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

August 20, 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.

Allen J. Fiksdal
Energy Facility Site Evaluation Council

Thomas C. McKinney
Bonneville Power Administration

TABLE OF CONTENTS

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.

Contact for Additional Information:

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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
360-956-2121

Whatcom County Library
Attn: Kathy Richardson
610 Third Street
Blaine, WA 98230

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

Semiahmoo Library
#200 1815 152 Street
Surrey, BC V4A 9Y9
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.

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.

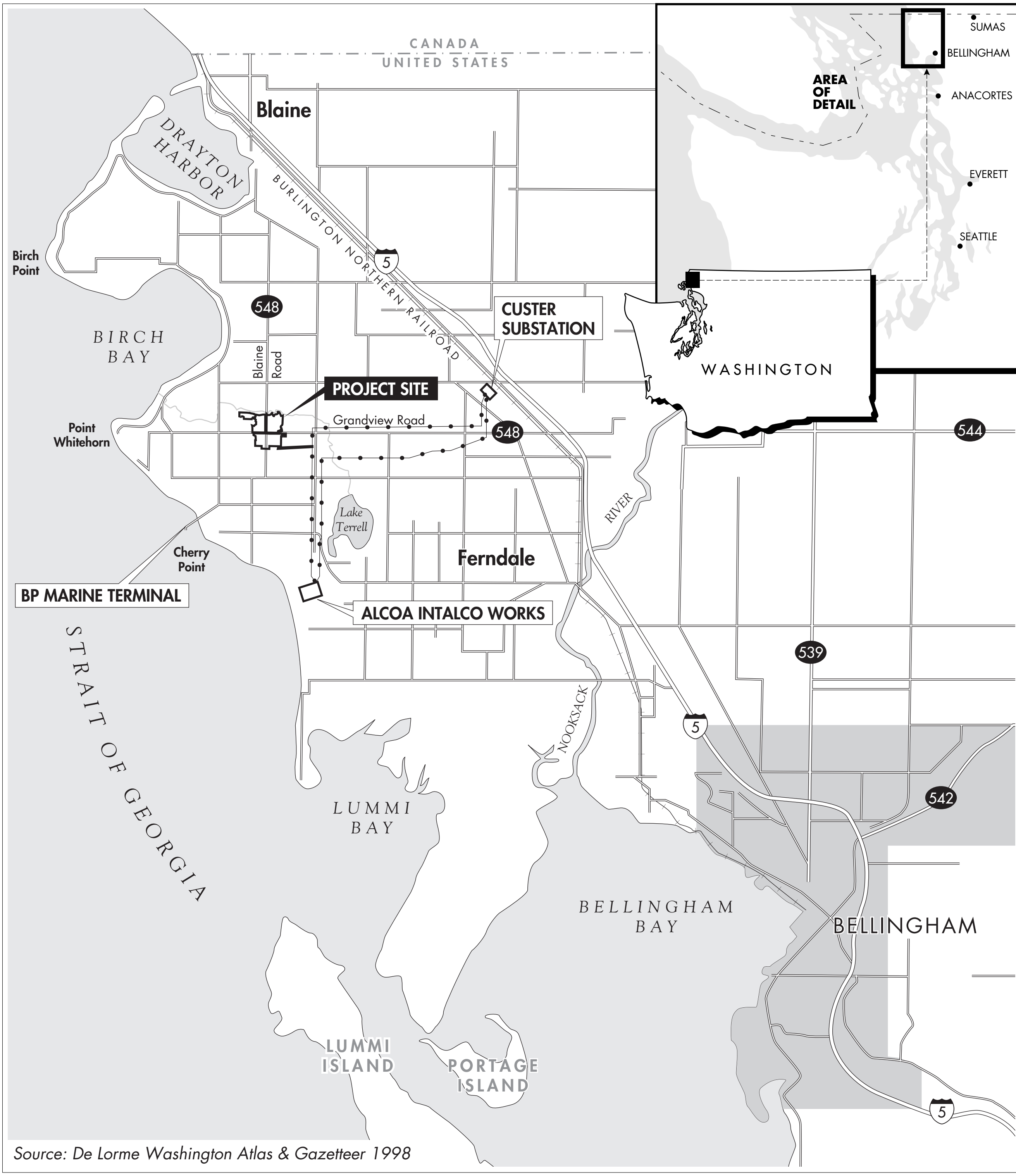
The cogeneration facility and its ancillary infrastructure would provide steam and 85 MW of electricity to meet the operating needs of the refinery and 635 MW of electrical power for local and regional consumption. The proposed cogeneration facility would be located between Ferndale and Blaine in northwestern 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.



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0 3

Approximate Scale in Miles

transmission line

FIGURE 1-1

PROJECT VICINITY MAP

BP CHERRY POINT COGENERATION EIS

SHAPIRO & ASSOCIATES, INC.

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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

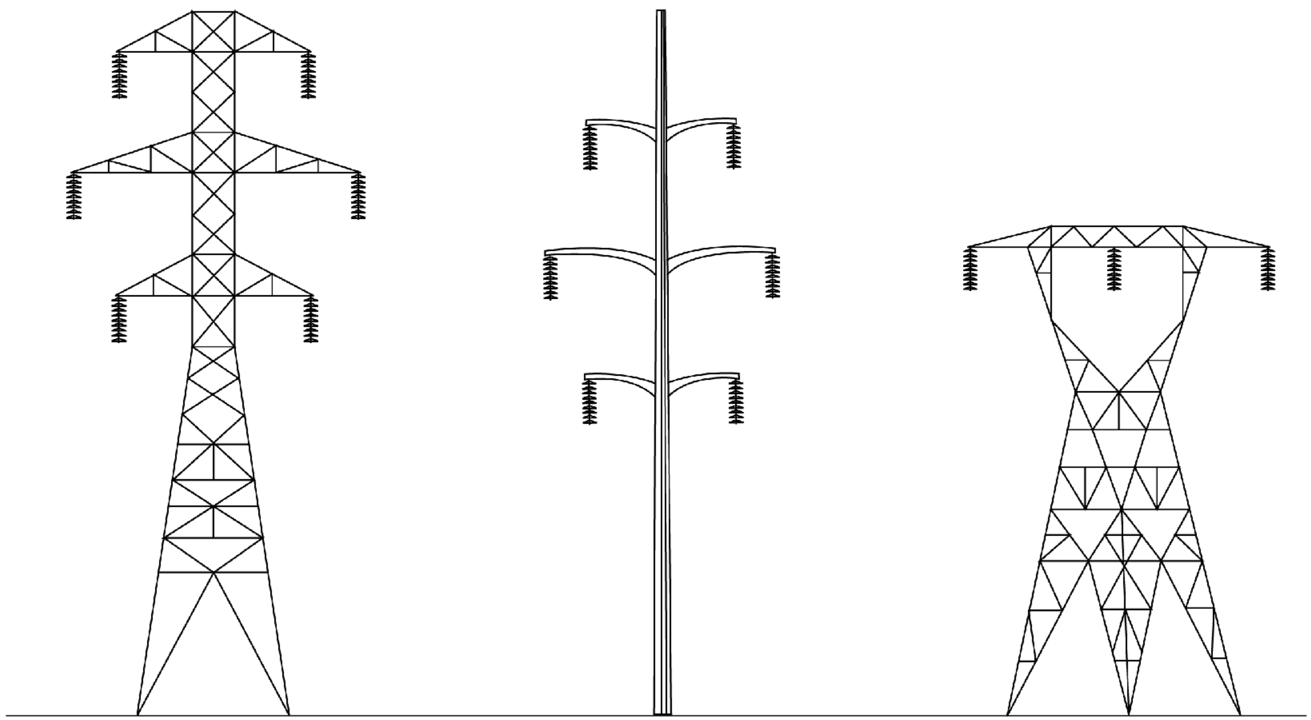
Alternative Sites

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.



230 kV Steel Lattice
Double Circuit
Average Height 120'
Average Span 1150'

230 kV Steel Pole
Double Circuit
Average Height 120'
Average Span 900'

230 kV Steel Lattice
Single Circuit
Average Height 85'
Average Span 1150'

Source: Bonneville Power Administration 2003

FIGURE 1-2

NOT TO SCALE

TYPICAL TRANSMISSION TOWER DESIGNS

BP CHERRY POINT COGENERATION EIS

SHAPIRO & ASSOCIATES, INC.

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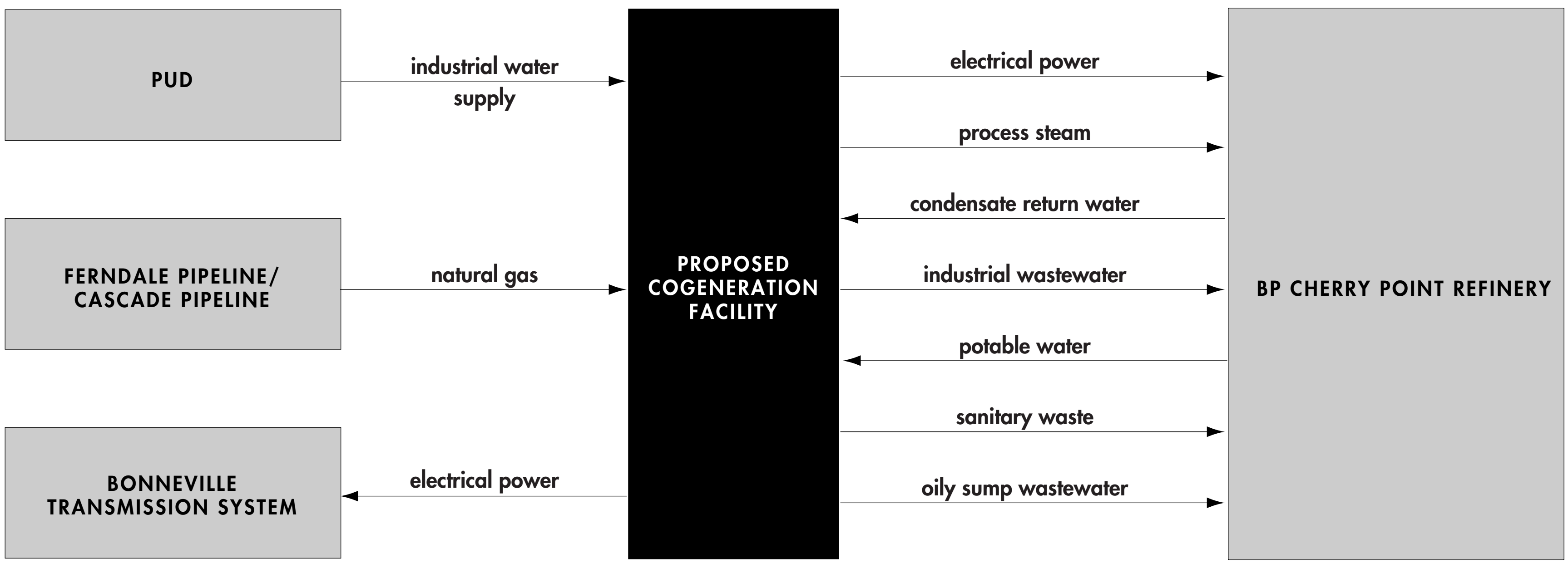


Source: BP 2002

FIGURE 1-3

COGENERATION FACILITY INFRASTRUCTURE AND REFINERY INTERCONNECTIONS

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

Site 2

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.

Site 3

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

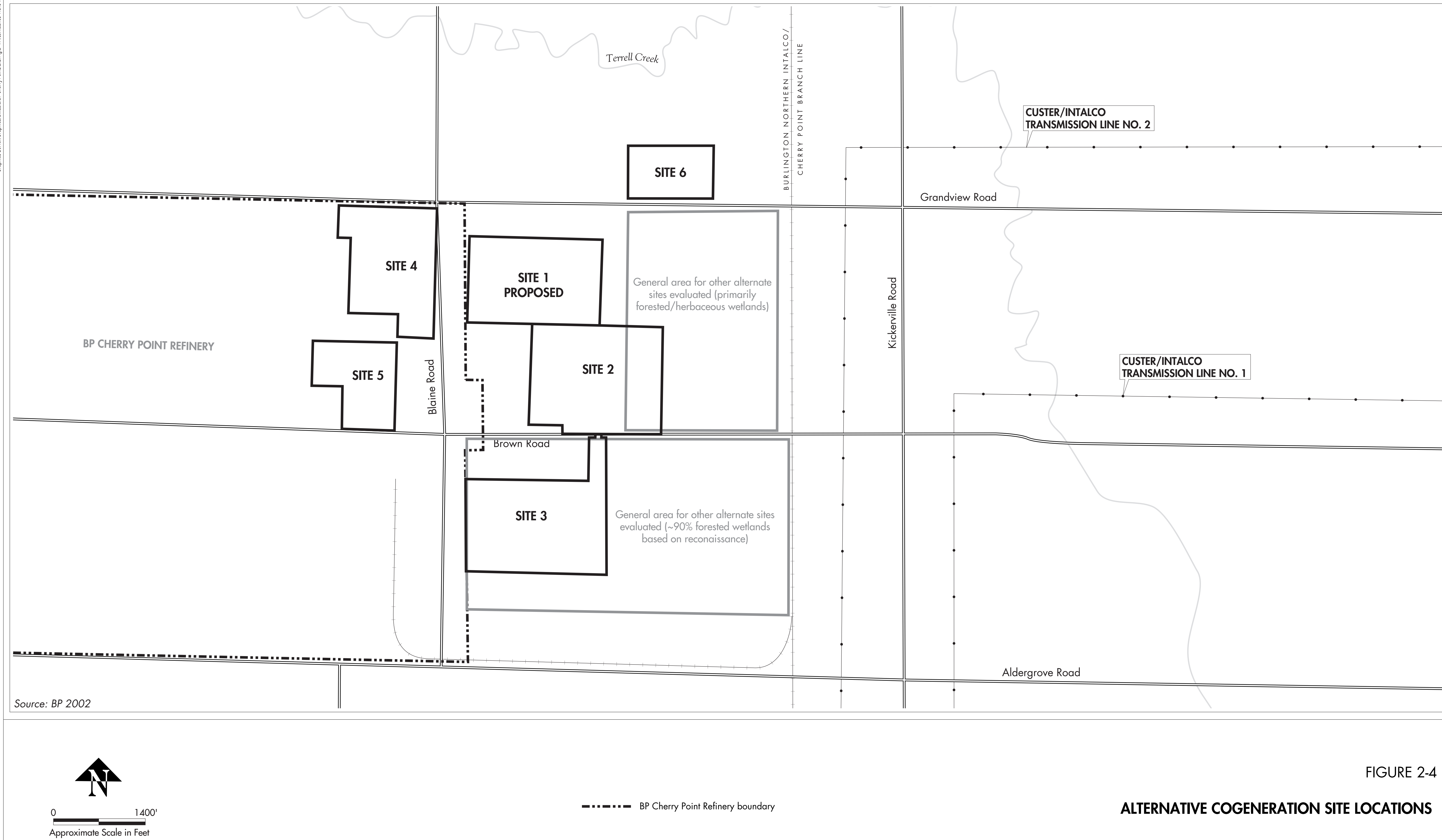


FIGURE 2-4

ALTERNATIVE COGENERATION SITE LOCATIONS

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	$\mu g/m^3$	ppm	$\mu g/m^3$	ppm	$\mu g/m^3$	$\mu g/m^3$	$\mu g/m^3$	$\mu g/m^3$	$\mu g/m^3$
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: $\mu g/m^3$ = 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

United States

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 (µg/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 (µg/m³)[4]		ASIL (µg/m³)[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 µg/m³

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 ($\mu g/m^3$)			Most Stringent Canadian Objective or Standard ($\mu g/m^3$)
		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 $\mu g/m^{3.}$

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 ($\mu g/m^3$)			Lower of WAAQS or NAAQS ($\mu g/m^3$)
		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 ($\mu g/m^3$)			Most Stringent Canadian Objective or Standard ($\mu g/m^3$)
		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

<u>ISOM Toxic Pollutant Emissions</u>

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.

Operating Scenarios

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/m^3)				Most Stringent of Canadian Objective (μg/m^3)
		Maximum Existing Background Concentration (μg/m^3) [1]	Modeled Maximum Impacts of Sumas Energy 2 (μg/m^3) [2]	Modeled Maximum Impacts of BP Cogeneration Facility in Abbotsford (μg/m^3)	Cumulative Impact (μg/m^3)	
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/m^3)				Most Stringent of NAAQS or WAAQS (μg/m^3)
		Maximum Existing Background Concentration (μg/m^3) [1]	Modeled Maximum Impacts of Sumas Energy 2 (μg/m^3) [2]	Modeled Maximum Impacts of BP Cogeneration Facility in Sumas (μg/m^3)	Cumulative Impact (μg/m^3)	
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

Mitigation Proposed by the Applicant

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

Regulated Air Emissions

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.

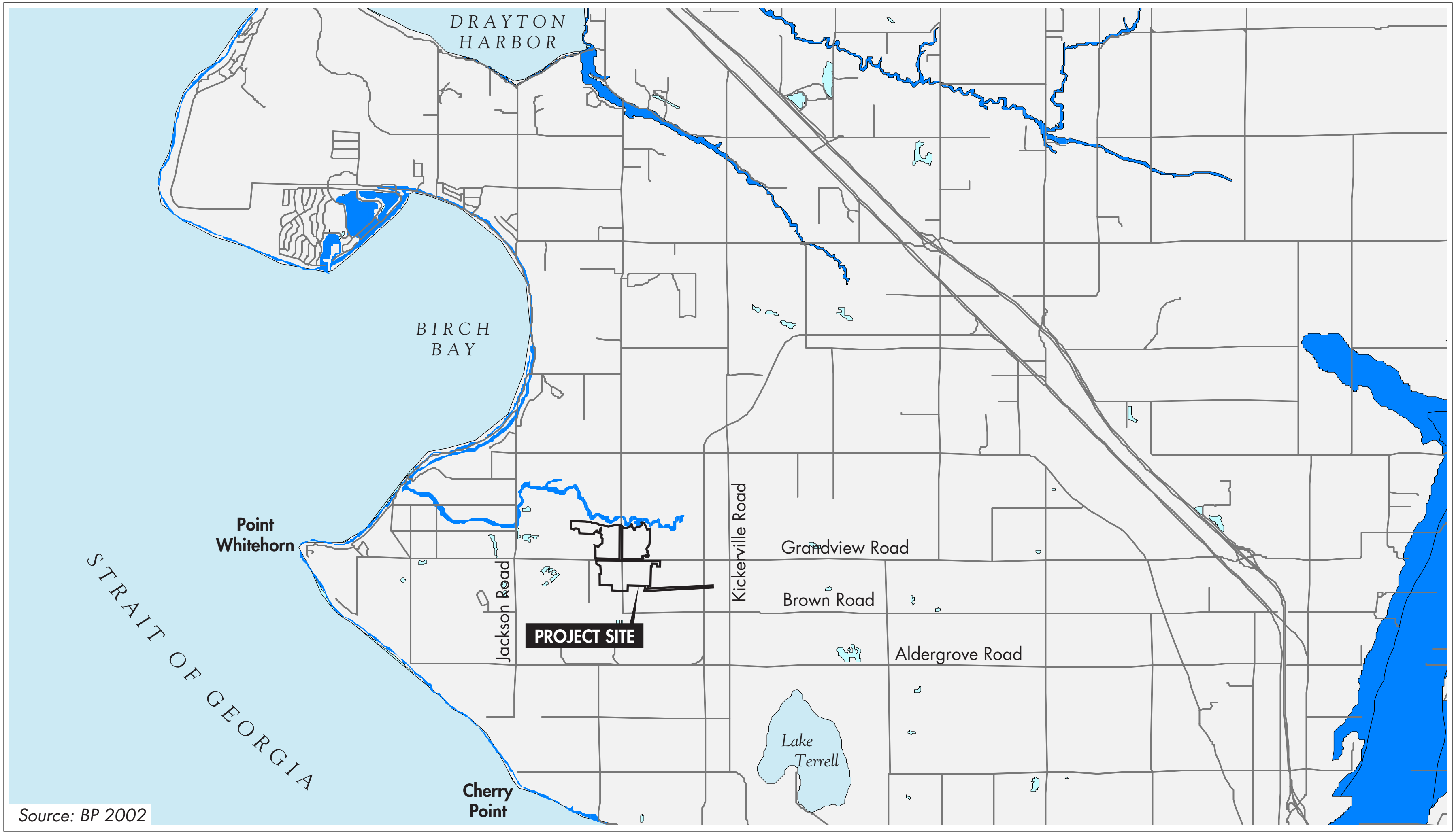
3.3.5 Mitigation Measures

- 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.



100-year floodplain

Zone C: areas outside 500-year floodplain

FIGURE 3.3-4

FLOODPLAINS

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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 (^oF)	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.

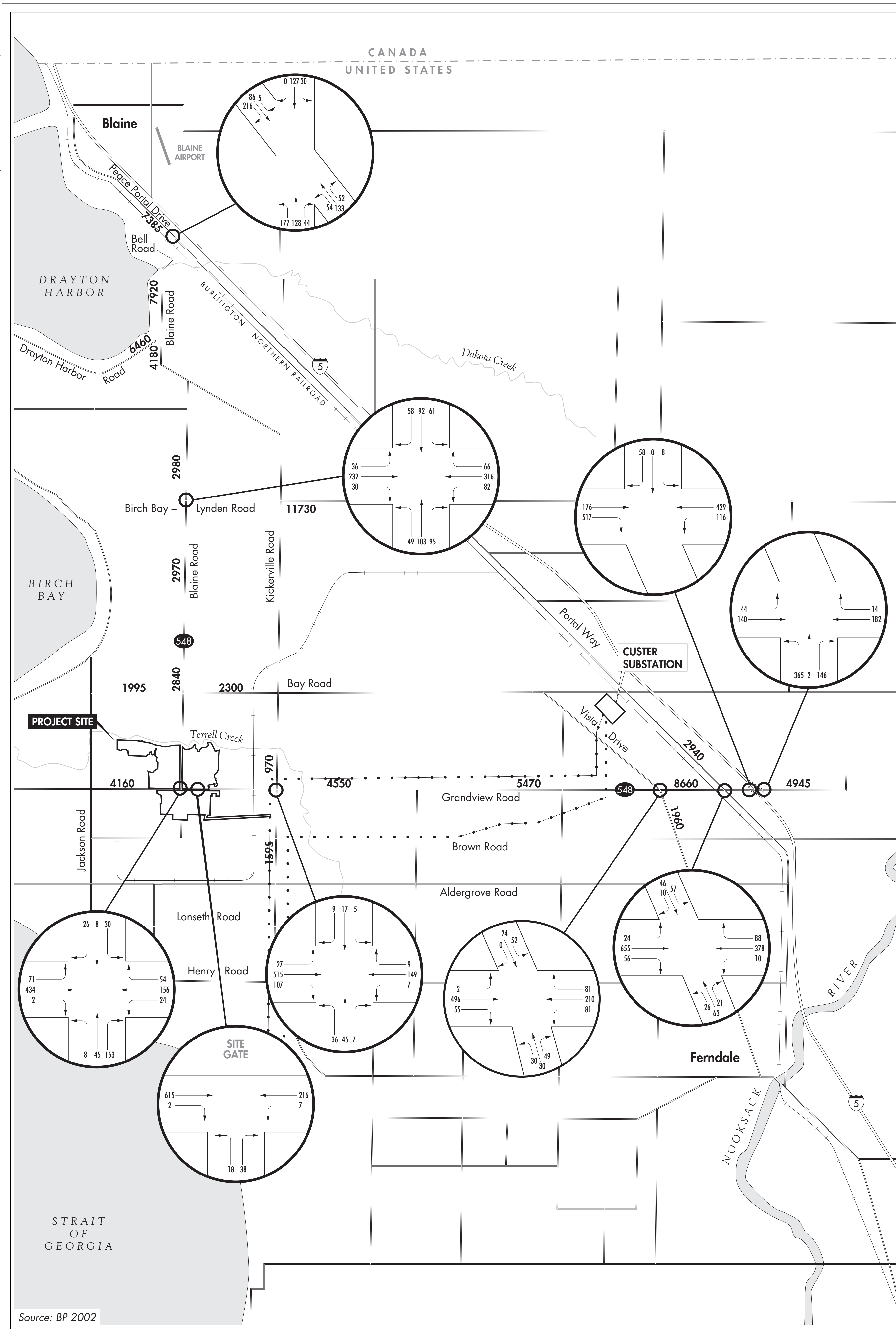
- On Page 3.15-23 of the Draft EIS, the second bullet in the list under this heading should be deleted and replaced with the following text.

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.



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0 1
Approximate Scale in Miles

295 — PM peak-hour traffic volume and direction

1200 average weekday traffic volume

•—•—• transmission line

FIGURE 3.15-7

PROJECTED 2004 PM PEAK-HOUR AND AVERAGE WEEKDAY TRAFFIC VOLUMES DURING PEAK CONSTRUCTION ACTIVITIES

SHAPIRO & ASSOCIATES, INC.

1014003T

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.

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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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REVISED 404 (B) (1) ALTERNATIVES ANALYSIS

BP Cherry Point Cogeneration Project

Prepared for:
BP West Coast Products, LLC

Revised June 29, 2004

URS

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TABLE OF CONTENTS

TABLES

FIGURES

1.0 INTRODUCTION

This Alternatives Analysis replaces the Alternatives Analysis prepared by Golder Associates (Golder Associates 2003) that was submitted to EFSEC as Appendix H-5 of the Revised Application for Site Certification. This replacement incorporates information from the earlier document and provides additional information and analysis.

