.1.
- Exhibit 32R.0. Applicant’s Prefiled Rebuttal Testimony, Witness Sanjeev R. Malushte, Ph.D., S.E., P.E. (Civil), P.E. (Mechanical), C. Eng., F.ASCE. Includes Attachment 32R.1.
- Exhibit 33R.0. Applicant’s Prefiled Rebuttal Testimony, Witness Dennis R. Bays.
- Exhibit 34R.0. Applicant’s Prefiled Rebuttal Testimony, Witness David H. Enger. Includes Attachment 34R.1.
- Exhibit 40.0. Whatcom County’s Prefiled Testimony, Witness #40, Bill Elfo.
- Exhibit 41.0. Whatcom County’s Prefiled Testimony, Witness #41, Neil Clement.
- Exhibit 42.0. Whatcom County’s Prefiled Testimony, Witness #42, Dr. Kate Stenberg. Includes Attachment 42.1.
- Exhibit 43.0. Whatcom County’s Prefiled Testimony, Witness #43, Douglas Goldthorp.
- Exhibit 44.0. Whatcom County’s Prefiled Testimony, Witness #44, Hal Hart.
- Exhibit 45.0. Whatcom County’s Prefiled Testimony, Witness #45, Paul Wierzba, Ph.D., P. Eng. Includes Attachments 45.1, 45.3, 45.4, and 45.5.
- Exhibit 46.0. Whatcom County’s Prefiled Testimony, Witness #46, Rodney Vandersypen. Includes Attachment 46.1.
- Exhibit 47.0. Whatcom County’s Prefiled Testimony, Witness #47, Kraig Olason.
- Exhibit 48.0. Whatcom County’s Prefiled Testimony, Witness #48, Jane Koenig, Ph.D. Includes Attachments 48.1, 48.2, 48.3, 48.4, 48.5, 48.6, and 48.7.

CHAPTER 5: ACRONYMS AND ABBREVIATIONS

$\mu g/m^3$	micrograms per cubic meter
AASHTO	American Association of State Highway Transportation Officials
ACC	air-cooled condensing
ADT	average daily traffic
AHPA	Archaeological and Historic Preservation Act
AIHA	American Industrial Hygiene Association
ANSI	American National Standards Institute
APE	Area of Potential Effect
Applicant	BP West Coast Products, LLC
AQI	air quality index
AQRV	air quality related values
ASC	Application for Site Certification
ASILs	Acceptable Source Impact Levels
B&O	business and occupation
BACT	Best Available Control Technology
BE	Biological Evaluation
BFW	boiler feedwater
BMPs	Best Management Practices
BNSF	Burlington Northern Santa Fe
BOD	Biochemical Oxygen Demand
Bonneville	Bonneville Power Administration
BP	BP West Coast Products, LLC
Btu/kWh	British thermal units per kilowatt hour
CAA	Clean Air Act
CB	citizens band
CEQ	Council on Environmental Quality
CERCLIS	Comprehensive Environmental Response, Compensation, and Liability Information System
CFR	Code of Federal Regulations
cfs	cubic feet per second
CGTs	combustion gas turbine generators
CMA	Compensatory Mitigation Area
CO	carbon monoxide
COD	Chemical Oxygen Demand
Corps	U.S. Army Corps of Engineers
CPR	cardiopulmonary resuscitation
CRGNSA	Columbia River Gorge National Scenic Area
dB	decibels
dbh	diameter at breast height
DOT	U.S. Department of Transportation
Dth/d	decatherms per day
Ecology	Washington Department of Ecology
EFSEC	Washington State Energy Facility Site Evaluation Council
EHSP	Environmental, Health, and Safety Program