2.0 PURPOSE AND NEED

The basic purpose of the cogeneration project is to provide a reliable and cost-effective supply of both steam and electricity to the BP Cherry Point refinery and to provide electricity to the regional power grid.

The BP Cherry Point refinery needs significant amounts of steam and electricity to refine and process petroleum products. BP needs a supply of steam and electricity that is both reliable and reasonably priced. Without a reliable source of steam and electricity, the refinery cannot maintain operations, and the refinery satisfies fundamental regional needs for petroleum products. A reliable source of steam and electricity is also needed to operate the refinery safely. Unanticipated interruptions in supply could require the emergency shutdown of refinery operations and the safety risks associated with unplanned shutdowns. BP also needs steam and electricity to be available at a reasonable price. In the past, extreme electricity price volatility has imposed a significant economic cost on the refinery, and over the long term, could threaten the viability of the refinery.

The region also needs additional electricity generation capacity, as demand for electricity continues to grow. The cogeneration project would provide electrical energy for sale into the regional power grid, thus supplying a growing public need for electricity.

In order for the cogeneration project to satisfy the refinery's need for electricity and steam, and the region's need for additional generating capacity, the cogeneration project must be an appropriate size, capable of producing cost-competitive steam and power, located in close proximity to the refinery, and commercially feasible.

The fundamental purpose and need for the laydown areas is to provide temporary construction staging and support areas for the cogeneration project and permanent area for routine maintenance of refinery components. In order to satisfy that purpose and need, the laydown areas must be located in close proximity to the east of the refinery and cogeneration project site, of sufficient size for anticipated activities, and must not compromise security at the refinery.

2.1 RELIABILITY

Refinery operations require significant amounts of both electricity and steam. The BP refinery currently uses approximately 85 MW of electricity, and this requirement is expected to grow in the future. In particular, BP plans to add process units to allow the refinery to produce cleaner gasoline and diesel to comply with clean fuel regulations that will go into effect in 2005 and 2006. BP is currently completing the Isomerization Project, which will produce the cleaner gasoline, and that project is expected to increase electricity demand by approximately 2.5 MW. BP will eventually be installing new equipment to produce cleaner diesel fuel as well. This equipment will further increase the refinery's electricity demand. Although it is too early in the project development to determine the amount of the additional electricity demand, it is likely to be about 2.5 MW more.

The BP refinery also uses a substantial amount of steam. Steam is used to heat materials and to provide pressure to drive pumps and compressors. Four utility boilers currently provide steam to the refinery, each with the capacity to produce 150,000 lbs./hr. of steam for a total capacity of 600,000 lbs./hr. The range of steam production varies greatly with a variety of refinery process conditions, with the current steam requirement averaging 287,000 lbs./hr on an annual basis. The clean gasoline and diesel projects discussed above will increase the refinery's steam requirement. The Isomerization Project will increase the average steam requirement to 510,000 lbs./hr, and a new boiler will be added to provide additional steam capacity. The clean diesel project will increase steam demand further, although it is too early to determine the amount of the additional steam demand.

Maintaining a reliable supply of electricity and steam is necessary from operational, safety, and economic perspectives.

First, a reliable supply of electricity and steam is necessary to maintain operation of the refinery. Without electricity and steam, the refinery cannot operate. Brief power outages or even sudden voltage changes can cause some refinery process units to be shut down temporarily. For example, in March 2004, lightning struck a transmission line near Lynden, Washington, causing a drop in voltage from 115kV to about 25kV. Automatic equipment corrected the problem in about 70 milliseconds, and the closure of breakers on the line caused a second similar dip for 70 milliseconds. This transmission line connects to a substation in common with a transmission line supplying the BP Cherry Point refinery, and those brief power dips caused a calciner hearth and a utility boiler to shut down.

Refinery equipment that must be shut down suddenly without prior planning can require a considerable amount of time to bring back on line. It may require hours, even weeks, to make process units safe to start up after a sudden and unplanned shutdown. Some heavy liquids solidify if allowed to cool. If these liquids solidify inside process equipment such as pipes, vessels, valves and pumps, it is very difficult to remove, clean up and prepare the equipment for startup. Maintaining a constant reliable supply of both electricity and steam is, therefore, critical to maintaining continuous operations at the refinery.

Second, a reliable supply of electricity and steam is necessary to minimize safety risks at the refinery. The refinery has procedures to allow the safe shutdown of process unit operations for sudden and unplanned reasons. However, the restart of equipment following sudden and unplanned shutdowns can present safety risks. For example, a very serious incident occurred at a neighboring refinery, when a sudden loss of electric power resulted from a severe storm and caused the shutdown of steam production and process operations. The sudden shutdown of one process unit resulted in unprocessed material being left inside the equipment. Two days later, the opening of the vessel to discharge the partially cooled material caused the unexpected release of volatile material that caught fire and resulted in the death of six refinery personnel (U.S. Chemical Safety and Hazard Investigation Board 2001). Although these kinds of accidents can be avoided with careful procedures, this accident illustrates the potential risks associated with unplanned shutdowns.

Third, a reliable source of electricity and steam is important to the regional economy. Without steam and electricity, the refinery cannot operate. Interruptions in the production and supply of refined petroleum products cause problems for the regional economy. About one fifth of the vehicles in the state of Washington run on gasoline produced by BP Cherry Point Refinery, and about 80 percent of the jet fuel for Sea-Tac airport comes from the BP refinery. Interruptions in supply would have a major effect on the economy of the region.

The importance of power reliability to the refinery is reflected in the redundant systems currently in place to supply electricity and steam to the refinery. There are four separate electrical power transmission lines feeding the refinery today: two separate transmission lines from the Custer Substation, one transmission line from the Bellingham Substation, and one transmission line from the Puget Sound Energy Point Whitehorn Generating Station. Except for the generating station, any one of the transmission lines by itself could supply the refinery power needs. Likewise, the refinery maintains multiple boilers, so that all need not be operational to satisfy the refinery's demand for steam. Maintaining reliability is fundamental to the operation of the refinery, and improving it when possible is prudent.

In order to ensure a reliable supply of both electricity and steam, BP has designed the cogeneration project to have three gas-fired turbines, each with a heat recovery steam generator (HRSG) that can provide steam directly to the refinery or to the cogeneration unit's steam turbine. Having three gas turbines and HRSGs will ensure a continuous supply of steam and electricity to the refinery, even if one gas turbine were off-line for maintenance and a second turbine shut down unexpectedly.

2.2 COST-EFFECTIVENESS

BP needs to obtain electricity and steam for the refinery at a reasonable price. The average annual electricity cost has been $21 million. In 2000 and 2001, however, the cost of electricity for the refinery was more than triple the 10-year average cost, and the cost for those two years combined was more than $100 million above the 10-year average. On a long-term basis, such electricity costs would threaten the economic viability of the refinery.

The proposed cogeneration facility is cost-effective because the combined cost of electricity and steam it would provide to the refinery is expected to be at or below the typical average combined cost of buying electricity from the regional grid and producing steam from stand-alone boilers. In this region, the cost of both electricity and gas is typically lower in the late spring and summer, and the cogeneration/refinery operation can adapt to the price.

The region also requires additional electrical generating facilities that are capable of generating electricity at a reasonable and competitive price. As a privately-financed project, the cogeneration project can only go forward if it is able to compete successfully in the regional power market by selling power at a competitive price. Most of the base-load power in the region is provided by hydroelectric, nuclear, and coal power plants, but new units of those types of plants are unlikely to be added to the supply. Only gas-fired power plants are likely to be built, and only the most efficient are competitive for base-load power. Other plants with higher operating costs can operate economically only during peak demand periods when prices are higher. An important part of the ability of the project to operate competitively in a base-load market is that, as a cogeneration plant, this facility will be one of the most fuel-efficient gas-fired power plants available.

The concept of cogeneration is fundamental to efficiency, because it allows steam to be generated once and used at least twice. The power plant will be a combined cycle plant with water cooling for greatest efficiency. A stand-alone power plant would have to condense 100% of the low-pressure steam from the steam turbine into water in order to pump it back into the heat recovery steam generators (HRSGs). The heat in this low-pressure steam is then lost to the atmosphere. Cogeneration allows part of this heat to be used in refinery processes. The steam sent to the refinery would be used both to heat and to move oil and then once it is used, the condensed steam would be pumped back to the cogeneration plant to be reused to make more steam. The steam that is provided by the cogeneration project allows the refinery to discontinue the production of steam in the utility boilers. The steam delivered to the refinery from the cogeneration plant will be delivered as though it were being produced at nearly 100% efficiency. The existing boilers produce steam at a range of about 70% to 83% efficiency. The refinery is constantly reviewing energy usage by comparing current energy usage to a number called the Energy Intensity Index (EII.) The cogeneration steam will help lower the refinery EII. With the cogeneration plant in place, the three existing least efficient boilers at the refinery will be decommissioned.

2.3 SIZE OF FACILITY

The size and configuration of the proposed cogeneration facility were determined primarily by two factors. First, BP requires a redundant supply of steam. Given the importance of steam reliability described above, BP designed the cogeneration project with three separate generating units, each sized so that it could provide required steam to the refinery even if one unit were down for maintenance and a second unit were shut down unexpectedly. Second, the project must be cost-effective and capable of competing successfully in the regional electricity market as a continuously-operating or base-load facility.

Although a smaller three-turbine facility (utilizing smaller turbines) could provide a triple-redundant supply of steam to the refinery, it would not be cost-effective. The capital costs of a generating facility are not linear in relation to the facility's output. On the contrary, larger turbines are generally more efficient, and a substantial share of the costs associated with a larger facility are also incurred in connection with a smaller facility. The economies of scale are such that the cost per megawatt of electricity generated declines as the size of the facility increases. This is particularly true with a cogeneration facility, which requires significant infrastructure to integrate the generating facility with the steam host, in this case. BP estimates the cost associated with that infrastructure to be at least $10 million for the proposed cogeneration project. BP has proposed a facility of a size that will take advantage of the economies of scale and spread the cogeneration infrastructure costs so that it can provide cost-effective steam and electricity to the refinery and compete in the regional electric market.

Three General Electric 7 FA turbines (nominal 174 MW each) and one steam turbine (nominal 243 MW, but only 216 MW when 510,000 lbs per hour of steam are being delivered) were used to develop base case economics for the project. The combination would produce a nominal total of 720 megawatts (MW). The actual output is less than the individual ratings because the power plant uses 18 MW in its operation. Smaller turbines available as options are less efficient and would reduce the return to investors enough that their selection would not be cost-effective and would make the project impracticable.

2.4 CRITERIA FOR EVALUATING PRACTICABLE LOCATIONS

Potential locations for the cogeneration plant and laydown areas may be rendered impracticable as a result of cost, technology or logistical considerations [40 C.F.R. § 230.3(q)]. Four specific parameters that may render sites impracticable for use as a cogeneration project site or laydown area as a result of associated cost, technology or logistical limitations are size, proximity to the refinery, security, and accessibility. Each of these limiting parameters is described below.

2.4.1 Size

The location of both the cogeneration plant and associated laydown areas must be of the appropriate size to accommodate the facility and the required construction activities. Given the available technology and associated equipment required for a cogeneration facility of the size needed, BP has determined that a site of at least 33 acres is required.

BP has designed the plant configuration to be as compact as possible so that the footprint, the materials of construction, the interconnections with the refinery and associated costs are minimized. However, an equally important and competing consideration is that the plant components must be spaced far enough apart to allow for maintenance. BP has balanced these two considerations against one another and proposed a configuration of the facility that will occupy approximately 33 acres and utilize approximately 33 acres for construction laydown.

The 33-acre project site is typical for this type of facility. Similar power plants occupy 30 to 40 acres. For example, the 750 MW Pastoria Energy Facility in California has a 31-acre site, (California Energy Commission 2000) and the 850 MW Mercer Ranch project proposal in Washington had a 40-acre site (EFSEC 2000). Two larger power plant projects proposed in Washington (Starbuck and Wallula) have sites of 40 and 97 acres, respectively (Starbuck Power Company 2001, Wallula Generation 2001). Three recently permitted combustion turbine power projects in Washington (Chehalis, Satsop, and Sumas), each with two turbine units, have project sites ranging from 20 to 33 acres in size (Chehalis Power 1994, Duke Energy 1994, SE2 2001).

Fifteen to 20 acres of construction laydown area are required for the materials and assembly of the major components. Different contractors do different parts, and construction schedules require that several different components be in progress at once in order for each to be ready when required to fit into or be connected to others. In addition, each contractor requires office space and parking. Hundreds of workers, vendors, and delivery people are at the site at the same time, and parking and security have to be provided to accommodate the peaks.

Logistical considerations require at least 33 acres of laydown area for cogeneration project construction. Table 1 shows the cogeneration project construction laydown area uses and approximate acreage required for each use during peak construction.

Table 1
Construction Laydown Uses and Area

Item	Estimated Acreage Requirement[1]
Gas Turbines	4
Steam Turbine	1.5
HRSGs	8
Cooling Tower	1
Structural Backfill	2
Civil Materials	1.5
Structural Steel	2.5
Misc. Equipment	1
Piping Materials	2.5
Electrical Bulks	1.5
Electrical Cable	1
Receiving area	0.5
Warehouse	0.5
Small Construction Equipment	0.5
Trailer Complex	2.5
Craft Parking	2.5
Total	33

[1] These acres are used for planning purposes, but the actual use of many of the acres includes several different functions during construction. Some functions have area requirements that vary over time.

The laydown area requirements for the construction of the cogeneration project total 33 acres in addition to the 3 acres of existing contractor parking area. The 3-acre existing contractor parking area was incorporated as area that can be used at times other than turnarounds, reducing the total laydown area from the 36 acres identified in the Revised EFSEC Application to 33 acres and further reducing the wetland fill needed for the laydown use. Eleven acres of the laydown area will be temporary impact areas that can be restored after the construction of the cogeneration project. Twenty-two acres will be permanently impacted either because they are required for cogeneration project facilities or because they will be required for future refinery maintenance activities.

Of the 22 acres permanently required, approximately 4 acres will be occupied by stormwater facilities, roads, and other interconnections between the cogeneration project and the refinery.

Logistical and cost considerations require at least 22 acres of permanent laydown area for refinery maintenance activities, including annual "turnarounds" where one or more major components of the refinery undergo planned refurbishment. These turnarounds involve the dismantling and refurbishment of large equipment. Hundreds of additional workers are involved, and space is needed to move and store equipment and materials. Turnaround activities must be performed quickly and efficiently because refinery operations are temporarily shutdown during these activities. Anything that causes these activities to take longer results in significant opportunity costs to BP and interrupts the region's supply of needed petroleum products. In order to perform turnarounds quickly and efficiently, a significant amount of space is needed. In the past, major turnarounds have utilized up to 45 acres for laydown purposes. Many of the spaces used for turnaround and maintenance activities in the past have and will be taken up by new refinery equipment used to comply with new clean fuel regulations and other changes in refinery operations. Additional space is, therefore, needed for maintenance and turnarounds, and for some functions, it must be in close proximity to the refinery components.

2.4.2 Proximity to Refinery & Related Infrastructure

Technology, logistics, and cost require the cogeneration plant to be located in close proximity to the refinery because of the numerous connections integrating the cogeneration facility with the refinery.

An essential part of the cogeneration project is the delivery of steam to the refinery. The steam must be delivered through insulated pipes and maintained at specific temperature and pressure. Existing technology does not allow steam to be reliably transported more than a few thousand feet (less than a mile) at a constant temperature and pressure.

The actual distance threshold is derived from a complex combination of factors. In order to deliver steam to the refinery in useable form, it must remain superheated to prevent condensation from forming water droplets that could damage turbines. This can be accomplished over a certain increased distance by thicker insulation, but the chance of condensation increases with increasing distance. The steam also must be delivered at a high pressure. This can be accomplished over some distance by increasing the diameter of the pipe. The pressure cannot be allowed to drop substantially because the refinery header pressure must be maintained within a narrow band (about 1 to 2 pounds per square inch above or below 600) in order to overcome significant fluctuations in steam demand. Refinery steam demand fluctuates on a minute-to-minute or hour-to-hour basis as refinery processes and components are started, stopped, or adjusted to produce different products or components of products. The length of pipe required is also longer than the linear distance between the steam source and the refinery because expansion loops are required as part of the design. All of these factors combine to limit the feasible locations for a steam source to those immediately adjacent to the refinery. As the distance increases, the tolerance for changes in conditions that could affect steam delivery temperature, pressure, and rate decreases. In order to maintain reliable steam delivery, the distance is effectively limited to less than 5,000 thousand feet.

The distance of the cogeneration facility from the refinery is also limited by cost and logistical factors. The cogeneration facility will be connected to the refinery in several ways. Pipes will provide steam to the refinery and will return condensate to the cogeneration project. Pipes will transport waste water from the cogeneration facility to the refinery's waste water treatment system. A pipeline connection will transport natural gas from the existing pipeline at the refinery to the cogeneration facility. Transmission lines will transmit electricity from the cogeneration facility to the refinery. The cost issues associated with each of these connections increases with distance. A more distant location would also present logistical difficulties if piping and transmission lines would have to cross roads, rights-of-way, or other utility corridors. For these reasons, BP limited its consideration of alternative sites to those less than 5,000 feet away from the refinery.

Laydown areas must be located near both the cogeneration project site and the refinery. The laydown areas must provide ready access between the laydown area where the major power plant components are assembled and the site where they will be installed. In order to be used for refinery maintenance and turnaround activities, permanent laydown areas must be located near the refinery. They must also be located near needed utilities, such as electrical, water and sewer connections. In many instances, it would not be logistically feasible to transport the large refinery components on public roads to a more distant laydown area.

2.4.3 Security

In order for the cogeneration facility to provide a reliable source of steam and electricity, it must remain secure. Since September 11, 2001, security has been increased at all refineries and power plants in the United States. The cogeneration facility site and laydown areas were selected to facilitate the security measures in place at the refinery. Having the cogeneration plant adjacent to the refinery would allow the existing security fence to be extended around the cogeneration project and would allow the cogeneration facility and the connections between the cogeneration project and the refinery to be incorporated into the security system of the refinery. Keeping the connections within the refinery security system will help protect them both from intentional sabotage and from accidental damage by vehicle damages or other mishap. Any site that would require the steam pipeline to cross a public road is considered unacceptable from a security standpoint. Unlike the other pipelines and piping connections, the steam pipeline must be above-ground. Crossing a public road would make it too vulnerable to intentional or accidental damage. Within the refinery security fence, vehicle safety is tightly enforced and drivers are either employees or are escorted by employees and must pass rigorous safety training.

Locating the cogeneration project laydown and staging areas and the permanent refinery laydown/materials storage sites within the existing or extended refinery security fence maintains security. Locating these laydown areas elsewhere would require significant expense to install and maintain alternative security measures. Logistically, separate secured locations would also present more potential areas of vulnerability.

2.4.4 Accessibility

The primary issues with accessibility are logistical, although efficiency of operation is also extremely important, and efficiency directly translates to cost. Two major considerations of accessibility are the delivery of equipment and materials to the laydown areas and accessibility between the laydown areas and the construction site or the refinery components being refurbished.

The laydown areas must receive large equipment and materials of various sizes and quantities that arrive by highway. Therefore, there must be a direct connection with existing highways. That connection must be separate from the primary entrances to the refinery to keep one operation from compromising another (i.e., refinery operation and construction of the cogeneration facility).

Since the permanent laydown areas will serve two purposes, they must be located so they are accessible to both the refinery and the cogeneration facility. The location of the permanent laydown areas must provide unobstructed access to the refinery components that are regularly refurbished. Some of the components are large enough to be very difficult to move on public roads, and some of the mobile equipment used to move refinery components for maintenance would not be appropriate on public roads. Equipment being moved during periods of high maintenance must be moved within the secured areas of the refinery in order to limit access and maintain efficient operations. The refinery was constructed to accommodate the majority of the turnaround activities in the open space immediately adjacent to the east side of the refinery facilities. Performing these activities at other locations would either not be feasible or at least be more difficult, more time-consuming, more expensive and much more disruptive to on-going refinery operations.

In addition, none of the feasible alternative locations for the cogeneration project are west of the refinery. Therefore, in order to be accessible for both the refinery maintenance operations and the cogeneration construction, the permanent laydown areas must be on the east side of the refinery.

3.0 ALTERNATIVES

The Cogeneration Project is not a water-dependent project. Therefore, alternative actions, alternative sites, and alternative site configurations were considered to determine if they could satisfy the project purpose and need, would be practicable, and would result in less wetland and overall environmental impact.

3.1 ALTERNATIVE ACTIONS

If the cogeneration facility were not built, other actions would have to be taken to attempt to satisfy the purpose and need. The actions associated with each component of the purpose and need are discussed below.

3.1.1 Steam Reliability

A reliable steam supply could be provided by using existing boilers and adding boilers as the refinery steam demand grows. Even the most efficient stand-alone boilers would produce steam less efficiently than the cogeneration project, so more natural gas would be consumed and more air pollutants and greenhouse gases would be emitted per unit of steam produced. No alternate technology is known that would take the place of the boilers. Therefore, while it is possible to supply steam reliably by means other than the cogeneration plant, it can only be done at a higher cost, with greater natural gas use, and with higher air emissions per unit of steam than with cogeneration.

3.1.2 Electricity Reliability and Cost-Effective Supply

There is no alternative that would provide the refinery with a reliable and cost-effective supply of electricity. As long as the refinery's electricity must be purchased on the market, the refinery contributes to the increasing regional demand for electricity and is vulnerable to all the factors that can cause the price and availability of electricity to fluctuate. Very high electrical prices in late 2000 and early 2001 placed the viability of the refinery at risk. In fact, during that period, BP spent over $100 million more than it has historically spent on electricity to operate the refinery. While the price volatility has decreased significantly since then, the projected growth in regional power needs and the variability in hydropower availability will require new power generation to balance supply and demand. The effects of the imbalance in supply and demand could be felt as early as 2006 (Western Electric Coordinating Council 2002). In the current market, BP is not able to obtain a long-term contract for electricity at a reasonable guaranteed price. Power is now typically sold on a "toll" basis, which means essentially a cost-plus basis. The cost of natural gas will drive the cost of electricity whenever the demand above other existing supplies is met by electricity produced by gas-fired power plants. Most of the new combustion turbine power plants have the ability to produce power when the gas price is favorable and not produce it at other times. The cogeneration plant's efficiency advantage will give it a broader effective price range within which it is economical. With the cogeneration project in place, the combined cost of steam and electricity to the refinery is expected to be at the lower end of prices, and the refinery would be supplied directly from the cogeneration plant, which maximizes reliability.

Not building the cogeneration project simply will not accomplish the purpose of providing a reliable and cost-effective electricity and steam supply for the refinery. No other action would do so, and no other known technology would do so. The costs to the refinery would be higher, and the resulting cost of producing gasoline and diesel in the region would also be higher.

Other power facilities could be constructed to satisfy the region's need for additional electrical generating capacity. If the cogeneration project is not built, the power plants most likely to be built to fulfill regional electricity demand will be stand-alone gas-fired combustion turbine plants. Very few large-scale cogeneration facilities are built because a large host willing to enter into a long-term, contract for steam or heat is necessary (CTED 2003). A stand-alone facility would be less efficient than the cogeneration plant. It would consume fossil fuels at a higher rate, and therefore, emit air pollutants and greenhouse gases at a higher rate.

3.1.3 Laydown Areas/Turnaround Space

The 11 acres of temporary laydown area would not be needed if the cogeneration plant were not built. However, the refinery would still require the permanent laydown areas for refinery maintenance and "turnarounds." The site shown in this document to provide that space with the least wetland and other environmental impact is the proposed site at the northeast corner of the refinery just west of Blaine Road and south of Grandview Road. Only the areas of permanent fill would be constructed, which would fill about 19 acres of wetlands. No other action would substitute for this requirement and have less wetland or overall environmental impact.

3.1.4 Summary Impact Evaluation

If the cogeneration project were not built, it would be possible to meet the need for a reliable steam supply by conventional boilers but at a higher cost and with greater environmental impacts. It would not be possible to significantly decrease the cost and improve the reliability of the electricity supply for the refinery. It would be possible to provide additional electricity to the region but at less efficiency and therefore greater fuel use and environmental impacts. . It would not be possible to provide the refinery maintenance turnaround area with less than about 19 acres of wetland impact. Therefore, the no-action alternative would not meet half of the components of the purpose and need, and more than half of the wetland impacts would still occur.

If the cogeneration project were not built, permanent impact by the cogeneration plant on about 12 acres of wetland and temporary impact by the laydown areas on about 5 acres of wetland would not occur. It is also reasonable to assume that any new power plant to be built in western Washington to supply the power demand will have some impacts on wetlands, since wetlands are so prevalent in this region. Therefore, the actual reduction in impact on wetlands by not building the cogeneration plant may be small. In other words, a no-build alternative is not likely to be without wetland impacts.

Other impacts associated with alternative steam and electricity sources would be higher than with the cogeneration plant. Without the cogeneration facility, the steam produced for the refinery would be produced with higher emissions of air pollutants per unit of steam. For example, the NOx emissions are more than 2 times higher for the most efficient stand-alone boiler that might be used and more than 16 times higher for some of the existing boilers than the cogeneration plant per unit of fuel. In addition, because the cogeneration plant is so much more efficient, the stand-alone boilers would use significantly more fuel than the cogeneration plant per unit of steam, thus increasing the effective difference in emissions.

Similarly, differences in air emissions and fuel consumption would exist between the cogeneration plant and any additional power plants that would provide the needed electricity. The cogeneration plant would be the most efficient source of power. Any likely alternative source (gas-fired plants) would necessarily have higher fuel consumption rates per unit of power and therefore, higher emissions of air pollutants and greenhouse gases. Air emissions are also likely to be higher because most power plants in the region are not subject to emissions limitations as stringent as those proposed for the Cogeneration Project.

The environmental impacts avoided by not building the cogeneration facility at the BP Cherry Point refinery may be more than offset by the environmental impacts of other actions required to fill the needs. In addition, the impacts of the cogeneration project are readily mitigated, while some alternative action impacts may be less easily mitigated.

3.1.5 Economic Considerations

The economic consequences of not building the cogeneration plant must also be considered.

The BP Cherry Point refinery is the only BP refinery in the United States without a cogeneration plant. Because refineries are large steam users, a cogeneration plant interconnected to a refinery is a good fit. With the cogeneration project, the refinery will receive less expensive reliable steam and power than without cogeneration, and the power produced for the regional market will be more cost-effective than other new sources of power. The reason for the refinery to pursue the construction of a cogeneration plant is the substantial annual savings in energy costs and reduced vulnerability to power market fluctuations. However, the economic benefits go much beyond the economics of the BP Cherry Point refinery. The economics of the whole region are linked to the reliable supply and price of electricity and fuel. .

It is difficult to predict what effect future power market fluctuations might have on the refinery, but in 2000 and 2001, they put the viability of the refinery at significant risk. In response to sky-rocketing electricity prices, the refinery temporarily added 26 diesel generators during the most severe electric power prices, and then replaced the diesel generators with 14 natural gas-fired generators until the power market stabilized. If electricity prices had stayed high long enough, the refinery may not have continued to operate. Without the refinery operating, the regional supply of fuel would be severely constrained, and the economic consequences would be enormous.

Electricity can not be stored. Therefore, supply must precisely equal demand. As this balance becomes closer and the reserve generating capacity margin becomes smaller, power prices become very volatile and can increase rapidly. Power buyers must find sources to meet demand, and if the supply gets too tight, they must find power at any cost, or their customers would be without power. Because supply must meet demand, if it falls short it is not that customers get less power, rather they get none, which is the reason for blackouts. All customers, including residential, commercial and industrial customers find this inconvenient and potentially devastating. Having the cogeneration plant operating would help prevent such disasters in two ways. The power demand of the refinery would no longer be a drain on the regional power grid, thus effectively lowering the demand. The excess electricity produced by the cogeneration plant would also increase the supply available to meet the growing regional demand.

3.1.6 Conclusion

The alternative of not building the cogeneration project would not satisfy the purpose and need stated at the beginning of this document. While it might reduce the amount of wetland impact, that is not certain, because some less efficient power generation facilities would have to be built in the region, and many proposed projects have significant wetland impacts. The economic consequences of not building the cogeneration plant might be enough to shut down the refinery under certain circumstances, and that would have broad and severe regional economic consequences. Not building the cogeneration facility would also forego the economic and environmental benefits of more efficient electricity production in the region.

3.2 ALTERNATIVE COGENERATION SITES.

As explained above, alternative cogeneration plant sites must meet four criteria in order to be practicable: size, proximity to refinery, security, and accessibility. Alternate technologies are not applicable for comparing sites. While there is likely to be a difference in costs between sites, costs are less important than impacts or feasibility. The cogeneration plant will require a site that is at least 33 acres in size. As explained above, the cogeneration site must be located within a one-mile pipe distance of the refinery and may not be located across a highway from the refinery in order to be a feasible site. Therefore, potentially feasible sites would include sites within the refinery fence, i.e., between Grandview Road on the north, Jackson Road on the west, Aldergrove Road on the south, and Blaine Road on the east. Existing refinery facilities already occupy most of this land, and sites on the west of the refinery do not have adequate accessibility from the highway and to the cogeneration site and refinery. This leaves only the northeast corner of the refinery with enough open space to consider inside the security fence and the highways. In addition, sites adjacent, but outside the fence to the east could be secured and are potential sites. Since Brown Road is gated and controlled by BP, sites both north and south of Brown Road would meet the security criteria.

Four potential sites (Sites 1 through 4) meet the four criteria, including enough area available to fit the cogeneration project (Figure 1). BP owns all of the potential sites, and therefore all are potentially available for the project. Two additional sites (Sites 5 and 6) were discussed in the Alternatives Analysis prepared by Golder Associates for the EFSEC permit application. These sites do not fit all the selection criteria, but are addressed here for completeness.

3.2.1 Site 1 (Proposed Site)

Site 1 is the proposed site. It is located just south of Grandview Road and east of the refinery fence. This site is referred to as Site 3 in the Golder Alternatives Analysis.

Size & Wetland Impacts

The proposed site has at least 40 acres available. The site could be expanded south or east, but that would encroach on more wetlands. It cannot be expanded to the north because of the County requirement for a 300-foot buffer between the plant site and Grandview Road. The site location has been selected to minimize wetland impact area. With the proposed site layout occupying 33 acres, 12 acres of wetland would be filled.

Proximity to Refinery & Related Infrastructure

This site is directly adjacent to the refinery fence and would have minimal impacts from connecting to required infrastructure. One access road and a permitted corridor for a transmission line connection to the BPA transmission line to the east are immediately adjacent. An existing natural gas line with capacity is in the utility corridor adjacent to the west edge of the site, and a water supply pipe from the Whatcom PUD is also in the corridor but a few hundred feet south.

Security

Site 1 is immediately east of the refinery security fence, which can be readily expanded to include the site. In addition, the steam pipeline would not have to cross a public road and it would therefore be secure.

Accessibility

This site is directly accessible to the proposed laydown areas and all facilities and infrastructure. Access to the refinery and Blaine Road are about 250 feet away, and access to Grandview Road is similarly short.

3.2.2 Site 2

Site 2 is south of the proposed site. It is just north of Brown Road and east of the refinery fence and the proposed Brown Road Materials Storage Area. This site includes a large part of Site 1 in the Golder Alternatives Analysis.

Size & Wetland Impacts

Site 2 has at least 40 acres available. The site could be expanded north or east, but those areas are essentially all wetland. With a site layout of 33 acres, at least 31 acres would be wetland fill. This impact conclusion is based on a wetland delineation for the Brown Road Materials Storage Area (URS 2003) and on a delineation by Golder Associates (Golder 2003) which showed 2 acres of upland in patches outside the Brown Road Materials Storage Area. The remainder of Site 2 is wetland.

Proximity to Refinery & Related Infrastructure

The site is near to the refinery, and impacts of connecting to the infrastructure would be only slightly greater than the proposed site because of greater distances for some utilities.

Security

Site 2 is close enough to the east of the refinery security fence that the fence could be readily expanded to include the site. In addition, steam pipeline could be made secure because it would not have to cross a public road.

Accessibility

This site is directly accessible to potential laydown areas (as evaluated below) and all facilities and infrastructure. Highway access would be by way of Brown Road.

3.2.3 Site 3

Site 3 is just south of Brown Road (and Site 2) and adjacent to the east refinery fence. This site is included as part of Site 6 in the Golder Alternatives Analysis.

Size & Wetland Impacts

This site has at least 40 acres available. The site could be expanded to the south or east, but those are essentially all wetland areas. With a site layout occupying 33 acres, it would essentially all be wetland fill. This impact conclusion is based on a wetland delineation for the Brown Road Materials Storage Area (URS 2003) that found about 5.5 acres of upland in the 11 acres to be used for the Brown Road Materials Storage Area. Nearly all of the adjacent area to the south appears to be wetland, based on reconnaissance-level information by both Golder Associates and URS. Site 3 would be located mostly south of the Brown Road Materials Storage Area in an area that is almost all wetland.

Proximity to Refinery & Related Infrastructure

The site is adjacent to the refinery. The impacts of connecting to the infrastructure would be similar to the proposed site. The transmission line connection would have to go an additional 1,200 feet. The gas pipe would have to be extended a few hundred feet from the metering station. A water pipe is nearby in the utility corridor.

Security

Site 3 is immediately east of the refinery security fence, which can be readily expanded to include the site. In addition, steam pipeline could be made secure because it would not have to cross a public road.

Accessibility to Laydown Areas

This site is directly accessible to potential laydown areas (as evaluated below) and all facilities and infrastructure. Highway access would be by way of Brown Road.

3.2.4 Site 4

Site 4 is the northeast corner of the refinery south of Grandview Road and west of Blaine Road. This site is referred to as Site 5 in the Golder Alternatives Analysis.

Size & Wetland Impacts

Site 4 consists of Laydown areas 1, 2, and 3 associated with the proposed site and the existing contractor parking lot. Although the 32 acres available at this location might be large enough for the cogeneration facility if the configuration were altered, it would be impossible to maintain the buffer along Grandview Road that is required by Whatcom County Code. Approximately 20 acres of this site are wetlands. The site could not be expanded because it is constrained on all sides. On the west, it is constrained by the drainage course that conveys clean runoff to the north across Grandview Road, which has refinery facilities just to its west. On the north, the site is constrained by the refinery security fence and the adjacent Grandview Road. To the east, the site is constrained by Blaine Road (a refinery road here) and the adjacent utility corridor, which has natural gas pipelines, water pipelines, and electrical transmission lines and must be maintained as a utility corridor. To the south, the site is bounded by wetlands and existing refinery facilities and use areas.

Proximity to Refinery & Related Infrastructure

All of the infrastructure is nearby, and the impacts of connecting to it would be similar to the proposed site. However, as explained above, the refinery needs additional laydown/turnaround areas. If this area were used as the project site, an additional 33 acres would be needed for construction laydown and turnaround activities, and the impacts to wetlands would occur for these new refinery laydown/turnaround areas.

Security

Site 4 is within the refinery security fence. Piping would be secure because the steam pipeline would not have to cross a public road.

Accessibility to Laydown Areas

The laydown area would occupy the site proposed for the cogeneration facility. In other words, if the cogeneration unit occupies this site, that would require a direct switch with the area occupied by the laydown area. Accessibility would be the same as the proposed site.

3.2.5 Site 5

Site 5 is located within the refinery and is the area previously used for refinery turnarounds. Part of that area is where the Isomerization Unit for meeting clean gasoline requirement is being constructed. This site is referred to as Site 2 in the Golder Alternatives Analysis.

Size & Wetland Impacts

This site was much too small (less than 20 contiguous acres) to accommodate a cogeneration facility even before part of it was required for other purposes. It has been eliminated from further consideration on this basis alone. The site is bounded on three sides and part of a fourth side by refinery facilities and use areas, and the remainder of the fourth side is a wetland adjacent to the proposed laydown area.

Proximity to Refinery & Related Infrastructure

This site is actually too close to refinery operations because construction of a cogeneration facility in the midst of the refinery would interfere with refinery operations. Construction in the midst of the refinery would be more difficult and more expensive, and would result in costly interference with refinery operations.

Security

Site 5 is within the refinery security fence. Piping would be secure because the steam pipeline would not have to cross a public road.

Accessibility to Laydown Areas

The site is accessible to the proposed laydown area and to Grandview Road via Blaine Road.

3.2.6 Site 6

Site 6 is located north of Grandview Road. It consists of approximately 2 acres of mixed forest and shrub habitat surrounded by old fields that include emergent wetlands. This site is referred to as Site 4 in the Golder Alternatives Analysis.

Size & Wetland Impacts

33 acres could be available at this location. Wetlands occur here, but we have not determined how much wetland fill would be required because the site failed to satisfy other essential criteria. The south side of the site is bounded by Grandview Road. Expansion in the other directions would encroach into wetlands.

Proximity to Refinery & Related Infrastructure

This site is not adjacent to infrastructure or security. Extension of gas, water, and transmission lines to the site would entail other impacts, including wetland impacts. For these items, there is also a cost element, because the infrastructure would have to be extended further to this site than to other sites. The distance that steam pipes would have to cover to deliver steam to the refinery would be more than a mile, which is beyond the threshold of current technology. The extra costs to extend infrastructure were not calculated because the site failed the security criterion.

Security

Site 6 is not readily incorporated into the existing refinery security system, so an additional security system for the site itself would be required. Such a system would be more costly and less secure than a single secured area. In addition, the steam pipeline would not be secure because it would have to cross a public road. Because security is such an important item in refinery operation, this is a fatal flaw, and therefore, the site fails the security criterion. Existing technology will not solve the problem.

Accessibility to Laydown Areas

The only areas available for laydown that are not almost entirely wetlands are located across a state highway from this site. Construction would be logistically very difficult, disruptive to the surrounding community and much more expensive. Therefore, accessibility is not suitable for the construction activity.

3.2.7 Summary Comparison of Alternative Cogeneration Sites

The alternative sites are compared in Table 2 on the basis of the criteria necessary to be practicable and wetland impact. It is clear that the only sites that might have lower wetland impact than the proposed site are not practicable according to one or more of the criteria.

Table 2
Comparison of Alternative Cogeneration 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

3.3 ALTERNATIVE LAYDOWN SITES

Alternative laydown sites must meet three criteria in order to serve the purpose and need: size, accessibility, and security. Cost is anticipated to be similar enough not to be a discriminator in comparing sites. Technology is also not relevant in comparison of sites because no alternate technology is available that would be applicable or be different on one site versus another. The cogeneration project requires construction laydown and staging areas 33 acres in size with easy accessibility to the construction site. The permanent laydown area for refinery use must be 22 acres.

The same sites considered practicable for the cogeneration plant would also meet the key criteria for practicability for the laydown/turnaround area (see Figure 2).

3.3.1 Site A (Proposed Laydown/Turnaround Area)

As a means of minimizing wetland impact overall, the construction laydown for the cogeneration plant is proposed to use mostly areas that will ultimately be used for refinery maintenance and turnarounds. That way, only one set of wetlands will be filled, not two. The proposed site is Site 4 considered for the cogeneration project located at the northeast corner of the refinery, south of Grandview Road and west of Blaine Road. A separate temporary laydown area (Laydown Area 4) of about 4 _ acres is located between the cogeneration site and Grandview Road. Site A is referred to as Laydown Site One, Areas One and Two, in the Golder Alternatives Analysis.

Size & Wetland Impacts

Using this approach, about 5 acres of wetland will be impacted by fill for temporary construction laydown area for the cogeneration project only. Those five acres will then be restored as wetland along with six acres of upland and become part of a visual buffer along the south side of Grandview Road. The remaining area (22 acres) will be permanently filled to provide the construction laydown needs for the cogeneration project and then the turnaround areas for ongoing refinery refurbishment activities. An existing 3.2-acre contractor parking lot would be incorporated as part of the laydown/turnaround area, but it is already used during turnarounds.

Accessibility

This site is readily accessible from the cogeneration construction area, the refinery, the highway, and the needed infrastructure.

Security

This site is within the refinery fence and meets all security requirements.

3.3.2 Site B (Proposed Cogeneration Site)

The site where the cogeneration project is proposed would not be available for use as a laydown/turnaround area if it is occupied by the cogeneration project. Potentially the two could be swapped.

Size & Wetland Impacts

A site big enough for the cogeneration project is big enough for the laydown area. If the locations were swapped, then the same amount of wetland impacts would occur at both locations.

Accessibility

Although this site would be readily accessible from the cogeneration facility if the cogeneration and laydown swapped places, it would not provide adequate accessibility from the refinery and its infrastructure that will be needed for the permanent refinery laydown/turnaround area.

Security

This site is adjacent to the refinery security fence and could be made secure by extending the fence.

3.3.3 Site C (Alternate Cogeneration Site)

Site C is the same site designated as Cogeneration Site 2 above. It is just north of Brown Road and east of the refinery fence and the proposed Brown Road Materials Storage Area. This site includes a large part of Site 1 in the Golder Alternatives Analysis.

Size & Wetland Impact

Site C has at least 40 acres available. With a site layout of 33 acres, at least 31 acres would be wetland fill. This impact conclusion is based on a wetland delineation for the Brown Road Materials Storage Area (URS 2003) and on a delineation by Golder Associates (Golder 2003) which showed 2 acres of upland in patches outside the Brown Road Materials Storage Area. The remainder of Site C is wetland.

Accessibility

Site C is adjacent to the proposed cogeneration site and would provide adequate accessibility to the cogeneration construction. While it is near to the refinery fence, it is farther from the functions needed for ongoing refinery maintenance and the infrastructure required for some of those functions. Therefore, the criterion of accessibility for refinery maintenance is only partially satisfied.

Security

Site C is near enough to the refinery security fence that it could readily be included within the security fence.

3.3.4 Site D (Alternate Cogeneration Site)

Site D is the same as Alternate Cogeneration Site 3. Site D is just south of Brown Road (and Site C) and adjacent to the east refinery fence.

Size & Wetland Impact

Site D has at least 40 acres available. With a site layout of 33 acres, it would essentially all be wetland fill. This impact conclusion is based on a wetland delineation for the Brown Road Materials Storage Area (URS 2003) that found about 5.5 acres of upland in the 11 acres to be used for the Brown Road Materials Storage Area. Nearly all of the adjacent area to the south appears to be wetland, based on reconnaissance-level information by both Golder Associates and URS. Site D would be located mostly south of the Brown Road Materials Storage Area in an area that is almost all wetland.

Accessibility

Site D is separated from the proposed cogeneration site by about 1,400 feet. The site would be accessible so long as no intervening facilities interfere with transport of materials, but it would make cogeneration project construction more logistically difficult and more costly than utilizing the proposed site. Site D is also adjacent to the refinery fence, but it is farther from the functions needed for ongoing refinery maintenance and the infrastructure required for some of those functions. Utilizing this site for refinery maintenance and turnaround activities would be more difficult logistically, more time consuming and more costly as a result. Therefore, the criterion of accessibility for refinery maintenance is only partially satisfied.

Security

Site D is adjacent to the refinery security fence and could readily be included within it.

3.3.5 Site E (Alternate Cogeneration Site)

Site E is located south of Aldergrove Road and east of Jackson Road along the refinery pipeline corridor. This site is referred to as Laydown Site 2 in the Golder Alternatives Analysis.

Size & Wetland Impacts

This site has at least 33 acres available. It is constrained on the west by Jackson Road, on the north by Aldergrove Road, and on the south by another public road. To the east is land not owned by BP, which is forested and probably contains wetlands. Part of the area was previously filled and is not wetlands, but an unknown amount of wetland would have to be included.

Accessibility

Site E fails the accessibility criterion for both cogeneration project construction and refinery maintenance and turnaround activities. It is located nearly two miles from the proposed cogeneration site. Assembling equipment at such a distance from the project site is logistically difficult and costly. Very large equipment would have to be transported on public roads, which would require modifications of the roads and interruption of traffic. The site is outside the refinery, across a public road, and at least a mile from key refinery infrastructure. It would not work for refinery maintenance activities.

Security

The site is outside the security fence and could not be incorporated within the refinery security perimeter. This site could not practicably be made secure for all the activities it would need to support. The key element for security is the security of the steam pipe extending across a public road. Technology does not solve the problems of making it both secure and functional.

3.3.6 Summary Comparison of Alternative Laydown Sites

The alternative sites are compared in Table 3 on the basis of the practicability criteria and wetland impact. It is clear that the only sites that might have lower wetland impact than the proposed site are not practicable according to one or more of the criteria.

Table 3
Comparison of Alternative Laydown Area Sites

Site	Size	Security	Accessibility	Wetland Impacts
A	Meets Criterion	Meets Criterion	Meets Criterion	19 acres
B	Meets Criterion	Meets Criterion	Meets Criterion for cogeneration, not for refinery use	12 acres
C	Meets Criterion	Meets Criterion	Meets Criterion for cogeneration, not for refinery use	31 acres
D	Meets Criterion	Meets Criterion	Meets Criterion for cogeneration, not for refinery use	33 acres
E	Meets Criterion	Fails Criterion	Fails Criterion	unknown

3.4 COMBINATIONS OF SITES

For the cogeneration project, all of the components of the project must be contiguous in order to function. It would not be practicable to put part of the components on one site and others on another site, since they are mostly integral components of the power plant.

However, for the laydown/turnaround area, it would be possible to have multiple sites as long as the size of each was large enough to accommodate the functions required and the other functional requirements are met. These sites would also have to be located in such a way as to efficiently manage the work and the work force.

For the cogeneration laydown areas, the smallest contiguous block now proposed is about 5 acres. This area would be used by one contractor to construct the electrical switchyard. All of the other activities will be controlled by the general contractor and must use a single entrance for security and site control. Some components of the project are large and require large contiguous areas to be available in order to maneuver several components simultaneously. Therefore, it is not feasible to further break the laydown area into smaller units located in different areas.

For the turnaround functions, the refinery area previously used provided over 25 acres of contiguous useable area. The many large components and simultaneous activities require such a large area, and it must provide unobstructed access to the refinery components. It might be possible to segregate a few functions into a separate area on a smaller parcel, but that would not diminish the requirement for a large contiguous block of area.

The only combination of sites that might offer some hope of reducing wetland impact might be a combination of the two sites north and south of Brown Road and adjacent to the cooling tower. In order to get 33 acres of laydown/turnaround area, more than 23 acres of wetland fill would be required.

No combination of sites would give the required laydown/turnaround area and require less wetland fill than the proposed site.

3.5 ALTERNATIVE CONFIGURATIONS

Alternative configurations for both the cogeneration site and the laydown/turnaround site were considered, and the practicable configuration with the least impact on wetlands was selected. The process is discussed below.

The first consideration was whether any of the alternate sites could accommodate either a reconfigured cogeneration layout or a reshaped laydown/turnaround area and result in less wetland impact than either the proposed cogeneration site or the proposed laydown/turnaround site. Since the wetlands in all the alternate sites are in large contiguous areas with small upland areas interspersed, there is no way to get the required area, meet the minimum requirements for access and security, and have less impact on wetlands. Therefore, alternative configurations of the two proposed sites were considered and none were found to be better than the proposed ones.

3.5.1 Cogeneration Site

The selection of the specific preferred site was made by moving the original site footprint around to incorporate as much upland as possible. That placed the site as close to the south side of Grandview road as allowed by the 300-foot setback from the road required by Whatcom County

Code. It also placed the site just east of the drainage ditch along the east boundary of the utility corridor that parallels Blaine Road.

The original footprint was generally rectangular, and the early design assumptions placed the detention basin mostly outside the rectangular plant footprint. Refinements in the design process and further efforts to minimize the facility footprint have allowed further reductions in wetland impact to be realized. As a result of these factors, the southeastern corner of the site (which is all wetland) is no longer proposed to be filled, which reduced the originally proposed wetland impact by 2.5 acres. The detention basin is now designed within the rectangular footprint. As a result, the area of wetland fill was reduced by about an acre. However, because the water that feeds that wetland will unavoidably be blocked by the constructed pad for the cogeneration plant, we have conservatively assumed the wetland will be lost.

3.5.2 Laydown/Turnaround Site

The original expectation of laydown area need was 41 acres. By taking advantage of existing access and keeping the laydown areas contiguous with the construction site, the area needed was reduced to 36 acres. The 3-acre existing contractor parking area was then incorporated as area that can be used at times other than turnarounds, reducing the total laydown area to 33 acres and further reducing the wetland fill needed for the laydown use. By temporarily using area that will become the buffer along Grandview Road, it was possible to make about six acres of that be upland and another five acres be temporary wetland impact.

The permanent turnaround area could not be further reconfigured to reduce wetland impact, since essentially all of the remaining area is wetland. However, choosing this site avoided the wetland impact that would likely occur if it were necessary to provide utilities and security to other locations.

4.0 CONCLUSION

This Alternatives Analysis has demonstrated that no other practicable action, site, combination of sites, or site configuration would have less wetland impact or environmental impact overall and at the same time meet the purpose and need. Therefore, the proposed sites for the cogeneration project and the laydown/turnaround area meet the required tests of Clean Water Act section 404 (b) (1) and section 230.10(a) Guidelines for Implementing the Clean Water Act.