EIA	Energy Information Administration
EIS	Environmental Impact Statement
EMF	electromagnetic fields
EMI	electromagnetic interference
EOs	Executive Orders
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EPP	Emergency Preparedness Plan
ERC	emission reduction credit
ERPG	Emergency Response Planning Guidelines
ESA	Endangered Species Act
ESU	Evolutionarily Significant Unit
FAA	Federal Aviation Administration
FCRTS	Federal Columbia River Transmission System
FEMA	Federal Emergency Management Agency
Ferndale pipeline	Arco Western Natural Gas Pipeline
FERO	Fire Emergency Response Operations
FM	frequency modulated
FPPA	Farmland Protection Policies Act
GHG	greenhouse gas
GLO	General Land Office
gpm	gallons per minute
GPT	Gateway Pacific Terminal
GSX	Georgia Strait Crossing
GTN	Gas Transmission, Northwest
GVRD	Greater Vancouver Regional District
H_2SO_4	sulfuric acid mist
HAP	hazardous air pollutants
HHV	Higher Heat Value
HII	Heavy Impact Industrial
horsepower	hp
HRSGs	heat recovery steam generators
IPCC	Intergovernmental Panel on Climate Change
ISC	Industrial Source Complex
ISOM project	gasoline isomerization or Clean Fuels Project
kHz	kilohertz
kpph	thousand pounds per hour
kV	kilovolt
kV/m	kilovolts per meter
kW	kilowatt
L&I	Washington Department of Labor and Industries
lbs/kWhr	pounds per kilowatt-hour
LII	Light Impact Industrial
LNG	liquid natural gas
LOS	level-of-service
LOU	Letter of Understanding

MACT	Maximum Available Control Technology
MBtu	million British thermal units
MDth/day	million decatherms per day
mG	milligauss
MMlb	million pounds
MMTCE	million metric tons of carbon equivalents
MP	milepost
MSDS	Material Safety Data Sheets
MSL	mean sea level
MVA	million volt amp
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NAGPRA	Native American Graves Protection and Repatriation Act
NEPA	National Environmental Policy Act
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NHPA	National Historic Preservation Act
NO_2	nitrogen dioxide
NOAA	National Oceanic and Atmospheric Administration
NOx	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NRCS	Natural Resources Conservation Service
NSPS	New Source Performance Standards
NSR	New Source Review
NWAPA	Northwest Air Pollution Authority
NWPCC	Northwest Power and Conservation Council
O_3	ozone
OAHP	Office of Archaeology and Historic Preservation
OSHA	Occupational Safety and Health Administration
OTED	Washington State Office of Trade and Economic Development
Pb	lead
PEM	palustrine emergent
PFO	palustrine forested
PFOC	seasonally flooded palustrine forested
PG&E	PG&E National Energy Group
PGA	peak ground acceleration
PM	particulate matter
PM_{10}	particulate matter less than 10 micrometers in size
$PM_{2.5}$	particulate matter less than 2.5 micrometers in size
ppb	parts per billion
ppm	parts per million
ppmdv	parts per million dry volume
PSD	Prevention of Significant Deterioration
PSE	Puget Sound Energy
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge

PSS	Potential Site Study
PSS	palustrine scrub-shrub
PSSA	temporarily flooded palustrine scrub-scrub
PUD	Whatcom County Public Utility District No. 1
RAS	Remedial Action Scheme
RCW	Revised Code of Washington
RI	Radio Interference
RMP	Risk Management Plan
ROD	Record of Decision
ROW	right-of-way
SCF	standard cubic feet
SCR	selective catalytic reduction
SE2	Sumas Energy 2 Generation Facility
SEPA	State Environmental Policy Act
SILs	Significant Impact Levels
SO_2	sulfur dioxide
SPCC	Spill Prevention Control and Countermeasures
SQER	Small Quantity Emissions Rate
STG	steam turbine generator
SWPP	Stormwater Pollution Prevention
TAP	toxic air pollutant
tcf	trillion cubic feet
TESC	Temporary Erosion and Sedimentation Control
TMDL	Total Maximum Daily Load
tpy	tons per year
TransCanada	Alberta Natural Gas Pipeline
TSP	total suspended particulate
TSS	total suspended solids
TVI	television interference
UGA	Urban Growth Area
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VOC	volatile organic compounds
WAAQS	Washington Ambient Air Quality Standards
WAC	Washington Administrative Code
WDFW	Washington Department of Fish and Wildlife
WDNR	Washington Department of Natural Resources
WECC	Western Electricity Coordinating Council
WRIA	Water Resource Inventory Area
WRAT	Water Right Application Tracking
WSCC	Western System Coordinating Council
WSDOT	Washington State Department of Transportation
WUTC	Washington Utilities and Transportation Commission
WWTP	Birch Bay Wastewater Treatment Plant
ZID	Zone of Initial Dilution

CHAPTER 6: LIST OF PREPARERS

The lead agencies for the BP Cherry Point Cogeneration Project EIS are Bonneville and EFSEC. The EIS was written with the technical assistance of Shapiro and Associates, Inc. Individuals responsible for preparing the EIS are listed below.

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