5.0 REFERENCES

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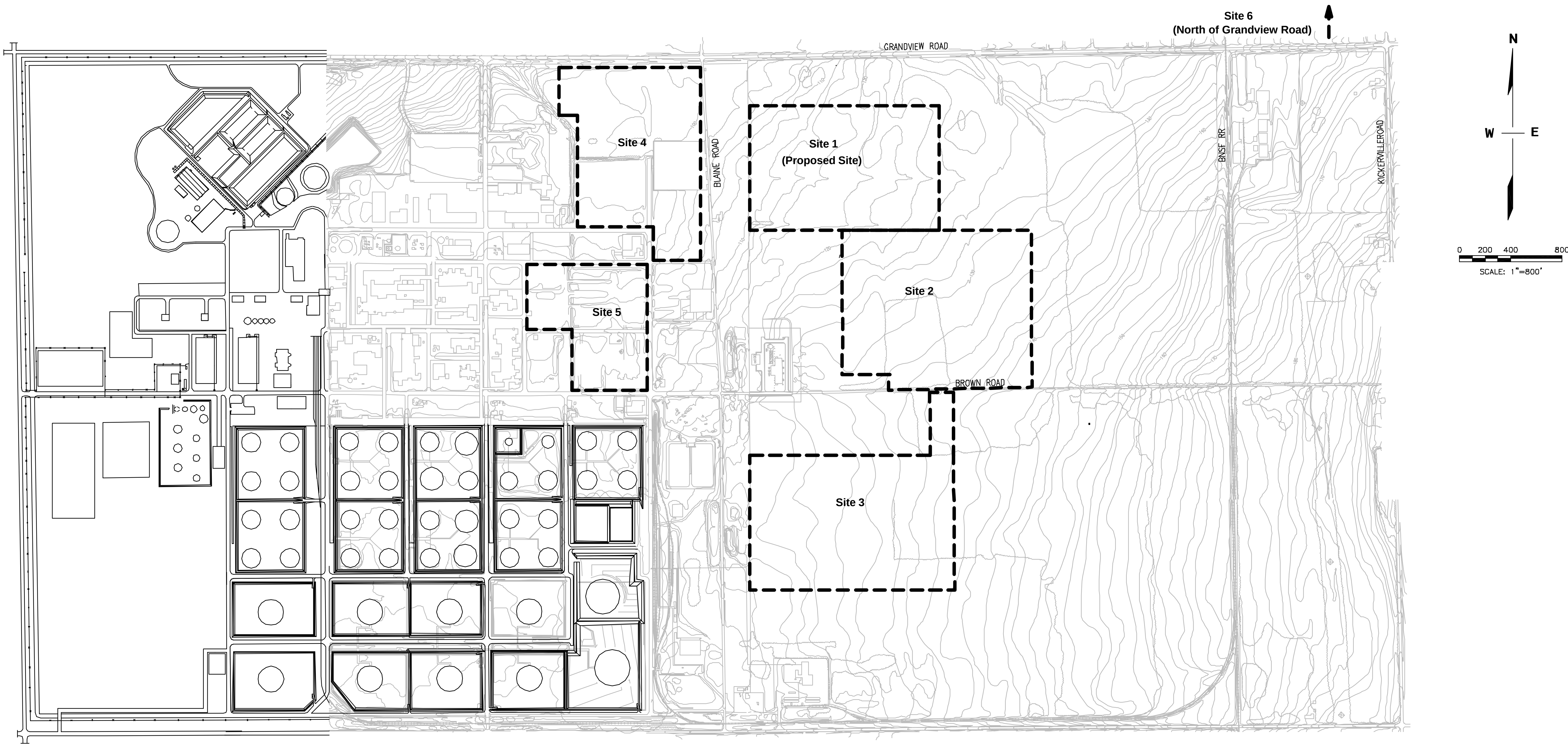

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Figure 1
BP Cherry Point
Alternative Cogeneration Plant Locations

URS

404 (B) (1) Alternatives Analysis
BP Cherry Point Cogeneration Project

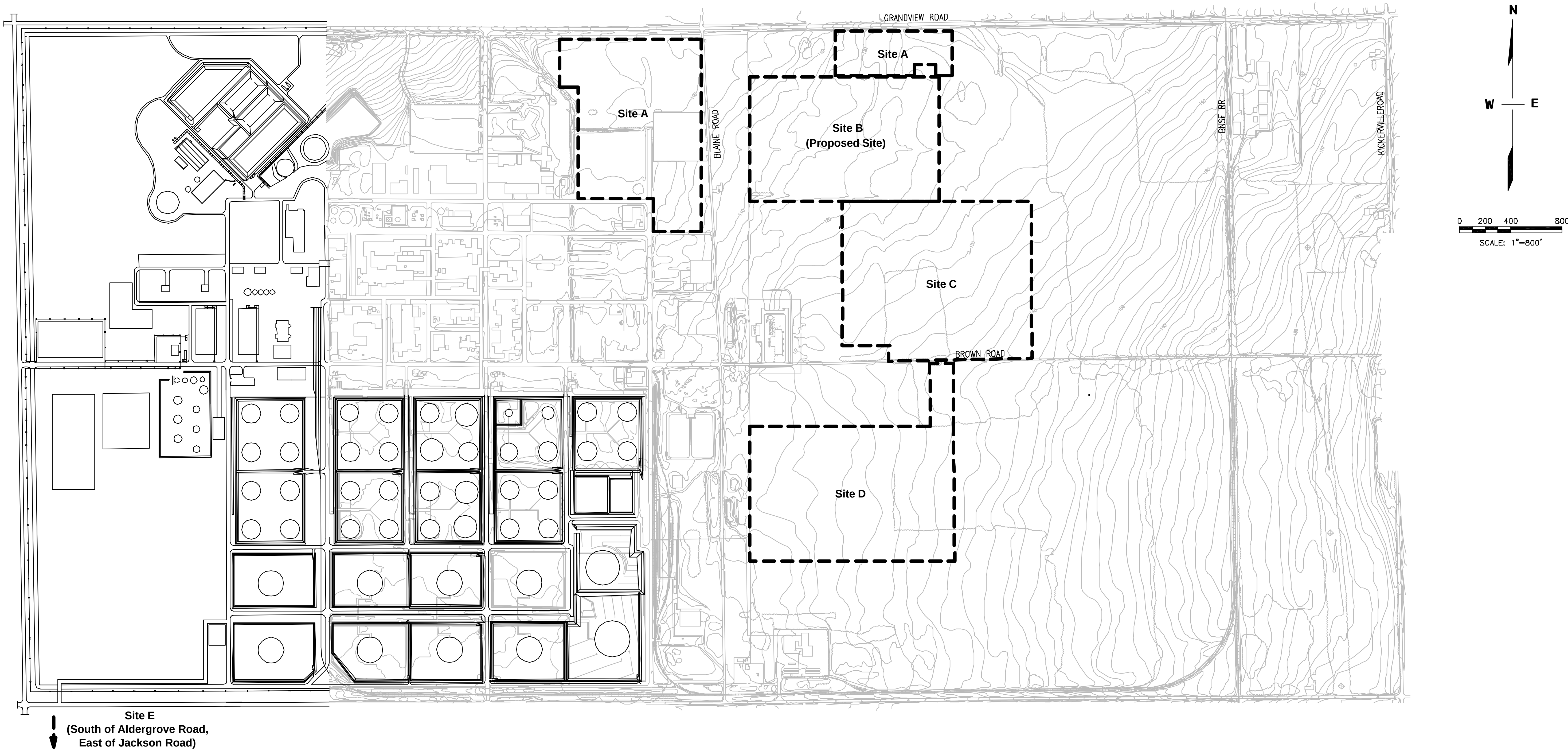

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Figure 2
BP Cherry Point
Alternative Laydown and Staging Locations

404 (B) (1) Alternatives Analysis
BP Cherry Point Cogeneration Project

APPENDIX B
AIR EMISSIONS MODELING ISOPLETHS

Number	Pollutant Modeled	Model Used and Assumptions[1]
Exhibit 22.1. Page 1	SO_2 Maximum Annual Concentrations	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 2	SO_2 Maximum 24-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 3	SO_2 Maximum 3-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 4	SO_2 Maximum One-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 5	PM_{10} Maximum Annual Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 6	PM_{10} Maximum 24-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 7	CO Maximum 8-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 8	CO Maximum One-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 9	NOx Maximum Annual Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 10	NOx Maximum 24-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.1, Page 11	NOx Maximum One-hour Concentration	ISC Prime, maximum potential emissions, no refinery reductions
Exhibit 22.2, Page 1	NOx Maximum Annual Concentration	ISC Prime, maximum potential emissions with refinery reductions
Exhibit 22.2, Page 2	PM_{10} Maximum Annual Concentration	Calpuff, max potential emissions, no refinery reductions
Exhibit 22.2, Page 3	PM_{10} Maximum Annual Concentration	Calpuff, max potential emissions, with refinery reductions
Exhibit 22.3	PM_{10} Expected Actual Maximum Annual Concentration	Calpuff, expected annual emissions, with refinery reductions and secondary particulate

1 All Calpuff modeling includes formation of secondary particulate; ISC Prime modeling includes secondary particulate by assuming 20%of sulfur emissions are converted to particulate matter.

FINAL COGENERATION PROJECT COMPENSATORY MITIGATION PLAN

BP Cherry Point

Prepared for
BP West Coast Products, LLC
BP Cherry Point Refinery
4519 Grandview Road
Blaine, WA 98230

June 2, 2004

URS

1400 Century Square
1501 4th Avenue
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33749546.05070

Final Cogeneration Project Compensatory Mitigation Plan, BP Cherry Point

ERRATA [Please make the following changes to your copy.]

Insert to Section 9.0 to follow paragraph 5:

The timing of maintenance/contingency measures will be based on the stage of plant growth when the measures will be most effective. The timing will be affected by weather patterns that affect the growing season and plant growth. If conditions and circumstances require maintenance/contingency activities to occur more than 5 days in 30 days between February 15 and July 31 (the WDFW-recommended period to protect against disturbing heron nesting and rearing activities), then Whatcom County Planning and Development Services will be notified and appropriate monitoring and protective measures will be agreed upon before the maintenance activity proceeds.

Insert to Section 10.0 in the first paragraph before the last sentence:

Earthwork is expected to be conducted during the dry months of late summer and early fall and therefore within the WDFW-recommended construction window for protection of heron nesting colonies (July 31 to February 15). Initial planting is also expected to be completed within this window. However, if conditions or circumstances require planting outside that window, then Whatcom County Planning and Development Services will be notified and appropriate monitoring and protective measures will be agreed upon before the planting proceeds.

TABLE OF CONTENTS

Page

TABLES

FIGURES

APPENDICES

EXECUTIVE SUMMARY

This Wetland Mitigation Plan was prepared to ensure appropriate mitigation for the wetland impacts associated with the proposed construction of the Cherry Point Cogeneration Project (Cogeneration Project), a 720-megawatt, gas-fired, combined cycle cogeneration facility (power plant), and the associated construction lay-down areas at the BP Cherry Point property. The BP Cherry Point property is located near Blaine, Washington, in unincorporated Whatcom County. Although the placement and design of the Cogeneration Project has avoided and minimized wetland impacts to the extent feasible, 4.86 acres of wetland will be temporarily disturbed and 30.51 acres of wetland will be permanently filled. The intent of the plan is to mitigate for these impacts by producing a net increase in wetland functional performance within the sub-basins that contain the proposed construction site.

The proposed construction will disturb low quality, historically degraded wetlands. Most of the area in the vicinity of the construction site is composed of broad fields drained by ditches and dominated by overgrown pasture grasses. Large portions of the wetlands are strongly dominated by non-native, invasive vegetation, primarily reed canarygrass (*Phalaris arundinacea*).

Wetland impacts associated with the proposed project will be mitigated via standard mitigation sequencing. Potential wetland impacts have been avoided and minimized by designing the location of construction areas away from delineated wetlands as much as possible given engineering constraints and the prevalence of wetlands in the area. A total of 9.27 acres containing both wetlands and wetland buffers (uplands) will be temporarily filled and subsequently restored. Another 1.81 acres of upland will be temporarily eliminated and subsequently forested after construction is complete to enhance a visual buffer between the plant site and Grandview Road. Any temporary or inadvertent impacts to wetlands that may occur during construction will be repaired and rehabilitated as appropriate.

Unavoidable impacts to wetlands will be compensated. The plan includes rehabilitating approximately 110 acres of degraded wetlands and surrounding uplands located within the BP Cherry Point property. These Compensatory Mitigation Areas (CMAs) will be rehabilitated by restoring historic drainage patterns via re-routing treated stormwater runoff and plugging existing ditches, removing and suppressing non-native, invasive plants such as reed canarygrass, and establishing native plant communities. Re-routing stormwater runoff will include installing pipes, culverts, and an inlet channel with diffuse-flow outlets to direct runoff from one of the two proposed detention ponds to one of the CMAs rather than let all of it go through a roadside ditch directly to Terrell Creek. All runoff from the other detention pond will be directed through an existing culvert to a series of ponds connected by natural channels and swales. The re-routed stormwater runoff will be directed to large natural areas that will provide additional hydrologic storage and water quality treatment. The forest and shrub habitats that will develop in the CMAs will further improve hydrologic storage through increased evapotranspiration and interception of precipitation. Thus, hydrologic impacts as well as other types of wetland impacts will be compensated.

The areas to be used for mitigation were selected as among the best available in the Terrell Creek basin. BP owns a large part of the basin, and BP's lands north of Grandview Road (about 1,000 acres) were assessed for mitigation potential. In all this area, the two proposed CMAs were judged to have the greatest potential for compensating wetland impacts associated with this project. The CMAs are located as near as possible to the proposed construction site, are positioned to receive re-routed stormwater runoff, and have great potential for improving ecological connectivity between the Terrell Creek corridor and natural areas to the south including the Lake Terrell State Wildlife Area. No other areas had more potential benefits. A survey of the properties for sale in the Terrell Creek basin revealed that only 5 parcels at least 20 acres in size are available. None of these parcels or combination of these parcels are able to provide the mitigation opportunities of the proposed mitigation areas.

1.0 PROJECT DESCRIPTION

1.1 PROJECT LOCATION

The BP Cherry Point property is located near Blaine, Washington in unincorporated Whatcom County. Whatcom County is bordered by Skagit County to the south, Georgia Strait to the west, and British Columbia, Canada to the north. The Cogeneration Project will be located east of the existing refinery within the BP Cherry Point property, south of Grandview Road and north of Brown Road.

The proposed construction area is approximately two miles east of Cherry Point and Georgia Strait in Sections 7 and 8 of Township 39, Range 1E. Minimization and restoration of wetland impacts will occur in this area. Compensatory mitigation will occur in the proposed Compensatory Mitigation Areas (CMAs), which will be located north of Grandview Road on the BP Cherry Point property in Sections 5 and 6 of Township 39, Range 1E. A site map showing the areas that will be impacted and the areas that will be restored and rehabilitated as compensatory mitigation is Figure 1.

A map showing the project site superimposed over a National Wetlands Inventory Map for the area is Figure 3 of the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a). A map showing the project site superimposed over a Soil Conservation Service (SCS) Soil Survey map is Figure 4 of the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a). These figures are also presented in Appendix A.

1.2 RESPONSIBLE PARTIES

BP West Coast Products, LLC (BP) is the project proponent and permit applicant. The contact person at BP for this project is Mike Torpey, who is the lead on Cogeneration Project permitting for BP. His phone number and address are as follows: 360/371-1757, BP Cherry Point Refinery, 4519 Grandview Road, Blaine, Washington 98230. The consulting firms responsible for the wetland delineation report entitled *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a) are Golder Associates, Inc. and Schott and Associates. URS Corporation is responsible for the Wetland Mitigation Plan and the delineation report of preexisting conditions on the compensatory mitigation areas.

1.3 DESCRIPTION OF OVERALL PROJECT

The proposed Cogeneration Project is the construction of a 720-megawatt, gas-fired cogeneration electric power plant and associated facilities including construction lay-down areas and access roads. Because the cogeneration facility will be an integral part of the refinery, it must be located in close proximity to the refinery facilities. The power plant will be configured with combined-cycle combustion turbines, each driving an electric generator. Electricity and steam produced by the cogeneration facility will power Refinery operations, greatly reducing the need for steam from existing refinery boilers. Excess electricity produced by the cogeneration facility will be provided to the Bonneville Power Administration (BPA) electrical grid. A Corps of Engineers (COE) permit for impacts on wetlands related to construction of a power line that will service the proposed power plant has been in place since 2000. The access roads and the area for the transmission tower pads have been constructed, but the towers and conductors have not been erected.

The cogeneration facility, including site access roads and a visual buffer area, will encompass 33.17 acres, of which approximately 25 acres will be converted to impervious surface area for the plant construction. Construction of the power plant and associated facilities (i.e. access roads) will permanently fill and/or cut off the hydrologic source for 11.91 acres of wetland (Table 1).

Approximately 33.1 acres of undeveloped land will be converted to construction lay-down areas. Lay-down areas are lots with graveled or impervious surface area that provide staging areas during construction and equipment storage area after construction. An existing gravel lot (Contractor's parking lot) that is 3.18 acres in size will be used for lay-down as well. The construction of the lay-down areas will fill a total of 23.46 acres of wetlands, of which 4.86 acres will be temporarily filled.

Two portions of the lay-down areas totaling 11.08 acres will be temporary and removed after construction is complete. 9.27 acres of these temporarily impacted areas are considered Restoration Areas since the 4.86 acres of wetlands and 4.41 acres of wetland buffers (uplands) that comprise these areas will be restored to native plant communities. The remaining 1.81 acres is within an upland area more than 300 feet from the nearest wetland to be restored. Upland forest will be established in this area to enhance visual buffer between the plant site and Grandview Road and provide ecological connectivity between the East Restoration Area and the forested areas east of the plant site. A map of existing wetlands, the proposed impact areas, the Restoration Areas, and the visual buffer areas is provided by Figure 2.

Thus, a total of 35.37 acres of wetlands will be filled. The total wetland area to be temporarily filled is 4.86 acres and the total wetland area to be permanently filled is 30.51 acres. Over 10,000 cubic yards of material will be removed from the construction site for this project.

Table 1
Expected Wetland Impacts

Project Area	Total Area (acres)	Area of Permanent Wetland Fill (acres)	Area of Temporary Wetland Fill (acres)
Cogeneration Facility[1]	33.17	11.91	0
Lay-Down Area 1	6.29	4.39	0
Lay-Down Area 2[2]	16.61	8.75[3]	4.66
Lay-Down Area 3	5.46	5.46	0
Lay-Down Area 4	4.74	0	0.20
Existing developed area (contractor's parking lot)	3.18	0	0
Total	**69.45**	**30.51**	**4.86**

[1] This area includes the power plant, Detention Pond 1, the two access roads, the northernmost 300 feet of the maintenance road, and the visual (forest) buffer area west of Lay-Down Area and north of the plant site.
[2] The area for Lay-Down Area 2 includes Detention Pond 2.
[3] The permanent wetland impact area includes the walking path that will traverse the West Restoration Area (see Section 4).

Within the construction zones, vegetation will be cleared, topsoil will be excavated, and the soil surface will be graded, compacted, and filled. The Cogeneration Project includes construction of power plant facilities, graveled or paved work areas and parking lots, paved access roads, and detention ponds.

The impervious surfaces to be created by the proposed project will reduce hydrologic storage and induce higher rates of runoff. This area is a relatively small portion (0.4%) of the total watershed area that comprises the Terrell Creek watershed, which is approximately 20.8 square miles in size. If left unmanaged, runoff from the site may degrade water quality and alter hydrologic regimes of downstream waterbodies (wetlands and Terrell Creek) and consequently degrade their habitat quality.

Two detention ponds will be constructed to control surface runoff from the proposed construction areas (Golder Associates 2002). Detention Pond 1 will collect runoff from the cogeneration facility and the portion of Lay-Down Area 4 to be restored after construction is complete. This area is labeled the East Restoration Area. Detention Pond 2 will collect runoff from the Lay-Down Areas 1, 2, and 3 including the portion of Lay-Down Area 2 to become the West Restoration Area (Figure 2). Oil/water separators will be installed at the inlet to each pond. The ponds have been designed to meet technical requirements of both Whatcom County and the Washington State Department of Ecology (Ecology) to provide adequate water quality treatment and flow control for runoff from impermeable surfaces to be created by the proposed construction.

Detention Pond 1 will be located in the northwest corner of the cogeneration site. Runoff from Detention Pond 1 will be piped northwest across Grandview Road and Blaine Road and dispersed across a large area within one of the CMAs. Detention Pond 2 will be located just west of Lay-Down Area 2. Runoff from Detention Pond 2 will discharge to an existing drainageway that extends across Grandview Road to an extensive pond and wetland system. Both areas to receive site runoff drain to Terrell Creek near its crossing under Jackson Road.

Thus, runoff from the project site will be directed to its historic drainage areas where it will support and enhance existing wetlands before draining to Terrell Creek. In addition, directing runoff to these wetland areas will improve runoff water quality and prevent increasing flow fluctuation in Terrell Creek above existing levels. A more detailed description of the post-mitigation hydrologic scenario is in Section 5.6.2.

Outside of the proposed construction area, existing ditches will be re-routed to avoid the plant site and support areas. Surface water in these ditches will continue to flow north under Grandview Road through the same ditches that currently support runoff from the undeveloped project site.

Impacts associated with the proposed project will be mitigated by applying the standard mitigation sequence. The placement and design of the Cogeneration Project has avoided and minimized wetland impacts to the extent practicable. The temporary portions of the lay-down areas will be restored to support native wetland and upland plant communities. Permanent impacts to the remaining 30.51 acres of wetlands to be filled will be compensated by rehabilitating approximately 110 acres of nearby lands mainly consisting of degraded wetland.

The proposed construction will disturb low quality, historically degraded wetlands. Although the wetlands within the proposed project site impart a variety of wetland functions, performance of these functions occurs at fairly low levels. The proposed restoration and compensatory mitigation will establish wetland and wetland buffer (upland) communities that perform these functions at moderate to high levels. In addition, proposed topographic and hydrologic modifications to the CMAs will restore historic drainage patterns.

1.4 WETLAND DELINEATION OF IMPACT SITE

See the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a) for the wetland delineation and maps.

2.0 ECOLOGICAL ASSESSMENT OF IMPACT SITE

This section summarizes ecological conditions of the proposed project site as determined in part by the findings of Golder Associates. Detailed descriptions of the environmental conditions of the proposed construction zones including the existing vegetation, soil, water regime, and wildlife of the on-site wetlands and uplands are found in the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a) and the *Technical Report on Wetland Functions and Values Assessment BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003b). These reports describe the geographic extent, functions, and ratings of the wetlands delineated in the vicinity of the proposed construction areas.

2.1 EXISTING VEGETATION

Most of the area within the proposed construction site and vicinity is composed of wide fields that are dominated by overgrown pasture grasses. These fields are fallow agricultural land that has not been cultivated in over 10 years. Interspersed with the fields are hedgerows and patches of semi-mature forest plantations that were planted for pulpwood harvest. Tree species comprising these plantation areas include Douglas fir (*Pseudotsuga menziesii*) and hybrid poplar (*Populus trichocarpa* x *deltoides*). Mature forest containing deciduous and coniferous trees that colonized the site naturally is located southeast of the proposed plant site. There are no existing structures within the proposed construction area.

A map showing delineated vegetation communities superimposed on an oblique aerial photograph of the construction areas, refinery, and areas to the west is Figure 5 of the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a). A map showing delineated vegetation communities superimposed on an overhead aerial photograph of the plant site and areas to the south and east is Figure 6 of the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a). These figures are presented below in Appendix A.

A large proportion of these fields are composed of palustrine emergent (PEM) wetlands as defined by the classification system of Cowardin et al. (1979). The PEM wetlands primarily consist of non-native pasture grasses such as red top (*Agrostis stolonifera*), colonial bent grass (*Agrostis capillaris*), velvet grass (*Holcus lanatus*), and reed canarygrass (*Phalaris arundinacea*). Large amounts of soft rush (*Juncus effusus*), a graminoid, also occur in these wetlands. The vegetation within the PEM wetlands has not been mowed or grazed in over 10 years.

One 0.6-acre palustrine scrub-shrub (PSS) wetland area containing immature hybrid poplar trees and one 1.69 palustrine forest (PFO) wetland that supports semi-mature (at least 12 years old and over 20 feet tall) hybrid poplar also occur within the construction zones.

Upland areas within the project site are primarily dominated by Himalayan blackberry (*Rubus discolor*), but contain some evergreen blackberry (*Rubus laciniatus*) as well. Some Douglas fir saplings planted in these areas are also present in some upland patches. Uplands also include some portions of the abandoned meadow area as well; these areas are dominated by colonial bentgrass and contain some stinging nettle (*Urtica dioica*), birdsfoot trefoil (*Lotus corniculatus*), and Canada thistle (*Cirsium arvense*). Some upland areas contain species found in the adjacent wetland areas including colonial bentgrass, reed canarygrass, and red alder (*Alnus rubra*) saplings.

The area encompassing the BP Cherry Point property originally supported forest with coniferous evergreen and broad-leaf deciduous trees, but was logged at least 100 years ago. The land was then cultivated for the first half of the 20th century and used as pasture and cropland. The predominant agricultural use of these areas was cattle grazing, which fostered the spread of non-native pasture grasses.

2.2 EXISTING WATER REGIME

The primary sources of surface water and soil moisture to the construction site are precipitation and lateral drainage from adjacent areas. Vertical drainage through the soil is limited by the underlying clay till, especially where it is within two feet of the soil surface. Lateral drainage is limited by low relief. As a result, soil saturation above 18 inches is widespread through the wet season in both wetland and upland areas. However, most areas of the project site typically dry out substantially in the latter half of the growing season.

The drainage ditches that are present throughout the site were originally installed to facilitate drainage and expedite drying of the soil for farming. These ditches continue to function although they are not maintained and are overgrown with vegetation.

2.3 EXISTING SOILS

Most of the soil in the area was derived from glaciomarine drift plains and is underlain by clay till starting at 10 to 30 inches below ground surface (bgs). Soil in the project site ranges from loam to silty clay loam, though some sandy soils and gravel not reflective of native conditions are present in some of the upland areas. The finer textured soils are mainly restricted to the wetlands. A map showing soil sampling locations is Figure 7B of the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a). This figure is presented below in Appendix A.

The two soil series mapped as occurring within the construction site including the Restoration Areas are Whitehorn silt loam, a hydric soil, and Birchbay silt loam, a nonhydric soil. As expected, the soils characteristic of Whitehorn silt loam are typically found in wetland areas whereas the soils characteristic of Birchbay silt loam are found in the upland areas.

Whitehorn silt loam is a very deep soil considered by Goldin (1992) to be poorly drained. However, a wetland delineation conducted by ENSR Consulting and Engineering (1992) that included intensive investigation of soils and hydrologic regime within the proposed site for the Cogeneration Project found high permeability and rapid lateral drainage within subsoil layers of soils characteristic of Whitehorn silt loam. As a result, the study concluded that the Whitehorn silt loam within this area should be considered somewhat poorly drained rather than poorly drained (Golder Associates 2003a). This soil is moderately fertile, has a moderate amount of organic matter, and is slightly acidic in the surface layer. The soil series contains inclusions of non-hydric soils. The water table in this soil fluctuates between 1 foot above ground and 1 foot below ground from November to May.

In contrast, Birchbay silt loam is a very deep, moderately well drained soil. The surface layer of the Birchbay silt loam is moderately fertile, has a moderate amount of organic matter, and is slightly acidic. This soil series has better natural drainage than the other soil types in the study area and is not listed as a hydric soil. The water table in this soil typically varies between 2 and 4 feet depth from December through April.

Topographic relief is minimal, but the area generally slopes to the north and northwest. Topography in the area is rolling to flat as determined by recent geologic history. Historic cultivation for crops and hay disturbed soil structure and smoothed what was likely rough micro-topography dominated by small hummocks

2.4 EXISTING FAUNA

The broad fields provide habitat for the abundant field mice, voles, and various small rodents. The forested patches located nearby provide habitat for wildlife species commonly found in woodland edge habitat in western Washington. These species include coyote, black-tailed deer, and numerous resident and migratory birds such as red-tailed hawk, American robin, song sparrow, and common yellowthroat. No amphibians, reptiles, or fish are known to inhabit the construction site.

A great blue heron (*Ardea herodias*) breeding colony is located approximately one mile west of CMA 2 and over one mile west of CMA 1 (Figure 1). This colony of between 200 and 400 breeding pairs (fluctuates over time) represents one of 4 large colonies located in northwestern Washington and southwestern British Columbia. Individuals from this colony are known to use nearby open field habitats similar to those present on CMA 1 and CMA 2. These nearby fields are used for staging during the nesting season and for foraging for amphibians and small mammals throughout the year.

Colony nesting bird species, including great blue herons, are considered a priority species in the state of Washington (WDFW 2000). Whatcom County lists herons as a species of local importance in its Critical Areas Code, Appendix C (Whatcom County). In connection with a different project, BP completed a *Heron Habitat Management Plan* in spring 2004 addressing the impacts of current and future construction on their lands north of Grandview Road (URS 2004). As part of this plan, a 1-year monitoring program began in March 2004 by a local biologist familiar with the local heron population. This monitoring seeks to specify high heron use areas on BP's property and what heron activities are occurring in those locations. This program will help BP adjust the implementation strategy for this mitigation plan on CMA 1 and 2. A more detailed discussion of issues concerning the heron colony is provided in Appendix F: *BP Cherry Point Cogeneration Facility Wetland Mitigation and the Birch Bay Great Blue Heron Colony*.

2.5 FUNCTIONS AND VALUES

The wetlands within the proposed project site serve a variety of hydrologic functions such as improving water quality, reducing peak flow, and decreasing downstream erosion. They also provide habitat suitability functions for wildlife, mainly mammals and birds. A more detailed discussion of the current functional performance of the wetlands within the construction site is in the *Technical Report on Wetland Functions and Values Assessment BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003b).

2.6 WATER QUALITY

Although no water quality monitoring has occurred on the site, the quality of surface water there is likely high. As stated earlier, the main source of moisture to the construction site is precipitation and drainage from adjacent areas. Since precipitation water quality is good and the adjacent areas that provide drainage are undeveloped and well vegetated, no water quality problems are expected to be present.

2.7 BUFFERS

Undeveloped upland areas that serve as wetland buffer areas are scattered across the project site. These upland areas support various plant communities including abandoned meadow, regularly maintained grassland, Douglas fir/Himalayan blackberry patches, Himalayan blackberry patches without Douglas fir, semi-mature hybrid poplar forest patches, and native mixed coniferous/deciduous forest. Upland portions of the abandoned meadow are found throughout the project site. The plantation and forested areas are mainly situated north and east of the proposed power plant and west of the northern portion of Lay-Down Area 2. Grandview Road limits the buffer area north of the project site to the right-of-way (ROW) immediately south of the road. Figure 6 of the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a), which is provided in Appendix A of this plan, shows the distribution of these plant communities within and immediately adjacent to the cogeneration facility site.

The area east of the plant site consists of hybrid poplar forest plantation and a small amount of mature forest dominated by both deciduous broad-leaved and coniferous needle-leaved trees. This area is over 2,000 feet wide (east-west). The area immediately south and southeast of the cogeneration facility site is comprised of the portion of Wetland D that will not be impacted by the proposed construction. Wetland D is a seasonally saturated/inundated palustrine emergent (PEM) wetland dominated by non-native pasture grasses and other herbaceous species. This wetland appears to extend east off site into the meadow area south of the forest plantation. The area southeast of Wetland D is a forested area that is mainly comprised of mature upland forest dominated by paper birch (*Betula papyrifera*), big-leaf maple (*Acer macrophyllum*), Douglas fir, and black cottonwood (*Populus balsamifera* ssp. *trichocarpa*). This area also contains Wetland E, a PFO wetland, and a mosaic of small, forested wetland patches. Blackberry (*Rubus* sp.) lines the edge of this forested area and dominates the narrow upland area south and southwest of Wetland D and north of Brown Road.

The area between Lay-Down Areas 1, 2, and 3 and the cogeneration facility where Wetland H is located is a regularly maintained field dominated by pasture grasses that serves as a utility corridor for the BP Cherry Point property (see Figure 2). The area west of the northern portion of Lay-Down Area 2 is a 500-foot wide patch of mature mixed coniferous/deciduous forest. This area is bordered to the west by the main entrance road for the BP Cherry Point Refinery.

2.8 WETLAND RATING

As determined by Golder Associates (2003a), each wetland within the construction zone is rated as a Category III wetland. See the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a) for copies of the original data sheets.

The ratings used for this project conform to the rating system described by the Washington State Wetlands Rating System – Western Washington (Ecology 1993). Wetlands with the Category III rating are the most frequently encountered and typically require a moderate level of protection. The Ecology rating system is designed to differentiate between wetland quality based on rarity, irreplaceability, sensitivity to disturbance, and functional performance. The wetlands found in the project area are not Category I or II wetlands since they do not provide habitat for sensitive or important wildlife or plants, are not regionally rare, and do not provide very high functional performance. No on-site wetlands are considered Category IV wetlands since all wetlands present are hydrologically connected to Terrell Creek.

2.9 POSITIONS AND FUNCTIONS OF THE WETLANDS IN THE LANDSCAPE

With the exception of Wetland I, the Hydrogeomorphic Classification of the wetlands within the project area is depressional outflow. These wetlands vary in size, but all are situated in topographical depressions that have closed contours on three sides and support surface water outflow to downstream waterbodies. Wetland I is considered a riverine flow-through wetland. Riverine flow-through wetlands are those that do not retain surface water significantly longer than the duration of a flood event.

These wetlands perform most hydrologic and habitat functions albeit at low performance levels as discussed in Section 4.4.4. The wetlands here have limited opportunities to perform some hydrologic functions since the areas within their upgradient catchment areas are undeveloped, well vegetated, and do not produce exceptionally large outflows of water. As mentioned earlier, the main sources of moisture to these wetlands is precipitation and shallow subsurface drainage from adjacent uplands. Although the site is located in the central part of the watershed, the on-site wetlands are situated in relatively small subcatchments and therefore have limited amounts of subsurface drainage provided to them.

The project site and adjacent areas to the east are part of a corridor of undeveloped land between the Lake Terrell Wildlife Area, a 1,500-acre reserve managed by the Washington Department of Fish and Wildlife (WDFW), and the Terrell Creek riparian forest. Although this corridor is fragmented by roads and both abandoned and active pasture, it may provide ecological connections between these areas for a wide variety of wildlife including large mammals such as blacktail deer and coyote. The proposed construction is not expected to severely degrade these connections since the on-site areas to the east will remain vegetated.

3.0 MITIGATION APPROACH

3.1 MITIGATION SEQUENCING

Although BP evaluated a number of project alternatives, it decided that the Cogeneration Project will best serve to provide reliable steam and electrical power to the BP Cherry Point Refinery and provide efficient and cost-effective electrical power to the region. The Cogeneration Project will also minimize the Refinery's reliance on outside sources for electricity and minimize impacts to the environment. For more information see *Siting and Wetland 404(b)1 Alternatives Analysis, BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003c).

BP also evaluated alternative sites for the Cogeneration Project based on the following criteria: sufficient acreage available, wetland impacts, proximity to the Refinery and related infrastructure, security and accessibility.

The proposed site avoids and minimizes wetland impacts as much as possible. Of the five possible alternative sites considered, only one that is large enough for the proposed project would impact less wetland area. However, that site was too far away from the refinery to be practicable for cogeneration and raised significant security concerns. Thus, the proposed site avoids and minimizes wetland impacts and meets the siting criteria best of all the sites considered.

The proposed plan is designed to mitigate wetland impacts by following the standard mitigation sequence as outlined in the Memorandum of Agreement between the Environmental Protection Agency (EPA) and the US Army Corps of Engineers (Corps). This sequence and a brief summary of how each mitigation component will be accomplished is provided below:

1. **Avoidance:** As discussed above, the site chosen for construction avoids wetland impacts. For a detailed account of how wetland impacts have been avoided by the proposed project, see *Siting and Wetland 404(b)1 Alternatives Analysis, BP Cherry Point Cogeneration Project [Revised}* (Golder Associates 2003c).

2. **Minimization:** Within the construction site, impacts to wetlands will be minimized by locating the construction areas away from delineated wetlands as much as possible given engineering constraints. The proposed construction will disturb low quality, historically degraded wetlands and avoid the high quality, forested wetlands located on the property. In addition, project-specific Stormwater Pollution Prevention Plans (SWPPPs) will be composed to provide guidelines for preventing the discharge of fill material in wetlands and streams during both construction and operation.

3. **Restoration:** Restoration of temporarily disturbed wetlands and wetland buffers will occur to re-establish wetland conditions and improve performance of most wetland functions. Any temporary

or inadvertent impacts to wetlands that may occur during construction will be repaired and rehabilitated as appropriate. Inadvertent impacts may include clearing and trampling of vegetation, soil compaction, discharge of fill, and alterations to hydrologic regime as a result of these activities. For a detailed account of how restoration of intentionally temporary impacts will be achieved, see Section 4 of this report.

4. **Compensation:** Unavoidable impacts to wetlands will be compensated by rehabilitating degraded wetland and upland areas within a portion of the BP Cherry Point property that will not be directly impacted by the proposed construction. For a detailed account of how compensatory mitigation will be achieved, see Section 5 of this report.

The plan for restoration and compensation incorporates recommendations from several resources including *Guidelines for Developing Freshwater Wetlands Mitigation Plans and Proposals* (*Guidelines*) (Hruby and Brower 1994), *Restoring Wetlands in Washington* (Stevens and Vanbianchi 1993), and *Washington State Wetland Mitigation Study – Phase 1: Compliance* (Ecology 2001). In addition, wetland and upland forest patches existing within the BP Cherry Point property were used in part as reference sites for the planting plans of restoration and compensatory mitigation.

3.2 GOALS

The goals of this mitigation plan are as follows:

1. Restore a total of 9.27 acres of wetlands and wetland buffers (uplands) to emergent, scrub-shrub, and forested habitats dominated by native vegetation within two Restoration Areas located in the northern portion of the construction site.

2. Rehabilitate approximately 110 acres of degraded wetlands and wetland buffers (uplands) within the two CMAs located on the BP Cherry Point property. Rehabilitation will occur by restoring historic drainage patterns via re-routing treated stormwater runoff and plugging existing ditches, removing and suppressing non-native, invasive plants such as reed canarygrass, and establishing emergent, scrub-shrub, and forested habitats dominated by native vegetation. Re-routing stormwater runoff will include installing pipes, culverts, and an inlet channel with diffuse-flow outlets to direct runoff from one of the two proposed detention ponds to a portion of the mitigation area rather than let it continue to go through a roadside ditch directly to Terrell Creek.

3.3 OBJECTIVES AND PERFORMANCE STANDARDS

This section describes the specific objectives and performance standards for the mitigation proposed for this project. A summary of these performance standards is provided in Appendix H.

3.3.1 Wetland Hydrology

Objective A: Re-establish wetland hydrology over 4.86 acres of the temporary lay-down areas (Restoration Areas) in the approximate locations of existing wetlands.

Performance Standard: Soils throughout the restored wetland areas within the Restoration Areas will be saturated to the surface for at least 10% of the growing season. The growing season extends from March 12 to October 31 and is 223 days long (Goldin 1992). Thus, the wetland hydrology criterion for the restored wetlands within the Restoration Areas is saturation at the soil surface for at least 22 consecutive days during the growing season. The presence of a free water surface within 12 inches of the soil surface over a continuous 22-day period during the growing season will be used to indicate wetland hydrology within the Restoration Areas. This performance standard meets the guidelines of wetland hydrology set by the Corps of Engineers Wetlands Delineation Manual (Corps 1987).

Objective B: Maintain wetland hydrology over the 79.7 acres of existing wetlands within the CMAs.

Performance Standard: As with the Restoration Areas, the wetland hydrology performance standard for the CMA's is saturation at the soil surface or inundation to a depth not exceeding 6 inches for at least 22 consecutive days period during the growing season. Measurement will be the presence of a free water surface within 12 inches of the soil surface over a continuous 22-day period during the growing season and will be part of the hydrologic monitoring program (Appendix G). This performance standard meets the guidelines of wetland hydrology set by the Corps of Engineers Wetlands Delineation Manual (Corps 1987).

3.3.2 Vegetation

Objective A: Maintain survival of planted trees and shrubs during the first five years before adequate vegetation cover can be measured.

Performance Standard: A survival/replacement standard will apply to trees and shrubs for the first five years after implementation, before cover is large enough to provide a reasonable method of measurement. One hundred percent survival is required for the first year and 80 percent for years 2 through 5 or until woody species cover reaches 30 percent in areas planted to tree and shrub communities.

Measurement: Measurement will be by a sampling method consisting of plots located along transects that span the width of each Restoration Area and each CMA. As recommended by Krebs (1999), at least 1% of the total area to be monitored will be sampled directly.

Objective B: Establish a variety of forested, scrub-shrub, and emergent plant communities dominated by native vegetation in both wetlands and buffer areas (uplands) within the Restoration Areas and the CMAs.

Performance Standard: The performance standards for cover of installed and volunteer woody (tree and shrub) and herbaceous vegetation outlined in Table 2 will be applied to all portions of the Restoration Areas and CMAs where tree and shrub communities will be planted. As explained in Section 4.6.5, some areas will remain free of installed trees and shrubs. Volunteer plants are those plants that establish on their own without direct planting or seeding. Herbaceous cover standards are much higher than the tree and shrub cover standards since herbaceous plants are expected to more rapidly colonize greater proportions of both the Restoration Areas and the CMAs.

Measurement: Measurement will be conducted by using a sampling method consisting of plots located along transects that span the width of each Restoration Area and each CMA. As recommended by Krebs (1999), at least 1% of the total area to be monitored will be sampled directly.

Table 2
Installed and Volunteer Plant Cover Standards

Criterion	Year 1	Year 2	Year 3	Year 5	Year 7	Year 10
Tree and shrub cover (%)	*	*	*	30	55	80
Herbaceous cover (%)	40	60	80	90	90	80

* = Tree and shrub survival, rather than cover, is measured during the first five years or until woody species cover reaches 30 percent in areas planted to tree and shrub communities.

Objective C: Reduce and suppress cover by non-native, invasive plant species.

Performance Standard: The performance standards for non-native, invasive vegetation outlined in Table 3 will be applied to all portions of the Restoration Areas and CMAs, including uplands and buffer areas. Those portions of the CMAs that currently have greater than 20% cover by reed canarygrass will have a performance standard of <20% through year 5. Portions of the CMAs that currently have less than 20% cover by reed canarygrass will have a performance standard of <10%. Since the Restoration Areas will have less than 20% cover by reed canarygrass immediately prior to initiating restoration activity, only the performance standard of <10% will be applied to these areas. By year 7, all areas are to have less than 10% cover of invasive species.

Measurement: Measurement will be conducted by using a sampling method consisting of plots located along transects that span the width of each Restoration Area and each CMA. As recommended by Krebs (1999), at least 1% of the total area to be monitored will be sampled directly.

The non-native, invasive plant species currently found in the CMAs include reed canarygrass, Himalayan blackberry, and evergreen blackberry. Of all these species, only reed canarygrass is listed by the Washington State Noxious Weed Control Board as a noxious species in Whatcom County. Reed canarygrass is a Class C weed, which indicates that is widespread and is targeted for control to serve educational or biological efforts only.

Table 3
Cover of Non-Native, Invasive Species

Species	Year 1	Year 2	Year 3	Year 5	Year 7	Year 10
Himalayan blackberry and evergreen blackberry (%)	<10	<10	<10	<10	<10	<10
Reed canarygrass cover in areas with >20% pre-existing cover (%)*	<20	<20	<20	<20	<10	<10
Reed canarygrass cover in areas with <20% pre-existing cover (%)*	<10	<10	<10	<10	<10	<10

* See Section 5.4.5, which discusses existing reed canarygrass cover distribution in the CMAs, and Figures 7A and 7B, which show existing reed canarygrass cover in the CMAs.

4.0 PROPOSED RESTORATION

4.1 SITE DESCRIPTION

Construction impacts associated with the Cogeneration Project that are intended to be temporary will occur in the northernmost 6.33 acres of Lay-Down Area 2 and all of Lay-Down Area 4. The western 2.94 acres of Lay-Down Area 4, which is 4.75 acres in total size, will be restored after construction is complete. This area will become the East Restoration Area. The remaining 1.81-acre portion of Lay-Down Area 4 contains no wetlands and will be planted as upland forest. The northernmost 273 feet (approximately) of Lay-Down Area 2, which is 6.33 acres in total size, will become the West Restoration Area. (Figures 1 and 2).

The total area of existing wetland within the East Restoration Area is 0.2 acres whereas the total area of existing wetland within the West Restoration Area is 4.66 acres. The wetland within Lay-Down Area 4 is a 0.2-acre portion of Wetland B-4, which is a PEMA wetland dominated by non-native pasture grasses. The wetland in Lay-Down Area 2 is called Wetland F and is also a PEMA wetland dominated by non-native pasture grasses. Detailed descriptions and maps of existing wetlands and plant communities at these sites are found in the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a).

4.2 OWNERSHIP

The Restoration Areas are within the BP Cherry Point property, which is owned by BP.

4.3 RATIONALE FOR CHOICE

The Restoration Areas were selected for the following attributes:

- The Restoration Areas are located within the portions of the proposed construction site that are only needed during construction of the Cogeneration Project. Because they will be located within temporary lay-down areas, the sites can be readily manipulated by heavy machinery to re-create wetlands and uplands in approximately their existing locations.

- The Restoration Areas are situated so that runoff can be directed to them from areas outside of the proposed construction site that will remain undeveloped. This runoff will be diverted to ensure that wetland hydrology will be established in the restored wetlands. The diversion will also be part of restoring flows to historic drainages.

- After removing compacted gravel installed for lay-down operations, native topsoil will be re-applied to the Restoration Areas. This topsoil currently supports trees, shrubs, and herbaceous vegetation and will be stored during project construction. Although the construction period will last 1.5 to 2 years, soil will be stored in a manner that minimizes reduction in soil fertility. Soil that currently supports reed canarygrass will not be applied to the Restoration Areas.

- The trees and shrubs that will establish in the Restoration Areas will provide a visual buffer between Grandview Road and the proposed facility site. The existing forest patches west of each Restoration Area and the Upland communities to be established in the Restoration Areas will provide buffer for the wetlands within the Restoration Areas as well as visual buffers for the plant site.

4.4 ECOLOGICAL ASSESSMENT OF THE RESTORATION AREAS

The Restoration Areas comprise portions of the area surveyed for the *Wetland Delineation Report BP Cherry Point Cogeneration Project [Revised]* (Golder Associates 2003a). Thus, much of the information contained in Section 2, which summarizes the ecological conditions of the proposed project site as determined by the Golder Associates (2003a) report, applies to the Restoration Areas as well.

The remainder of this Section deals with the topics listed in part 2.5.4 of the *Guidelines*:

4.4.1 Hydrology

Most of the West Restoration Area is wetland whereas most of the East Restoration Area is upland. The wetlands in the Restoration Areas are mainly palustrine emergent wetlands that are temporarily flooded (PEMA). Although this wetland type is identified as having temporary flooding, floods here are probably very rare. Instead, these ‘wet meadow’ communities retain saturation at or near the surface of the soil for long periods, extending into the beginning of the growing season, but typically dry out in the latter half of the growing season.

According to 30 years of data gathered at the WETS weather stations in Blaine and at the Bellingham International Airport, average annual temperature is 49.3 degrees Fahrenheit and average annual precipitation is approximately 36 inches (NRCS 1999). The wet season is herein defined as October 1 through May 31, the 8-month period in which over 82 % of yearly rainfall occurs according to the WETS table climate data from the Bellingham International Airport (NRCS 1999). The dry season (April 1 to September 30) should not be confused with the growing season, which is the period when soil temperatures 19.7 inches below the ground surface are greater than 41 degrees Fahrenheit (5 degrees Celsius) according to the 1987 Corps Wetlands Delineation Manual. The growing season length for the area is approximately

223 days as determined by averaging growing season length given by Goldin (1992) for Bellingham and Blaine. This period occurs from March 12 to October 31.

Soil moisture levels vary greatly between wet season and the dry season because the difference in precipitation between these periods is exacerbated by the poorly drained soils and their high rates of runoff. The low relief in the area and the clay till underlying most of the soils in this portion of Whatcom County greatly decreases vertical and lateral drainage, fostering widespread near-surface saturation and/or shallow inundation during the wet season. Soils in this portion of Whatcom County were formed in glaciomarine drift (Bellingham Drift) and are underlain by clay till starting at 10 to 30 inches bgs (Goldin 1992). Evapotranspiration and a minor amount of infiltration removes most of the moisture stored, causing relatively dry conditions in the latter half of the dry season.

Neither of the Restoration Areas is drained by ditches. However, subsurface drainage and overland flow from these areas reach the ditches that originate in undeveloped areas south of the proposed construction site. These ditches primarily carry surface water during the wet season and are dry during the dry season. A map of existing topography and drainage including ditches in these areas is in Figure 4.1-2 in the *BP Cherry Point Cogeneration Project – Application for Site Certification* (Golder Associates 2003d). This figure is presented below in Appendix A.

The portion of the ditch system outside the project area will be reconfigured during construction so that it will continue to convey surface water to areas where it currently flows. A map showing the ditch system plan during construction is in Figure 1A of the *BP Cherry Point Cogeneration Project Surface Water Management Design Basis* (Golder Associates 2002). An upgraded version of this figure that reflects minor changes in the construction plan is presented below in Appendix A.

After construction is complete and the temporary lay-down areas removed, ditch surface water will be diverted to supply seasonally inundated areas within the wetlands that will be restored. This diverted surface water will also ensure that the seasonally saturated portions of the restored wetlands possess wetland hydrology. Diverting minor amounts of flow to these areas will compensate for the loss of surface and ground water that is supplied by the areas to be eliminated by construction of the Cogeneration Project. A map showing the ditch system plan during operation is in Figure 1B in the *Design Basis BP Cherry Point Cogeneration Surface Water Management Design Basis* (Golder Associates 2002). An updated version of this figure that reflects minor changes in the construction plan is presented below in Appendix A.

4.4.2 Experience

URS has had experience with the design and construction of wetlands in projects located in Oregon, Washington, and Alaska. For example, URS managed the design and monitoring of two created mitigation wetlands using stormwater as the water source for the Boeing Company in western Washington. One project in included restoring a stream for trout habitat and creating a segment of new stream to link with the wetland. URS also designed a 4.58-acre compensatory mitigation site located within the BP Cherry Point property north of Grandview Road that involved removing non-native plants, creating a 0.5-acre seasonally inundated area, and establishing a mosaic of native plant communities (Corps Reference #98-4-02349).

4.4.3 Exotics (Non-native, Invasive Species)

For the purposes of this project, non-native species are considered to be species that were introduced to western Washington during white settlement. Of the non-native species in the area, only three non-native plants are considered to be invasive and therefore problematic to mitigation success. The three species are reed canarygrass, Himalayan blackberry, and evergreen blackberry. Since these species are likely to recolonize the mitigation areas (both the Restoration Areas and the CMAs) if not controlled, they will be the focus of the non-native, invasive species control program.

Of these species, reed canarygrass will likely be the most difficult to control. Reed canarygrass is extremely aggressive and often forms persistent monocultures in wetlands and riparian areas. This coarse-stemmed grass grows so vigorously that it is able to eliminate competing native wetland vegetation and prevent its reestablishment for indefinite lengths of time (Apfelbaum and Sams 1987; Lyons 2002). Reed canarygrass can form dense, persistent, monotypic stands in wetlands, moist meadows, and riparian areas. These stands exclude and displace native plants and animals and may be of little use to wildlife (Hoffman & Kearns 1997). In addition, reed canarygrass readily re-establishes itself upon clearing and can rapidly spread from intact stands. Reed canarygrass can be controlled using an aggressive, persistent approach.

The blackberry species present on site are known to aggressively invade upland areas and suppress establishment of native vegetation.

Control of non-native, invasive plant species in the mitigation areas will consist of a three-pronged approach: 1) initial removal, 2) subsequent maintenance for short-term control, and 3) establishment of native plant communities for long-term control.

Initial removal will occur through the removal of both the invasive vegetation and topsoil from the Restoration Areas prior to construction of the lay-down areas. Only topsoil currently supporting vegetation that does not include the above-mentioned non-native, invasive plants will be stored on site throughout the construction period.

Since the topsoil piles will be covered and stored for approximately 2 years, many of the seeds and rhizomes within the topsoil will die over the course of topsoil storage. Once the temporary lay-down areas are removed, the stored topsoil will be re-applied to the Restoration Areas. Non-native, invasive species that resprout will be sprayed with herbicide containing glyphosate plus surfactants. This or anic herbicide that contains active ingredients other than or in addition to glyphosate will only be applied to areas free from inundation and unlikely to support inundation within 2 weeks of the application. All herbicide will be applied by state-licensed applicators under a permit from the Washington State Department of Agriculture.

After native plants are installed and the seed mix applied, weed control will occur through a combination of mechanical removal and herbicide application. Mechanical control will include mowing and hand-pulling near installed plants to remove rhizomes as well as shoots. Weed control will occur with great care to prevent damage to native vegetation and will continue throughout the monitoring and maintenance period, as necessary.

As will be discussed in Section 8, URS will monitor success of non-native, invasive species control each year of a 10-year period subsequent to the initial planting and seeding. Monitoring results will guide recommendations given by URS to maintain cover by non-native, invasive plants below thresholds set by the performance standards. Areas with unacceptable levels of non-native, invasive plants will be marked in the field so that the maintenance crew can more accurately target their treatment practices. Although removal of non-native, invasive plants is expected to occur throughout the 10-year period, the intensity of the maintenance effort should decrease over time. Eventually, native vegetation will serve to suppress non-native plants over large portions of the site by shading and soil resource competition.

4.4.4 Wetland Functions

The proposed restoration has been designed to improve the performance of wetland functions. Wetland functions are defined as the biogeochemical, hydrological, and ecological processes and manifestations of these processes that occur within wetlands. Wetland functions tend to exert a relatively strong influence over the functional performance of the surrounding landscape. Functions are easily confused with values, which are more closely associated with the goods and services that wetlands provide to society.

The functional assessment method applied to wetlands on site is detailed in the *Methods for Assessing Wetland Functions* (Ecology 1999), which is based on the Hydrogeomorphic Approach for Assessing Wetland Functions (HGM Approach). The Corps of Engineers and other federal and state agencies are currently implementing the HGM approach to wetland functional assessment through the development of regional guidebooks. The possible range of index values for each function is 1 to 10, where 10 represents the highest level of performance. A total of 13 wetland functions were evaluated for each wetland area assessed. Since the on-site wetlands receive subsurface flow from adjacent uplands and are open basins with seasonal outflow, they are classified as depressional outflow wetlands.

The product of wetland functional performance index and wetland acreage was calculated for each function to determine acre-points. Although the wetland functional performance is influenced by wetland size, acre-points is a metric that essentially gives equal importance to wetland functional performance and wetland size. Acre-points (also called functional units) can be used to compare gain and loss of functional performance for each function, but should not be summed to account for each wetland's gain and loss of overall functional performance.

As mentioned earlier, the West Restoration Area is 6.33 acres in size and contains 4.72 acres of the 13.41 acres that comprise Wetland F. Since 0.06 acres of wetland within the West Restoration Area will be filled by a 5-foot wide walking path, only 4.66 acres of wetlands will be restored here.

Golder Associates (2003b) conducted the functional assessment method for Wetland F, under current conditions. Only part of the AU-1 portion of Wetland F will be temporarily affected by the lay-down construction. URS conducted another functional assessment for the portion of Wetland F that will be restored (West Restoration Area) as it will exist 25 years after compensatory mitigation is initiated (see Table 4). The completed data sheet for this assessment is presented in Appendix B. Although the northern 0.2 acres of Wetland B4 located within the East Restoration Area will also be restored, this area is considered too small to justify a full functional assessment.

Table 4
Comparison Between Wetland Functional Performance for Wetland F Under Current Conditions And 25 Years After Restoration Is Initiated in The West Restoration Area

Wetland Function	Functional Indices/ Acre-points Before Restoration Temporarily filled portion of Wetland F (4.66 ac)	Functional Indices/ Acre-points 25 Years After Restoration Restored Portion of Wetland F (4.66 ac)	Explanation
Potential for Removing Sediments	5/ 23.3	6/ 27.96	Slight increase (+4.66 acre-points) predicted due to increased constriction at the outlet.
Potential for Removing Nutrients	3/ 13.98	5/ 23.3	Slight increase (+9.32 acre-points) predicted due to increased areas that undergo fluctuation between aerobic and anaerobic conditions.
Potential for Removing Heavy Metals and Toxic Organics	5/ 23.3	4/ 18.64	Despite increased outlet constriction, slight decrease (-4.66 acre-points) predicted due to decreased cover by herbaceous vegetation.
Potential for Reducing Peak Flows	4/ 18.64	5/ 23.3	Slight increase (+4.66 acre-points) predicted due to increased outlet constriction.
Potential for Decreasing Downstream Erosion	5/ 23.3	8/ 37.28	Increase (+13.98 acre-points) predicted due to increased outlet constriction and increased cover by forest and scrub-shrub vegetation.
Potential for Recharging Groundwater	5/ 23.3	5/ 23.3	No change predicted since infiltration rate will not change.
General Habitat Suitability	2/ 9.32	4/ 18.64	Increase (+9.32 acre-points) predicted since there will be an increase in canopy closure, number of vegetation strata, number of snags, vegetation class interspersion, large woody debris, number of native plant species, and number of vegetation assemblages.
Habitat Suitability for Invertebrates	2/ 9.32	4/ 18.64	Increase (+9.32 acre-points) predicted due to increase in vegetation class interspersion, large woody debris, and maximum number of vegetation strata.
Habitat Suitability for Amphibians	2/ 9.32	2/ 9.32	No predicted despite installment of habitat features because the buffer condition and amount of seasonally inundated area will not change.
Habitat Suitability for Anadramous Fish	N/A	N/A	No anadromous fish can or will be able to access the site.
Habitat Suitability for Resident Fish	N/A	N/A	No resident fish can or will be able to access the site.
Habitat Suitability for Birds	3/ 13.98	4/ 18.64	Increase (+4.66 acre-points) predicted due to increase in number of snags, vegetation class interspersion, and invertebrate habitat suitability.

Table 4 (Continued)
Comparison Between Wetland Functional Performance for Wetland F Under Current Conditions and 25 Years After Restoration is Initiated in the West Restoration Area

Wetland Function	Functional Indices/ Acre-points Before Restoration	Functional Indices/ Acre-points 25 Years After Restoration	Explanation
	Temporarily filled portion of Wetland F (4.66 ac)	Restored Portion of Wetland F (4.66 ac)	
Habitat Suitability for Mammals	1/ 4.66	1/ 4.66	No change predicted due to proximity of plant site and associated facilities.
Native Plant Richness	1/ 4.66	4/ 18.64	Increase (+13.98 acre-points) predicted due to increase in maximum number of strata and number of native plant species, and decrease in area dominated by non-native plant species.
Potential for Primary Production and Organic Export	8/ 37.28	9/ 41.94	Increase (+4.66 acre-points) predicted due to increased rate of organic matter production.

According to the results of the functional assessment, the portion of Wetland F to be restored will slightly improve its currently low to moderate ability to remove sediment and nutrients from surface water inputs 25 years after restoration activity is initiated. The expected increases in the performance of the sediment and nutrient removal functions reflect the proposed hydrologic modifications, which will divert ditch flow from adjacent areas to seasonally inundated habitats and release these flows slowly through a constricted outlet (see Section 4.6). Conforming to the definition given by Ecology (1999), these seasonally inundated areas will possess inundation for greater than one month per year. As typical for most seasonally inundated wetlands in this region, on-site inundation will occur in the early part of the growing season. The opportunity for this wetland to perform these functions will remain low since these wetlands will only receive runoff from areas that will remain free from development or agriculture.

The potential for removing heavy metals and toxins will slightly decrease according to the model. The model interprets the decrease in herbaceous vegetation as a cause for a decrease in the wetland's ability to remove heavy metals and toxins. Since few of these contaminants enter the wetland currently and few are expected in the future, toxin and heavy metal removal is a function the wetland has and will have little opportunity to perform.

The wetland's current abilities to reduce peak flows and decrease downstream erosion will both improve as a result of the proposed restoration, which will direct a controlled amount of runoff to the restored wetland within the West Restoration Area. The shallowly inundated areas to be created will retain this runoff and thereby reduce peak flows and decrease the potential for downstream erosion. In addition, the increased cover by forest and scrub-shrub communities will further increase performance of these functions by fostering more evapotranspiration and improving the soil's ability to retain moisture and resist erosion. Given that surface water will be delivered to this wetland in greater quantity than had occurred previously, the opportunity for the wetland to perform peak flow reduction and downstream erosion reduction functions will be increased to a moderate level.

The potential for the wetland to recharge groundwater will remain low. The installment of compacted gravel padding atop the soil for the construction of the lay-down areas may temporarily diminish soil permeability. However, soil permeability will increase over time through the improvement of soil structure wrought by increases in tree and shrub root penetration and distribution. In spite of these improvements, infiltration rates to underlying aquifers will remain fairly slow at this site due to the relatively impermeable clay till found below the topsoil. The opportunity for this function to be performed may be slightly increased by the greater influx of surface water in the West Restoration Area after restoration is complete.

General habitat suitability will improve substantially due to the establishment of a variety of wetland habitats and native plants. Installation of the various vegetation classes and habitat features will provide greater opportunities for wildlife to forage, take cover, and breed. The mosaic of plant communities will also create more ‘edges’ (transition areas between plant communities), which will augment both wildlife and plant diversity.

Wildlife that will likely benefit from the proposed restoration are primarily invertebrates, birds, and amphibians. No threatened or endangered species are expected to benefit directly from the proposed restoration. The existing chain-link fence around the refinery including the proposed West Restoration Area and construction of chain-link fence around the proposed East Restoration Area will deter large mammals such as deer and coyote from accessing these sites. Given the deterring factors of the site and its surrounding area, the opportunity for the restored wetland to perform the habitat suitability functions will be low to moderate.

Since the wetlands currently do not provide fish habitat and will not provide fish habitat after mitigation activity is complete, the functional performance for Habitat Suitability for Anadromous Fish and Habitat Suitability for Resident Fish can not be evaluated. Although Golder Associates (2003b) did evaluate these functions for the wetlands in the construction site, they gave them very low scores (0 or 1).

The moderate to high amount of biomass produced by this wetland is currently exported at moderate rates to adjacent aquatic ecosystems via the ditch outlet. The proposed mitigation may cause more biomass to be produced on site through the establishment and growth of primarily deciduous, broad-leaved trees and shrubs. Organic material will continue to be released from the site at moderate rates through the meandering channel to be excavated on site.

In summary, the model predicts that the proposed restoration will incur improvements for nine functions, no change in three functions, and a slight decrease in one function.

In addition to the functional assessment, the Washington State Wetlands Rating System (Ecology 1993) was applied by URS to the portion of Wetland F that will be restored (West Restoration Area) as it will exist 25 years after restoration is initiated. Despite being less than 5 acres in size and nearly surrounded by roads and lay-down areas, this wetland area is predicted to support conditions suitable for rating as a Category II wetland. In particular, the wetland is predicted to retain three wetland community types that are moderately well interspersed, support relatively high plant diversity, have some beneficial habitat features, and maintain its hydrologic connection to Terrell Creek. The completed wetland ratings data form for the 4.66-acre wetland within the West Restoration Area under conditions predicted for 25 years following initial mitigation activity is presented in Appendix C. Although the northern 0.2 acres of Wetland B4 located within the East Restoration Area will also be restored, no future rating is given for this wetland since it is so small.

4.4.5 Buffers

The undeveloped areas outside of the proposed construction site that serve as buffers for the wetlands within the Restoration Areas will be maintained as wetland buffers.

Upland communities will be established in the portions of the Restoration Areas that were delineated as upland by Golder Associates (2003a). These uplands will also serve as buffers for the wetlands to be restored within the Restoration Areas. Excluding the gravel path, upland areas comprise 4.28 acres within the Restoration Areas. Uplands comprise 2.74 acres of the 2.94 acres in the East Restoration Area and 1.6 acres of the 6.33 acres in the West Restoration Area. The upland areas are mainly concentrated along the northern edge of these sites. The gravel path will cover 0.12 acres of the West Restoration Area. Upland communities will be established in the approximate locations of the areas that are currently upland. These areas will serve as buffers for the restored wetlands.

The eastern portion of Lay-Down Area 4 not included in the East Restoration Area will be reforested to serve as visual buffer for the plant site and provide a ecological connectivity between the East Restoration Area and the forested areas east of the project site.

4.4.6 Land Use

The uses of the Restoration Areas and the Cogeneration Project area will remain as planned for an indefinite length of time. The areas within BP Cherry Point property south of Grandview Road are zoned as 'heavy impact industrial'. However, current and expected future land uses in the area near the Restoration Areas are not likely to inhibit restoration of the Restoration Areas or degrade their functional performance over time. Air quality modeling indicates that emissions from the cogeneration facility will not significantly affect current ambient air quality in the area (Golder Associates 2003d). Water sources for the Restoration Areas will primarily be ditches re-routed so that they convey runoff from undeveloped areas on the BP Cherry Point property. The undeveloped land at BP Cherry Point includes hybrid poplar forest plantations, natural forest stands, abandoned pastures, and grasslands regularly maintained by mowing. Runoff from the Cogeneration Facility and associated lay-down areas will be directed away from the Restoration Areas.

Although land use in the vicinity of the project may change over time, no development that may occur here will likely degrade the Restoration Areas. Portions of forested plantations may be logged in the future to serve their intended purpose, but will likely be replanted. The portions of the plantations and natural forest stands that are not within the proposed construction areas and are within 200 feet south of Grandview Road will remain standing. These forested areas will serve as buffers between Grandview Road and the proposed facilities. Expansion of refinery or cogeneration operations may include erecting structures or lay-down areas in the fields located south of the proposed plant site. In addition, new utility lines may be added or existing utility lines maintained in the area between the plant site and Lay-Down Areas 1, 2, and 3 where Wetland H is located (Figure 2). However, no permanent structures that are not associated with the proposed project are likely to be erected within 100 feet of the wetlands within either Restoration Area. In addition, air quality modeling indicates that emissions from the cogeneration facility will not significantly affect current ambient air quality in the area (Golder Associates 2003d).

Current and future land uses outside the BP Cherry Point property are not likely to inhibit the proposed restoration or degrade functional performance of the restored wetlands over time. The nearest property to the Restoration Areas that is not owned by BP is located approximately 0.25 miles east of the East Restoration Area. Although it currently conveys light to moderate traffic, the portion of Grandview Road east of the intersection with Blaine Road (also known as State Route 548) is not likely to be expanded at any time (Lee pers. comm. 2003).

4.5 CONSTRAINTS

There are no known constraints outside the owner's control that might affect the Restoration Areas.

4.6 SITE PLAN

The temporarily impacted lay-down areas will be manipulated to create conditions that promote the establishment of native trees and shrubs. A variety of native wetland plant communities will be established in the approximate locations of existing wetland areas, and upland forest communities will be established in the approximate locations of areas that are currently upland.

4.6.1 Topography

Surface elevations that will foster upland conditions will be re-established in the approximate locations where uplands are currently found. Upland areas will be slightly elevated above wetlands and thus may be seasonally saturated below 12 inches beneath the soil surface. Wetlands will occur in the approximate locations where they are currently found, but their surface elevations will vary to include seasonally inundated areas as well as seasonally saturated areas. Site contours will be graded to allow a variety of hydrologic regimes within wetland areas that span from seasonally saturated 1 foot beneath the soil surface to seasonally inundated up to 1.5 feet above the soil surface. The proposed post-restoration contours for the Restoration Areas are shown in Figure 3.

Small mounds or 'hummocks' will be created throughout large portions of the Restoration Areas. Hummocks will be created by contouring imported topsoil that will be removed for power plant and lay-down area construction. Hummocks will have a slightly deeper effective rooting zone and will thus provide more moisture, nutrients, and rooting medium to vegetation per area of ground. Creating these hummocks will augment overall topographic variability on the site and facilitate the establishment of native trees and shrubs, which typically require deeper root penetration than herbaceous plants. The mounds will create a wider array of micro-environmental conditions that may provide greater opportunities for an increased diversity of plants and other organisms to utilize the site. Hummocks will not serve as berms for the seasonally inundated areas since berms typically require compaction, which is not conducive to plant growth.

Hummocks will be curving and oblong in shape have an average diameter of about 24 feet. The typical height above the surrounding elevation will be 1 foot, and no hummock will rise more than 1.5 feet in elevation. The hummocks will be spaced at approximately 60 feet on center (approximately 12 hummocks per acre). Hummocks will cover approximately 12.5% of the areas in which they are created.

Recontouring will occur by trackhoe and bulldozer during the dry season when soil moisture is at a seasonal low. Native vegetation will be installed during the following wet season.

4.6.2 Hydrologic Modifications

The Restoration Areas will be recontoured to create small seasonally inundated areas that will be vegetated with emergent herbaceous plants. As discussed in Section 4.6.2, surface water will be supplied to these seasonally inundated areas by diverting stormwater runoff from ditches that will be located adjacent to the Restoration Areas. See Appendix A for the upgraded version of Figure 1B of the *BP Cherry Point Cogeneration Project Surface Water Management Design Basis* (Golder Associates 2002) in Appendix A for the location of these ditches.

To ensure that appropriate flow levels will be diverted to the Restoration Areas, water levels will be controlled by adjustable weirs or similar devices. With these adjustable features, minor changes in channel flow may be made during the first 1 to 2 years after installation. If necessary, further adjustments with these features may be made as site conditions change.

The surface water diversion to the West Restoration Area will be directed through a 2-foot wide, meandering open channel excavated in the wetland portion of the West Restoration Area. The channel will direct water westward through the site and feed the two seasonally inundated areas to be created. The total size of the seasonally inundated area within the West Restoration Area will be at least 1.3 acre as measured by the ordinary high water mark. Maximum flow velocity through the channel will be less than 0.25 foot per second.

A 2-foot wide, open channel will also serve to convey surface water to and from the seasonally inundated area to be created in the East Restoration Area. Surface water will enter through a created channel to the seasonally inundated area when the water level is below the elevation of the weir to be installed at the diversion. When the water level exceeds the elevation of the weir, the seasonally inundated area will no longer accept water from the ditch, which will continue to support flow. This 'off-line' design minimizes intra-seasonal water level fluctuation within the seasonally inundated area and prevents flooding. The total size of this seasonally inundated area will be at least 0.06 acre as measured by the ordinary high water mark. Maximum flow velocity through the channel will be less than 0.25 foot per second.

4.6.3 Soil

As discussed earlier, native topsoil will be re-applied to the Restoration Areas after removing compacted gravel from the temporary lay-down areas. As discussed in Section 2.3, these soils are primarily loam and silt and extend 20 to 30 inches bgs before meeting the relatively impervious clay till layer. All soil placed in the Restoration Areas will be native, non-sandy soils taken from above the clay till layer.

The soil may be covered with mulch, erosion-control matting, and/or sterile annual grass seed to prevent soil erosion and sedimentation. These areas will then be replanted with native vegetation as soon as practicable. Tree and shrub planting will occur after site preparation work is complete. The planting, seeding, and mulch ring installment to occur on site are described further in Section 4.6.5.

A 5-foot wide walking path will be constructed across the West Restoration Area. The path will be comprised of gravel or wood chips and will traverse 0.06 acre of upland and 0.06 acre of wetland. The gravel path will be designed and constructed so that it will not be a barrier to surface or subsurface water flow.

4.6.4 Habitat Features

A number of habitat features will be distributed across the Restoration Areas. The habitat features planned for the site will provide structure to encourage habitat utilization by native wildlife species.

After recontouring is complete, at least 28 downed logs (3 per acre) will be placed across the Restoration Areas. Most of these logs will be derived from the hybrid poplars and Douglas firs that will be removed from the proposed construction areas. Most of these trees are 25 to 35 feet tall and have a diameter at breast height (dbh) that is 7 to 10 inches. Hybrid poplar logs will be left to dry for a few months before being placed in the mitigation areas to ensure that they do not sprout. A few other logs will be taken from the mixed deciduous/coniferous forest area on the BP Cherry Point property south of Grandview Road where an access road was recently constructed. These logs range in length from 35 to 90 feet and in diameter from 10 to 24 inches. The larger logs may have to cut into two or three pieces before transporting them to the mitigation areas.

Some logs will be stacked atop each other in a pyramidal shape (2 logs on bottom, 1 on top) to simulate woody debris of larger size. Other logs will be placed so that they extend into the seasonally inundated areas. The logs will act as habitat features, providing foraging opportunities and cover for insects, amphibians, small mammals, and birds (Stevens and Vanbianchi 1993).

A number of artificial snags, or dead-standing trees, will be erected on site. The logs to be used as artificial snags will be derived from the same source of woody material for the downed logs. Each snag will be at least 20 feet tall and at least one snag per Restoration Area will have a dbh greater than 12 inches. The base of each snag will be installed at least 4 feet bgs and stabilized with cement. A 10-foot long cross-beam may be attached to each snag to provide perches for red-tail hawks and other birds. The hawks and other predatory birds will prey on mice and voles, which might otherwise jeopardize the installed plants by gnawing and girdling.

At least two wildlife brush shelters will be constructed in each Restoration Area. These shelters will be placed away from areas that will be seasonally inundated. The base of each shelter will be composed of large, preferably rot-resistant boughs or logs that are 10 to 15 feet long and 4 to 6 inches in diameter. These pieces will be stacked criss-cross with parallel logs spaced approximately 2 feet from each other until the structure is 1 to 2 feet high. Branches of a gradually smaller diameter will be placed between and above the base logs in tee-pee style to form a more compact weave. Coniferous evergreen branches with needles still attached should be added to each pile to enhance shelter cover. The end product will be a sturdy, dome-like structure 4 to 6 feet high that has adequate space for small mammals to move about. Wildlife brush shelters provide heavy cover close to the ground, which can attract a variety of wildlife including rabbits, mice, voles, small birds, and amphibians (Monroe 2001; Connecticut Wildlife Division 1999).

In addition, plants like rushes and sedges will be placed in the shallow areas of each area expected to be seasonally inundated to provide ovideposition sites for native amphibians. These could be supplemented with branches or twigs with less than 8 mm (0.3 inch) diameter (Richter 1999) installed deep in pond substrate to prevent them from being dislodged by the rise and fall of water levels. The ovideposition sites provided by the branches will supplement those sites provided by the emergent vegetation that will become established in shallowly inundated areas.

4.6.5 Vegetation Establishment

The distribution of plant communities to be established in the Restoration Areas is shown in Figure 3. Plant schedules for these areas are shown in Tables 5 through 8. These schedules apply to the upland and wetland areas that will be restored. The schedules show the spacing, quantity, and condition of species to be installed in each community type. Included in these tables is the wetland indicator status (explained in the *Revised Cogeneration Project Compensatory Mitigation Areas Wetland Delineation Report* <URS 2003a>) for each plant species according to US Fish and Wildlife Service (1996).

The species chosen for each planting zone are deemed appropriate for the environmental conditions expected in the areas where they occur. The species composition, density (spacing), and other specifications of plant materials indicated in the plant schedules are based on findings from field investigations, best professional judgment, and recommendations from various resources.

Table 5 is the plant schedule for the Upland Forest communities, Table 6 is the plant schedule for the seasonally saturated (SS) wetland communities, and Table 7 is the plant schedule for the seasonally saturated (SI) wetland communities. Table 8 presents the specifications for the native seed mix that will be applied to all communities within the Restoration Areas.

Table 5
Planting Plan for Upland Communities

Scientific Name	Common Name/Wetland indicator status	Spacing	Condition & Size
Alnus rubra	Red alder/FAC	Intersperse the various tree species so that overall spacing on center = 12 ft	bare-root, 1.5’-3’
Betula papyrifera	Paper birch/FAC		bare-root, 1.5’-3’
Prunus emarginata	Bitter cherry/FACU		bare-root, 12-18”
Pseudotsuga menziesii	Douglas fir/FACU		bare-root, 1.5’-3’
Salix scouleriana	Scouler willow/FAC		rooted cutting, 1.5’-3’
Thuja plicata	Western red cedar/FAC		bare-root, 1.5’-3’
Tsuga heterophylla	Western hemlock/FACU-		bare-root, 1.5’-3’
Crataegus douglasii	Douglas hawthorn/FAC	Intersperse the various shrub species so that overall spacing on center = 8 ft	bare-root, 1.5’-3’
Holodiscus discolor	Oceanspray/NI		bare-root, 1.5’-3’
Oemleria cerasiformis	Indian plum/FACU		bare-root, 1.5’-3’
Rosa nutkana	Nootka rose/FAC-		bare-root, 1.5’-3’
Sambucus racemosa	Red elderberry/FACU		bare-root, 1.5’-3’
Symphoricarpos albus	Common snowberry/FACU		bare-root, 1.5’-3’

Table 6
Planting Plan for Seasonally Saturated (SS) Wetland Communities

Scientific Name	Common Name/Wetland indicator status	Spacing	Condition & Size
Alnus rubra	Red alder/FAC	Intersperse the various tree species so that overall spacing on center = 9 ft	bare-root, 1.5’-3’
Betula papyrifera	Paper birch/FAC		bare-root, 1.5’-3’
Picea sitchensis	Sitka spruce/FAC		bare-root, 1.5’-3’
Populus balsamifera ssp. *trichocarpa*	Black cottonwood/FAC		bare-root, 1.5’-3’
Salix lucida var. *lasiandra*	Pacific willow/FACW+		rooted cutting, 1.5’-3’
Salix scouleriana	Scouler willow/FAC		rooted cutting, 1.5’-3’
Thuja plicata	Western red cedar/FAC		bare-root, 1.5’-3’
Cornus sericea	Red-osier dogwood/FACW	Intersperse the various shrub species so that overall spacing on center = 6.5 ft	bare-root, 1.5’-3’
Crataegus douglasii	Douglas hawthorn/FAC		bare-root, 1.5’-3’
Malus fusca	Western crabapple/FACW		bare-root, 1.5’-3’
Physocarpus capitatus	Pacific ninebark/FACW-		bare-root, 1.5’-3’
Rosa nutkana	Nootka rose/FAC-		bare-root, 1.5’-3’
Rosa pisocarpa	Clustered wild rose/FAC		bare-root, 1.5’-3’
Rubus spectabilis	Salmonberry/FAC+		bare-root, 1.5’-3’
Salix piperi	Piper’s willow/FACW		rooted cutting, 1.5’-3’
Salix sitchensis	Sitka willow/FACW		rooted cutting, 1.5’-3’
Camassia quamash	Common camas/FACW	Install patches of herbaceous species where overall spacing on center = 1.5 ft over 1% of SS	plugs
Carex obnupta	Slough sedge/OBL		plugs
Deschampsia caespitosa	Tufted hairgrass/FACW		plugs
Eleocharis palustris	Creeping spike-rush/OBL		plugs
Juncus ensifolius	Daggerleaf rush/FACW		plugs

Table 7
Planting Plan for Seasonally Inundated (SI) Wetland Communities

Scientific Name	Common Name/Wetland indicator status	Spacing	Condition & Size
Fraxinus latifolia	Oregon ash/FACW	Intersperse the various tree species so that overall spacing on center = 14.5 ft	bare-root, 1.5'-3'
Salix lucida var. *lasiandra*	Pacific willow/FACW+		rooted cutting, 1.5'-3'
Populus balsamifera ssp. *trichocarpa*	Black cottonwood/FAC		bare-root, 1.5'-3'
Populus tremuloides	Quaking aspen/FAC+	Create small groves with 4.5 ft. on center over 2% of SI	bare-root, 1.5'-3'
Cornus sericea	Red-osier dogwood/FACW	Intersperse the various shrub species so that overall spacing on center = 6.5 ft	bare-root, 1.5'-3'
Lonicera involucrata	Black twinberry/FAC+		bare-root, 1.5'-3'
Physocarpus capitatus	Pacific ninebark/FACW-		bare-root, 1.5'-3'
Rosa pisocarpa	Clustered wild rose/FAC		bare-root, 1.5'-3'
Salix piperi	Piper's willow/FACW		bare-root, 1.5'-3'
Salix sitchensis	Sitka willow/FACW		bare-root, 1.5'-3'
Carex stipata	Sawbeak sedge/OBL	Install patches of herbaceous species where overall spacing on center = 1.5 ft over 1% of SS	plugs
Carex utriculata	Beaked sedge/OBL		plugs
Carex obnupta	Slough sedge/OBL		plugs
Eleocharis palustris	Creeping spike-rush/OBL		plugs
Juncus bolanderi	Bolander's rush/OBL		plugs
Scirpus americanus	American bulrush/OBL		plugs
Scirpus microcarpus	Small-fruited bulrush/OBL		plugs
Typha latifolia	Common cattail/OBL		plugs

Table 8
Native Seed Mix

Scientific Name	Common Name/Wetland Indicator Status	Estimated Quantity (% by weight)
Agrostis stolonifera	Creeping bentgrass/FACW	35%
Alopecurus aequalis	Short-awn foxtail/OBL	2.5%
Alopecurus geniculatus	Water foxtail/OBL	17.5%
Danthonia intermedia	Timber oatgrass/FACU+	2.5%
Festuca rubra	Red fescue/FAC	40%
Hordeum brachyantherum	Meadow barley/FACW-	2.5%

For Tables 5, 6, and 7, the average spacing is given for trees, shrubs, and herbaceous plants to be installed in each community. To improve habitat heterogeneity, planting densities will not be uniform throughout each zone. Instead, the zones will contain patches with a relatively high density, patches with moderate density, and patches with a relatively low density. The variety in density will allow planting in areas most suitable for their establishment and growth. The locations of the patches will be determined in the field.

Overall spacing for the Upland community is at a lower density than the SS or SI community types since there is far less reed canarygrass found in upland areas. Planting densities are set higher in the SS and SI communities to help suppress cover by reed canarygrass by increased competition and shading. Although their overall densities will be equal, the SI communities will have a higher ratio of shrubs to trees than the SS communities since native shrubs are better able to greater levels of hydrologic fluctuation.

No trees or shrubs will be planted in a few patches within the Upland and SI communities. In the Upland communities, these patches will be constricted to areas that have less than 20% reed canarygrass prior to initial mitigation activity. In the SI communities, these communities will be restricted to areas that are expected to have long periods of shallow (<1.5-foot) inundation.

Upland communities will be established in the portions of the Restoration Areas that were delineated as upland by Golder Associates (2003a). These communities may be saturated near or at the soil surface for a few months during the wet season. The overall tree and shrub spacing for the Upland communities will be approximately 985 plants per acre, which requires an overall spacing of 6.65 feet on-center.

SS communities will be established in wetland areas that will be seasonally saturated, but typically retain no saturation near the soil surface during the dry season. Some of these areas may retain shallow inundation for 1 to 3 months during the wet season. The overall tree and shrub density for the SS communities will be approximately 1,565 plants per acre, which requires an overall spacing of 5.3 feet on-center.

SI communities will be established in wetland areas that are seasonally inundated, but retain low levels of soil moisture during the latter half of the dry season. These areas will typically retain shallow inundation for greater than 3 months during the wet season and will likely remain saturated for a longer periods than the SS communities during the early part of the growing season. The overall tree and shrub density for the SI communities will be approximately 1,430 plants per acre, which requires an overall spacing of 5.5 feet on-center.

Herbaceous plants will be installed in various patches covering approximately 1% of the SS communities and 1% of the SI communities. The planting density for these patches will be approximately 1.5 feet on-center, which is roughly equal to 9,670 plants per acre.

Planting will be accomplished using a multi-phase approach. The initial phase will occur during the fall and/or spring before the Year 1 monitoring event. At this time, 50% of the woody (tree and shrub) and herbaceous plants will be installed. The remaining plants will be installed over the subsequent 3 to 4 years. If necessary, additional applications of the native seed mix may occur over the subsequent 3 to 4 years as well. This multi-phase approach allows more accurate assessment of on-site growing conditions, which is especially important in areas that will be seasonally inundated and/or where herbaceous vegetation will be planted.

The species in the seed mix are native grasses tolerant of a broad range of hydrologic regimes. The seed mix will be applied to the Restoration Areas in two phases. The first phase will occur in late summer or early fall a few weeks prior to installing any trees or shrubs. The second phase will occur the following spring after the first phase of tree and shrub planting is complete. At this time, the mix will only be applied to the interstitial space between mulch rings. Since interstitial spaces should comprise approximately 85% of the total area, the actual area upon which this seed mix will be applied is 7.9 acres. The total cumulative seeding rate will be 40 pounds per acre, which is a relatively high seeding rate for mitigation areas.

Nurseries specializing in wetland restoration will provide the plant stock. Trees and shrubs will be derived from local sources so that they are best adapted to the on-site conditions. All cuttings will be obtained from 1- to 2-year old wood, will be >3/8-inch in diameter, and will be >3 feet long. The quality and quantity of plants will also be verified by a URS biologist.

An installment contractor with experience in wetland rehabilitation will be responsible for plantings and seedings. Locations of each plant community zone will be staked in the field, and placement of plants will be verified by a URS biologist. All plants will be installed, and all seeds will be spread in spring or fall to enhance their chances of establishment and survival.

Each installed planting will receive a ring of imported mulch that will be at least 4 feet in diameter and 3 to 4 inches thick. However, mulch should be kept at least 1 inch away from the base of each plant to prevent pathogen and pest infestation. The mulch will be wood and bark-based with very few weed seeds. Mulch rings will help to suppress invasion by non-native plants, retain soil moisture, and contribute organic matter to the soil over time.

A minimum of water-soluble, slow-release, cold-weather tolerant fertilizer pellets will be applied to the soil pit where each tree and shrub is installed. Fertilizer pellets will be placed 3 to 4 inches below the ground surface adjacent to installed plant roots. In addition, a powder form of fertilizer will be applied to the ground surface at the base of each planting. This fertilizer will be a moderate- to rapid-release fertilizer to promote establishment and growth. Care will be taken to place the powder form of fertilizer only on the exposed soil at the base of the plant and not on the mulch where the high carbon:nitrogen ratio could cause much of the fertilizer to be rapidly depleted by micro-organisms.

Except for some cuttings, all installed plants will be protected from foraging mammals by plastic seedling protection tubes. In addition, plastic mesh exclusions may be constructed over patches of herbaceous plants to protect them from predation by geese, ducks, or mammals. These protections may be very important in preventing widespread mortality of newly installed plants.

4.6.6 Irrigation

An irrigation system will be constructed within the Restoration Areas after recontouring is complete. Water for irrigation will be derived from tapped water sources at the BP Cherry Point property. Irrigation will supply water during the latter half of the growing season to counter seasonal drought. Irrigation will likely enhance survivability of installed trees and shrubs, but may also encourage the growth of non-native, invasive plants such as reed canarygrass.

Irrigation water will be distributed by large ‘guns’ that have a spray diameter of 110 feet. The irrigation guns will be placed upon carts that travel automatically at slow, consistent speeds to ensure even distribution. Temporary paths less than 10-feet wide and spaced 200 feet apart will be made for the carts to travel across the Restoration Areas. Irrigation will continue through the second and possibly third growing seasons after planting is initiated. Irrigation equipment will be continually monitored and maintained by trained personnel. URS will be informed of irrigation equipment performance and will advise adjustments to the irrigation system as necessary.

The system will supplement rainfall to ensure that installed plants are provided with 0.5 inch of water per week from June or July through October, the driest portion of the year. Rainfall rates will be monitored on a weekly basis by checking data gathered by the weather station on the BP Cherry Point property.

5.0 PROPOSED COMPENSATORY MITIGATION

The proposed plan is designed to appropriately compensate for losses in wetland functional performance expected from the proposed construction. To compensate for the unavoidable and permanent removal of 30.51 acres of wetland, BP proposes to rehabilitate approximately 110.1 acres of wetland and wetland buffer degraded by historic agricultural practices.

5.1 SITE DESCRIPTION

The Compensatory Mitigation Areas (CMAs) are located on the BP Cherry Point property north of Grandview Road, just north of the site of the proposed Cogeneration Project (Figure 1). CMA1 is located east of Blaine Road, north of the proposed power plant site. It is situated in the southwest quarter of Section 5 of Township 39N, Range 1E. CMA1 is 50.3 acres in size. CMA2 is located west of Blaine Road in the southeast quarter of Section 6 of Township 39N, Range 1E. CMA2 is 59.8 acres in size. The geographic extent, location, and general character of the wetlands within CMA1 and CMA2 are described in the *Revised Compensatory Mitigation Areas Wetland Delineation Report* (URS 2003a). This report shows results of investigations that have occurred from 2001 to 2002.

The borders of each CMA are 25 feet from the outer edge of the ROW for Blaine Road and 50 feet from the northern edge of the ROW for Grandview Road. The ROW for Blaine Road extends 30 feet to the east and

30 feet to the west of the road's centerline. The ROW for Grandview Road extends 65 feet north and 20 to 25 feet south of the road's centerline. The ROWs contain telephone lines, power lines, and ditches. The areas between the ROWs and the CMAs are considered setback areas and will be reserved for possible utility installment.

5.2 OWNERSHIP

The CMAs are within the BP Cherry Point property, which is owned by BP.

5.3 RATIONALE FOR CHOICE

5.3.1 Mitigation Ratio

This plan proposes to enhance the CMAs to compensate for total wetland impacts at a ratio greater than 3:1 (see Table 9). Permanent impact to the PFO hybrid cottonwood plantation wetland will be compensated at a 4.5:1 ratio. Since this impact will consist of 1.69 acres of wetland, 7.61 acres will be enhanced as compensation. As requested by the Corps, the 4.86 acres of temporal impact from construction of the lay-down areas to be restored will be compensated at a 1:1 ratio. Enhancing 28.43 acres of wetland buffer (upland) will compensate for 3.55 acres of permanent wetland impact. The remaining 69.21 acres of degraded wetlands to be enhanced in the CMAs will compensate the remaining 24.99 acres of proposed wetland impact.

Although at least 1.2 acres of upland are expected to become wetland as a result of the proposed compensatory mitigation, wetland conversion will likely occur in small patches, the exact locations of which are difficult to predict. These factors would make monitoring to prove wetland conversion problematic. Therefore, BP has not claimed any credit for the wetland creation expected in CMA2.

Table 9
Summary of Compensatory Mitigation Acres, Ratios, and Credits

Type of Compensatory Mitigation	Size of Proposed Compensatory Mitigation Areas (acres)	Proposed Mitigation Ratio	Mitigation Credit (acres) [1]
Enhancement of existing degraded wetlands to compensate for temporary impacts to PEM wetlands	4.86	1:1	4.86
Enhancement of existing degraded wetlands to compensate for impacts to PFO wetland	7.61	4.5:1	1.69
Enhancement of wetland buffer areas (uplands)	28.43	8:1	3.55
Enhancement of existing degraded wetlands to compensate for permanent impacts to PEM wetlands	69.21	2.8:1	24.99
Total area	**110.11**	**3.1:1**	**35.37**

[1] Mitigation credit determined by dividing the acreage of each mitigation type by the proposed mitigation ratio.

The Corps normally recommends compensating for permanent wetland impacts at a minimum of 3:1 ratio for wetland enhancement. For temporary wetland impacts, the Corps recommends using a 1:1 ratio for wetland enhancement. Ecology guidance emphasizes that "the goal is always to replace the lost functions at a 1:1 ratio" (Ecology 1998). Ecology has established general mitigation ratios because it is usually necessary to increase the replacement acreage in order to accomplish the goal of replacing lost function. According to Ecology's ratios, impacts to Category II and Category III PEM wetlands can be compensated at a 4:1 ratio for enhancement whereas impacts to Category II and Category III PFO wetlands can be compensated at a 6:1 ratio for enhancement.

The proposed downward adjustment of Ecology's general mitigation ratios is appropriate in this situation for several reasons:

- The wetland areas to be eliminated have already been greatly disturbed by historical agricultural practices. The wetlands within the construction zones are rated as Category III wetlands under the Washington State Wetlands Rating System (Ecology 1993) and are providing only minimal performance of wetland functions. The loss of such wetlands will constitute only minimal environmental impact. Accordingly, their functional performance can be more than fully replaced with lower ratios than those outlined in Ecology's guidance.

- The wetland areas to be enhanced have also been greatly disturbed by historical agricultural practices though they are classified as Category II wetlands. These areas have high potential for improvement via rehabilitation. The proposed compensatory mitigation will significantly improve overall wetland functional performance on site and convert low quality Category II wetlands into a high quality Category II wetlands within 25 years. The completed wetland ratings data forms for the CMAs under conditions predicted for 25 years following initial mitigation activity are presented in Appendix C.

- URS has the extensive experience and technical knowledge of the BP Cherry Point property necessary to achieve successful wetland enhancement as proposed by this plan. URS designed and is currently monitoring enhancement of a 4.58-acre wetland area on the BP Cherry Point property that was initiated in fall 2000. This area was abandoned agricultural land strongly dominated by reed canarygrass. By reducing reed canarygrass cover, creating a shallow, seasonally inundated area, and establishing native plant communities, the goal of improving ecological integrity and overall functional performance is well on the way to being accomplished. This project is considered as a pilot project for the proposed compensatory mitigation. A copy of the *Year 2 Monitoring Report for Wetland Compensatory Mitigation, 4.58 acres BP Cherry Point Refinery* (URS 2002) is in Appendix D. An addendum displaying the additional photographs depicting site progress has been added to the monitoring report.

As recommended by the Federal Committee on Characterization of Wetlands for wetland enhancement and restoration projects, the proposed enhancement and restoration will improve wetland functional performance and benefit the functional performance of the surrounding landscape (Lewis, Jr. et al. 1995). Non-native, invasive plants (reed canarygrass, Himalayan blackberry, and evergreen blackberry) will be removed as much as possible. Stormwater runoff from the cogeneration facility's detention pond will be directed to a portion of one of the CMAs to improve water quality and restore historic drainage patterns. Stormwater from the detention pond to serve Lay-Down Areas 1, 2, and 3 will be directed to existing ponds and wetlands located west of the CMAs, also contributing to the restoration of historic drainage patterns. A mosaic of wetland habitats with diverse species composition and structure will be established in the CMAs. Habitat features such as downed logs and wildlife brush shelters will be placed in various locations to provide additional cover and forage for wildlife.

5.3.2 Site Selection

Off-Site Areas

A survey of the Terrell Creek basin was conducted to search for off-site properties that may be suitable for use in compensatory mitigation. Five vacant land properties equal to or greater than 20 acres in size and situated within the Terrell Creek watershed were for sale in 2002 (Figure 4). None of these properties were deemed to have high potential to compensate for the proposed wetland impacts. A combination of two or more of these properties used for compensatory mitigation would not satisfactorily compensate the proposed impacts either. Even in combination, the total area in these off-site parcels that could be used for compensatory mitigation is much lower than the total area to be used in the CMAs. Moreover, the logistics required for rehabilitating and maintaining one or more off-site mitigation areas would be problematic. A brief description of these five properties and their potential to provide area for compensatory mitigation is provided below:

1. The property closest to the project site is located on Brown Road, less than 0.5 mile east of the refinery. This parcel is 39.1 acres in size and is being sold by Re/Max Inc., Whatcom County. This property supports mature, second-growth forest over the western half and regularly maintained meadow (abandoned pasture) over the eastern half. The National Wetland Inventory (NWI) shows wetlands extending across the entire property. Approximately one-half the property contains a PFOA wetland community and the remaining half contains PEMA and PEMC wetland communities. A wetland delineation conducted in 1992 (Pegasus Earth Sensing Corporation 1992) found that most of the site consists of upland. However, the study found 11 wetlands totaling 9.3 acres in cumulative size. Wetlands were found in both the forest and the meadow. Since the property is far from a reliable source of water, creating wetlands on site would likely be difficult without a large amount of grading. The property is reportedly situated on a drainage divide and so only part of the property lies within the Terrell Creek basin. Thus, the potential for this property to be used as compensatory mitigation is low to moderate.

2. Another vacant-land property located within the Terrell Creek basin is located just south of Aldergrove Road, a few hundred feet west of North Star Road. This parcel is 21.5 acres in size and is currently for sale. Wetlands appear to be present on site. The NWI map shows this property to contain approximately 7.5 acres of PEMA wetlands. Review of aerial photographs and roadside observations indicated that a large portion of the site is meadow that is likely mowed for hay. The maintained meadow is over 15 acres in size and may extend across much of the PEMA wetland as indicated by the NWI map. Mature deciduous, broad-leaved forest extends east from the source of Terrell Creek across much of the property. A substantial portion of the on-site forest appears to be wetland. This portion of wetland is likely performing wetland functions at a relatively high level and could not be greatly improved. The property appears to have moderate potential for wetland enhancement and/or creation in the meadow areas.

3. This vacant-land property is located north of Grandview Road and east of Kickerville Road. The property is 20 acres in size and lies just north of Terrell Creek. The property is situated at the end of a gravel road and is relatively secluded. According to the NWI map, no wetlands occur in or near this property. Deciduous, broad-leaved forest covers much of the site. A utility corridor that is over 100 feet wide runs across the middle of the property. Trees and shrubs within the corridor appear to have been cleared and meadow vegetation that replaced the trees and shrubs appear to be well maintained. The northern portion of the site appears to be open forest with abundant brush and some gravel roads. A tributary of Terrell Creek runs through mature forest located along the southern edge of the property. The tributary joins Terrell Creek approximately 200 feet west of the property boundary. This parcel is almost entirely surrounded by forest and maintained meadows. The potential to enhance or create wetlands in this property appears low.

4. The fourth vacant-land property for sale that is located within the Terrell Creek basin is located on the corner of Blaine Road and Arnie Road. The NWI map shows that wetlands cover well over one-half the property. PEMA/PSSA wetland communities are shown to be located in the northern and southeastern portions of the site. A PFOA community is situated in the northeastern part of the parcel. This property is partially cleared, but contains mature deciduous, broad-leaved forest across much of the southern portion of the site and in the PFOA wetland community in the northeastern portion of the site. Overgrown meadow exists in the northwestern and central portions of the site. A few trees and shrubs are scattered across the meadow areas. The site has fairly level topography with no water features. This 40-acre property lies just east of a residential development. Properties to the north east, and south remain undeveloped or are under agricultural production. The potential to enhance or create wetlands in this property appears moderate.

5. This 21-acre property is located off of Holiday Road, just south of Birch Bay – Lynden Road. The NWI map shows that a PEMC wetland community covers approximately one half the property. This wetland area extends across much of the northern and eastern portions of the parcel where very few trees and shrubs are present. Large areas in the western and southern parts of the property support shrub-dominated habitats and semi-mature to mature deciduous, broad-leaved forest. The site has fairly level topography with no water features. The parcel is situated very just east and south of moderate density commercial and residential development. Properties to the south and east remain undeveloped or are under agricultural production. The potential to enhance or create wetlands in this property appears moderate.

<u>On-Site Areas</u>

In 2001, URS assessed over 1,000 acres (>400 hectares) of mostly agricultural land north of Grandview Road on the BP Cherry Point property for its potential to be used as compensatory mitigation (URS 2001; see Appendix E). An on-site investigation and remote resource information analysis were conducted to determine the presence, extent, and character of wetlands and uplands in the survey area. Vegetation communities were mapped and characterized according to dominant and subdominant plant species. Wetland plant communities were classified according to the *Classification of Wetlands and Deepwater Habitats of the United States* (Cowardin et al. 1979). Surface soil layers and hydrologic regimes of each community type were described. Performance of wetland functions was assessed using the *Method for Assessing Wetland Functions* (Ecology 1999) as a guide.

The two main factors assessed to evaluate mitigation potential were environmental conditions and wetland functional performance. Other factors considered in assessing mitigation potential include site access and potential for re-establishing ecological connectivity.

Most portions of the mitigation potential survey area were considered to have at least moderate mitigation potential. The potential for restoring wetlands appeared low since virtually no areas that were historically drained for agriculture currently lack wetland hydrologic regime. The potential for creating wetlands also appeared low since few upland areas that lack valuable habitat such as mature forest occur on site. In contrast, the potential for enhancing wetlands on site was considered fairly high since degraded wetlands with moderately good conditions for growing native plants are widespread. A few sites considered to have especially high potential for enhancement were identified.

The CMAs were among the sites considered to have very high potential for enhancement for a number of reasons. In brief these reasons include good growing conditions, high potential to enhance ecological connectivity to intact natural communities located nearby, good accessibility, and high likelihood that environmental quality in the area will not degrade substantially over time. These reasons are discussed in more detail in the next section.

5.3.3 Compensatory Mitigation Potential of the CMAs

The large meadow areas encompassing the CMAs are readily accessible to laborers and heavy machinery from adjacent roads. Laborers and heavy machinery will need to access the site during site preparation, planting, and maintenance operations. The ditches separating the roads from the sites can be temporarily bridged to permit all-terrain vehicles (ATVs) carrying mulch and plants to cross them.

The open meadows within CMA2 will facilitate construction of a culvert and inlet channel necessary to direct stormwater runoff to this area from the detention pond proposed for the plant site. Directing stormwater runoff to this area will restore historic drainage patterns and provide additional hydrologic storage and water quality treatment. The broad slope within the site will allow flow to be dispersed across a wide area, improving hydrologic storage and performance of hydrologic functions. Most portions of the ditches within the CMAs could be filled to reduce the sites' overall drainage rates, thereby increasing hydrologic storage. The forest and shrub habitats that will develop in the CMAs will further improve hydrologic storage through increased evapotranspiration and interception of precipitation.

Both CMAs and the meadow areas adjacent are considered to have high potential for establishing a wetland complex including forest and shrub-dominated habitats (URS 2000a). Soils and hydrologic conditions present on site appear capable of supporting moderate to rapid growth of trees and shrubs, thus facilitating the re-establishment of forest and scrub-shrub habitat. Additionally, establishing forested and scrub-shrub habitat may encourage natural colonization by native trees and shrubs in meadow areas adjacent to the CMAs.

Growing conditions at the CMAs are adequate for establishing a variety of native plant communities despite some inherent problems. Although most of the soils are saturated or inundated long enough to become deoxygenated in the upper soil horizon during the early part of the growing season, virtually all areas become fairly dry and the soils well oxygenated as the season progresses. The runoff introduced to CMA2 will considerably increase inundation duration, but even the wettest areas here will continue to become fairly dry during the latter part of the growing season.

Although these areas have been degraded by past agricultural practices, the CMAs have not been cultivated and the ditches on site have not been maintained for at least 10 years. Soil structure, the arrangement of soil particles, has likely redeveloped to some degree over these past few years, improving soil drainage and aeration. Although most of the areas in the CMAs are covered with non-native grasses, native plants can be readily established using appropriate techniques.

Restoring or enhancing habitat types that have been eliminated or degraded by past agricultural practices may greatly bolster local ecological vigor. Re-establishing wetland habitats with mature, native vegetation will contribute to the re-establishment of a key component of the landscape's ecological integrity.

There is high potential for increasing connectivity between the CMAs and ecologically important areas located nearby. Enhancement of CMA1 will create a forested corridor between the Terrell Creek riparian forest and the mature upland forest located atop the hill just north of Grandview Road. Such a connection will improve ecological connectivity between the Terrell Creek riparian forest and the large forested areas south of Grandview Road. These forested areas south of Grandview Road extend south to the Lake Terrell Wildlife Area, a 1,500-acre reserve managed by the Washington Department of Fish and Wildlife (WDFW). These intact forests currently support many native plant species and provide habitat for a variety of wildlife including large mammals such as blacktail deer and coyotes. Connecting these forested areas is also considered desirable for heron, which have been observed preferentially flying along tree lines to reach foraging areas.

Enhancement of CMA2 will broaden the connection established by enhancement of CMA1 to include the area south of Terrell Creek and west of Blaine Road. CMA2 will extend west to the east edge of the existing mitigation site initiated in 2000, connecting this area with the habitat network to be enhanced by the proposed compensatory mitigation. Enhancement of both CMA1 and CMA2 will facilitate wildlife migration and dispersal in the Terrell Creek watershed. Migration and dispersal habitat is especially important to areas like this portion of Whatcom County that retain forested areas heavily fragmented by development. Creation of this corridor will also provide greater opportunities for native plants to exchange pollen and spread seed to and from intact forest and wetland habitats.

If no enhancement occurs in the CMAs, pioneering species such as red alder, hardhack (*Spiraea douglasii*), Himalayan blackberry, and evergreen blackberry will eventually colonize large portions of the seasonally saturated wetlands and upland meadows. The seasonally inundated portions of the wetlands may continue to be dominated by reed canarygrass and the few other herbaceous species present for a long time. Native forest and shrub-land communities may eventually dominate these areas, but not until many decades perhaps centuries have passed. Instead, successional processes can be artificially accelerated to produce forests and shrub-lands with a variety of native vegetation in much less time if appropriate techniques are applied.

5.4 ECOLOGICAL ASSESSMENT OF MITIGATION SITE

The *Revised Cogeneration Project Compensatory Mitigation Areas Wetland Delineation Report* (URS 2003a) details existing conditions within the CMAs including plant communities, soils, hydrologic regime, wetland functions, buffers, and land use. Much of the information from this report is summarized in this section.

5.4.1 Plant Communities

The CMAs and surrounding lands are predominantly composed of grassy areas that were once cultivated for hay. These areas have all been degraded by historic agricultural practices including plowing, planting with non-native grasses, and ditching. However, wetland conditions persist across most of the area. Of the 50.3 acres comprised by CMA1, 38.4 acres (76.2%) were determined to be jurisdictional wetland (see Figure 5A). Of the 59.8 acres comprised by CMA2, 41.3 acres (69.2%) were determined to be jurisdictional wetland (see Figure 5B).

Most of the lands within the CMAs are PEM wetlands dominated by non-native pasture grasses. Approximately 69.8% of the wetlands found in the CMAs are PEM communities that are seasonally saturated, but not inundated (PEMA). Most PEMA wetland areas are dominated by colonial bentgrass, but contain some areas with dominant amounts of soft rush and/or reed canarygrass. The distribution of each species is very patchy, and some patches in most areas are fairly small (100 to 1,000 ft^2). PEMA communities contain a few subdominant species including field horsetail, slough sedge (*Carex obnupta*), tall fescue (*Festuca arundinacea*), and other herbaceous species well adapted to moist, open conditions.

Nearly all of the remaining 30.2% of on-site wetlands are comprised by PEM communities that are seasonally flooded (PEMC). Most PEMC wetlands are dominated by reed canarygrass, soft rush, and/or creeping bentgrass. Species distribution in these communities is also patchy. PEMC communities also contain creeping buttercup (*Ranunculus repens*), field horsetail, meadow foxtail, and slough sedge.

A patchy mix of immature trees, shrubs, and herbaceous species are found lining the several ditches that traverse the CMAs. The vast majority of ditches were excavated in wetland areas and thus are considered portions of those wetlands. Plant species most commonly found along these ditches include black cottonwood, hardhack, Himalayan blackberry, evergreen blackberry, clustered wild rose (*Rosa pisocarpa*), and red alder. Typically, these trees and shrubs are rooted adjacent to the ditch whereas reed canarygrass and/or a few other hydrophytic herbaceous species are rooted within the ditch. Although these ditches are not maintained and are overgrown with vegetation, most ditches continue to facilitate drainage from the CMAs.

Upland areas are interspersed within the wetlands present on site. Upland areas comprise 12.0 acres (23.8%) of CMA1 and 18.4 acres (30.8%) of CMA2. Most of this upland area is meadow that is difficult to distinguish from adjacent wetland meadow areas. Virtually all uplands present in the CMAs are slightly elevated above the wetlands that surround them or are situated on well-drained slopes. However, most uplands in the CMAs typically retain saturation near the soil surface for long periods during the wet season. Upland meadow areas are dominated by non-native pasture grasses, typically colonial bentgrass and common velvetgrass. Some upland meadow areas have substantial amounts of other pasture grasses including quackgrass (*Elytrigia repens*), tall fescue, reed canarygrass, and sweet vernal grass. In addition, small patches of Himalayan blackberry and evergreen blackberry, two non-native, invasive shrubs, are found in both meadow and forested portions of the upland areas.

5.4.2 Soils

Two of the three soil series that predominate in the CMAs are considered hydric since they typically sustain saturation at or near the soil surface throughout extended periods of the growing season. All three soil types are moderately fertile and slightly acidic in the surface layer (Goldin 1992). A more detailed description of the soil types is in the wetland delineation report for the CMAs (URS 2003a).

As mentioned in Section 2.3, most of the soil in this portion of Whatcom County was formed in Bellingham Drift and is underlain by clay till (Goldin 1992). Bellingham Drift is the surface stratigraphic layer underlying a large area encompassing the proposed construction site and CMAs. This layer is 70 to 80 feet thick and is considered to be an aquitard, allowing relatively little water to percolate to Terrell Creek or to the aquifer located below the Bellingham Drift. A profile drawing showing the stratigraphic layers in the area is in Figure 3.3-5 of *BP Cherry Point Cogeneration Project – Application for Site Certification* (Golder Associates 2003d). This drawing is presented in Appendix A.

5.4.3 Hydrology

A very high proportion of precipitation falling across this area is stored in the soil and surface depressions or becomes runoff that enters Terrell Creek as surface water during the wet season and the early part of the dry season. As a result, the main source of water for Terrell Creek is surface water runoff from the 20.8 square mile drainage area, including runoff from Lake Terrell. Although mean annual flow in the lower portion of Terrell Creek (west of the Jackson Road crossing) is estimated to be 20 to 30 cfs (Wenger pers. comm. 2002), the creek has been known to dry up completely most summers (State of Washington Department of Water Resources 1960).

The clay till and low relief found throughout the area greatly decreases vertical and lateral drainage, fostering widespread near-surface saturation and/or shallow inundation during the wet season. The surface soil layers in most areas on site are saturated at or near the surface during most of the wet season. As shown in Figures 5A and 5B, large portions of the CMAs support shallow (typically 1 to 3 inches deep) inundation that persists through most of the wet season. Water depths and soil moisture in the CMAs steadily decline during the latter part of the wet season and the early part of the dry season via evaporation, transpiration, and infiltration. The vast majority of the sites retain low to moderate moisture levels by the end of the growing season. No areas within the CMAs consistently support surface water throughout the year.

Figures 6A and 6B show existing hydrologic pathways and surface flow rates within and downgradient of each CMA. The surface water pathways within the CMAs occur in ditches and natural channels as well as in broad swales where surface water may be dispersed across swales as semi-concentrated flow or across very broad swales as sheet flow. Subsurface pathways were estimated as occurring within the topsoil near the soil surface; this type of flow path is termed interflow. To determine locations of hydrologic pathways, ditches and swales were walked and water was pumped into one important ditch to observe its flow. Observations of topography and observations of water flow during storm events contributed to identifying hydrologic pathways. Various flow observations were also compared to rainfall data collected by the BP meteorological station.

Estimates of flow rates at various locations were made during a 6-month, 24-hour storm event that occurred December 13, 2001. These estimates were confirmed by calculations made using the Soil Conservation Service (SCS) method to predict runoff that would occur on site during the 6-month, 24-hour storm event. The SCS method, or the SCS Curve-Number Method, was created by the US Soil Conservation Service and is a commonly used approach for predicting runoff from watersheds (SCS 1973).

CMA1 drains northward to Terrell Creek (see Figure 6A). The hydrologic input for the ditch is precipitation that falls on the land immediately within CMA1 and the west-facing portion of the hill immediately east of CMA1. The hillslope in the southeastern portion of the site faces northwest at approximately 3.5% grade. The rest of the site is nearly flat, but slopes gently (<1% grade) to the north. A broad, shallow ditch carries surface water north across the site. The ditch is 5 to 20 feet wide and 1 to 1.5 feet below the elevation of land immediately surrounding it.

The ditch contains slowly flowing water during the wet season and shallow standing water and/or no standing water from June through October. The ditch rapidly becomes a well-defined channel after it exits CMA1 to the north. This channel leads through the steeply sloped riparian forest to join Terrell Creek.

A smaller and much shallower ditch is also present in CMA1. This ditch extends from the west edge of the site to the main ditch in the northwestern part of the site. This ditch is situated on a relatively flat grade and does not appear to support any flowing water except perhaps during very large winter storm events. The ditch is approximately 2.5 feet wide and 1 feet deep below the elevation of the land surrounding it. A portion of this ditch appears to have been filled and is now only a hedgerow.

CMA2 drains westward to the extensive wetland system off-site, which drains to Terrell Creek near the crossing at Jackson Road (see Figure 6B). The easternmost 350 feet of CMA2 is fairly flat, but the remaining portions including the 'panhandle' slope west at approximately 2.25% grade. The panhandle is the unofficial title for the northwestern portion of CMA2 located west of the finger of forest that extends north from the large forest situated along the western boundary of CMA2's main section. The panhandle generally slopes west at approximately 2.5% grade, but it does contain some areas as steep as 6%. As with CMA1, historic cultivation has substantially disturbed the site, including the creation of ditches that continue to facilitate site drainage. Most of the site is sloped so that subsurface moisture seeps toward the ditch system that leads west across the site.

Two ditches of moderate depth carry surface water north and west across CMA2. The ditch leading north along the western boundary of CMA2 is 2 to 3 feet wide (bottom width) and 2 to 4 feet below the elevation of land immediately surrounding it. The northern portion of this ditch is just within the large upland forest community. The ditch leading west across the site is 2 to 3 feet wide (bottom width) and 1 to 2 feet deep. This ditch crosses the northern portion of the forest patch located just outside of CMA2. The confluence of the two ditches is located at the western edge of the forest, at the southeastern corner of the panhandle. Below the confluence, the ditch continues west along the southern edge of the CMA2 panhandle and extends off site.

Once off site, the ditch runs through the large forested area west of CMA2. From this point flows splits, with some leading north as sheet flow through a large PEM wetland, then west to Terrell Creek just east of

Jackson Road and the remaining flow following the ditch to two large ponds that drain to Terrell Creek under Jackson Road.

It should be noted that a small, but substantial amount of water from the west-flowing ditch currently leads north to become dispersed across a wide portion of the CMA2 panhandle. Some surface water travels north from this ditch through the seasonally inundated wetland area located northwest of the existing forest patch. A portion of this water seeps westward through the adjacent upland, which is sloped to the west and transmits groundwater at moderate rates through a subsurface soil layer. Near the southern portion of this seasonally inundated area is another location where some flow splits from the ditch to the north. Most of this semi-concentrated flow travels west to a swale that directs flow northward. Surface water in the swale then seeps westward through the adjacent upland, as with the sloped upland discussed above. As a result of this seepage, the seasonally inundated area at the western edge of CMA2 and the forested wetland to the south remain shallowly inundated and/or saturated throughout most of the wet season. Most of the water here seeps west to the ditch that runs north along the east edge of an existing compensatory mitigation site that was established in 2000 (Corps Reference #98-4-02349).

Runoff from the plant site and a much larger area to the south is currently directed to the ditch along the east side of Blaine Road. Water flow in the ditch occurs mainly during the wet season and has been observed to be typically greater than 1 cfs during the wet season. The ditch is lined with rip-rap for most of its length, but does contain enough soil in some spots to support hydrophytic plants. The ditch leads to a concrete culvert that is 3 feet in outside diameter and located south of Terrell Creek. The culvert leads north by northeast down through a narrow thicket of Himalayan blackberry and into the mature deciduous, broad-leaved riparian forest. The culvert descends a 20-40% slope and leads to a 50-foot long gravel channel than connects with Terrell Creek just upstream of the large culvert under Blaine Road. Both the culvert and the channel appear stable and likely do not contribute much sediment to Terrell Creek.

Stormwater runoff from a large portion of the refinery is detained in a detention pond and subsequently pumped to the Strait of Georgia near Cherry Point. Runoff from over 50 acres of undeveloped forest and shrub-land in the northwest portion of the refinery property is directed off-site via ditches and culverts to a Terrell Creek tributary located west of Jackson Road. Stormwater runoff on the northeastern portion of the refinery is routed through a culvert under Grandview Road that leads to a series of ponds and wetlands in the undeveloped area west of CMA2.

The area west of CMA2 contains four ponds connected by wetlands and seasonally flowing channels. The ponds are all permanently inundated and of varying size and shape. The first two ponds in the pond series were constructed by WDFW in the 1990's. The first pond is relatively small (0.25 acre), and the second pond is fairly large (4.5 acres). Outflow from both ponds is controlled by weirs located at each pond's outlet. Although the ponds are intended to provide habitat for waterfowl, these ponds induce water quality treatment by providing approximately 200,000 to 250,000 ft^3 of hydrologic dead storage each winter. Surface water released from the large pond flows through a wide, densely vegetated channel that leads west. A few small wetlands may receive some flow from this channel, but most of the flow enters the third pond after joining runoff from the ditch that leads west of CMA2. Surface water from the third pond, which is approximately 3.5 acres in size, drains through a culvert to the fourth pond, which is approximately 2.5 acres in size. The fourth pond drains to Terrell Creek through a culvert under Jackson Road.

As mentioned earlier, soil moisture levels vary greatly between wet season and the dry season because the difference in precipitation between these periods is exacerbated by the poorly drained soils and their high rates of runoff. Moreover, historical cultivation of clayey soils combined with ditch drainage likely caused the hydrologic regime to fluctuate more than had occurred prior to cultivation. However, the gentle topography combined with the soil structure redevelopment that likely occurred during the past few years without cultivation may have allowed soils in the CMAs to regain some of their inherent permeability and storage capacity, thereby allowing them to moderate hydrologic fluctuation to some degree.

A comprehensive monitoring of the site's hydrologic regime is being initiated. On CMA 1, approximately 6 shallow wells will be systematically located to capture current versus post-mitigation surface and subsurface hydrologic change associated with the ditches. Between 15 and 20 shallow wells will be installed in strategic locations throughout CMA 2 to measure current versus post-mitigation hydrologic patterns. An explanation of the methods, data collection, and results garnered are described in the Cogeneration Project Hydrologic Monitoring Work Plan (Appendix G). The information will be used to improve design and implementation of the mitigation and to provide a means for assessing hydrologic conditions before and after surface water diversions are made. They will be monitored frequently through the end of the mitigation monitoring period. In addition to determining the site's hydroperiod (water level fluctuation) and its spatial variation, monitoring will determine locations and rates of existing and post-mitigation flowpaths, both above the surface and as shallow groundwater.

The areas sampled by each gauge will be delineated and mapped prior to diverting surface water to the site. Surface elevation and hydrologic regime of the area immediately surrounding the gauge will be similar to the area that the gauge is determined to be sampling. It is presumed that changes in hydrologic regime will occur in some areas and not occur in other areas.

The map will be checked for adequacy through observations of on-site conditions after the hydrologic modifications are implemented. The geographic extent of the areas sampled by each gauge as presented in the map may be altered to reflect actual changes in hydrologic regime. Any alterations to the map will be documented and explained in monitoring reports.

5.4.4 Experience

URS designed a 4.6-acre compensatory mitigation site located within the BP Cherry Point property north of Grandview Road (Corps Reference #98-4-02349). This project involved rehabilitating a portion of a PEM wetland including removal of non-native, invasive plants, creating a 0.5-acre seasonally inundated area, and establishing a mosaic of native plant communities. Two years of site monitoring have shown that the wetland rehabilitation is on a trajectory toward success. Approximately 90% of the trees and shrubs installed on site have survived and over 90% of these plants show no signs of stress. Whereas herbaceous cover in most portions of the site is greater than 100%, cover by reed canarygrass, a non-native, invasive weed, has been reduced from over 90% to approximately 12% of the site. A copy of the *Year 2 Monitoring Report for Wetland Compensatory Mitigation, 4.58 acres BP Cherry Point Refinery* (URS 2002) is in Appendix D.

5.4.5 Exotic (Non-Native, Invasive) Species

The proposed mitigation will control the non-native, invasive plants growing in the CMAs. Non-native plants dominate most portions of the CMAs. As with the Restoration Areas, only reed canarygrass, Himalayan blackberry, and evergreen blackberry are considered invasive, which signifies that they can be highly competitive and difficult to control. Thus, these species will be the focus of the non-native, invasive species control program.

As discussed earlier, most wetland areas of the CMAs are dominated by intergrading patches of reed canarygrass, bentgrass, and soft rush. Most of the upland areas are dominated by non-native pasture grasses such as colonial bentgrass, velvetgrass, and tall fescue. A few uplands contain patches of Himalayan and evergreen blackberry growing apart from and/or entangled with native trees and shrubs.

The existing distribution of reed canarygrass across the CMAs was mapped by use of a Global Positioning System (GPS) with sub-meter accuracy (Figure 7A and 7B). Three categories of reed canarygrass cover were defined to guide the mapping effort: 1) <20% cover, 2) 20% to 95% cover, and 3) >95% cover. The cover categories used to gauge reed canarygrass distribution reflects actual conditions on site. The limited number of categories facilitated the mapping effort. The area covered in reed canarygrass for each category is presented in Table 10.

Table 10
Existing Reed Canarygrass Cover

Cover Category	CMA1 (acres)	CMA2 (acres)	Total (acres)
<20%	25.43	38.44	63.87
20-95%	15.36	12.42	27.78
>95%	9.57	8.93	18.50

The total area that supports greater than 20% cover by reed canarygrass is 46.28 acres, which is about 42% of the total area encompassed by the CMAs. Although 9.5 acres smaller than CMA2, CMA1 contains a larger amount of area with greater than 20% reed canarygrass cover. This pattern correlates to the higher proportion of wetland area in CMA1. The vast majority of reed canarygrass found in the CMAs occurs in wetlands. However, a few on-site upland areas support reed canarygrass, including a few patches with greater than 20% cover.

As with the Restoration Areas, control of non-native, invasive plant species will consist of a three-pronged approach: 1) initial removal, 2) subsequent maintenance for short-term control, and 3) establishment of native plant communities for long-term control. This approach will be applied to all areas within the CMAs. The first two prongs of the three-pronged approach will be applied to the areas between the CMAs and the ditches within the ROWs.

Removal will occur through a combination of mowing, tilling, and herbicide application. Subsequent maintenance will mainly employ hand-pulling and herbicide application, but may involve some mowing as well. Native trees and shrubs will eventually provide enough shade and organic litter to suppress growth of non-native, shade-intolerant plants from large portions of the site.

Those areas that have greater than 20% cover by reed canarygrass will be regularly mowed for two growing seasons prior to the initial phase of planting. Frequent mowing during this time will diminish the reed canarygrass population in these areas by removing above-ground plant matter, depleting carbohydrate reserves, and suppressing seed production. Any small patches of reed canarygrass found within areas mapped as having <20% cover by reed canarygrass will be mowed or sprayed with herbicide.

Clumps of Himalayan and evergreen blackberry that are not intertwined with native trees and shrubs will be mowed with a brush-cutter. Blackberry that is intertwined with trees will be removed by hand to prevent damage to native vegetation. Cut stems may be mechanically chopped to pieces less than 0.5 foot in length with a crop chopper and may be left on site to serve as mulch.

Those areas that contain greater than 20% cover by reed canarygrass will be tilled. Tilling will occur after mowing during the growing season prior to the initial phase of planting. A large rototiller pulled by tractor will till soils to a 6-inch depth. These portions of the site will then be disked to further break up the clods and kill rhizomes that survived the mowing. Areas with less than 20% cover by reed canarygrass will not be tilled since tilling is not necessary or practical to suppress reed canarygrass in these areas and tilling is not critical to establishing native trees and shrubs. However, any stands of reed canarygrass found in these areas will be mowed and subsequently sprayed with herbicide.

Tilling and disking will fatally damage many of the reed canarygrass rhizomes, but will likely encourage buried seeds and undamaged rhizomes to resprout. Reed canarygrass that does resprout will be sprayed with herbicide. The herbicide applied on site will consist of glyphosate plus surfactants and will only be applied to areas free from inundation and unlikely to support inundation within 2 weeks of application. Herbicide will be applied by state-licensed applicators. This sequence of mowing, tilling, disking, and spraying herbicide will work to exhaust energy supplies of the reed canarygrass population. The herbaceous seed mix selected for the tilled areas has been recommended by the Corps of Engineers because it has proven to be effective at competing with reestablishing reed canarygrass.

The second and third components of the three-pronged approach to non-native, invasive plant control will be implemented equally between tilled and untilled areas. As with the Restoration Areas, weed control will occur through a combination of mechanical removal and herbicide application after native plants are installed and the seed mix applied. Although such maintenance is expected to occur throughout most of the 10-year monitoring and maintenance period, the intensity of the maintenance effort should decrease over time. Eventually, native vegetation will serve to suppress non-native plants over large portions of the site by shading and soil resource competition.

The road ROWs and the setback areas between the CMAs and the road ROWs will be regularly mowed throughout the 10-year monitoring period. This will suppress reed canarygrass or any other exotic plants from producing and disseminating propagules to the CMAs from these areas.

As previously mentioned, URS will monitor the success of non-native, invasive species control each year of the 10-year period. Contingencies will be made if control methods fail to attain performance standards, as necessary. For reed canarygrass, the contingency measures consist of targeted efforts to control outbreaks such as manual removal of invasive species, additional spot applications of herbicide, more frequent mowing, and additional plantings and/or seedings in problem areas.

5.4.6 Wetland Functions

The proposed rehabilitation is predicted to significantly improve the performance of several wetland functions. URS assessed performance of wetland functions for each portion of the CMAs using the *Methods for Assessing Wetland Functions* (Ecology 1999). Functional performance of the wetlands under current conditions is documented in the delineation report for the CMAs (URS 2003a).

The wetlands within the vicinity of the compensatory mitigation were broken into multiple assessment units to more accurately evaluate their functional performance. The assessment units are divided by differences in contributing basin and hydrologic regime.

The assessment unit associated with CMA1 is the wetland area within CMA1. Although this wetland extends beyond CMA1 to the east, drainage within CMA1 either leads to the main ditch or to two intermittently flowing channels that are just east of the main ditch. Surface water in the wetland area east of CMA1 drains away from CMA1 and enters a seasonally flowing channel that leads to Terrell Creek several hundred feet upstream of where surface water from CMA1 enters the creek. The contributing basin for the CMA1 assessment unit is comprised by CMA1 and a small upland area southeast of CMA1.

The assessment unit associated with CMA2 includes the wetland within CMA2 and the area to the north and south of the CMA2 panhandle. This area is estimated to be approximately 68 acres in size and does not include the two ponds created by WDFW, the channels leading to them from the culvert under Grandview Road, or the existing mitigation area (see Figure 6B). The assessment unit contains the portion of the large contiguous wetland extending west to the floodplain for Terrell Creek near Jackson Road that generally slopes west at an average 2.5% grade. As a result, most surface water flows west at relatively rapid velocities. The vast majority of the part of this wetland that lies outside the assessment unit slopes west at approximately 1% grade and has relatively slow flow velocities. As a result of the gentle slope, ditch flooding and sheet flow is much more common in the area outside the assessment unit (see *Revised Cogeneration Project Compensatory Mitigation Areas Wetland Delineation Report* <URS 2003a> for more details). The contributing basin for the CMA2 assessment unit under current conditions is comprised by the area within the assessment unit itself. For post-mitigation conditions, the contributing basin also includes the cogeneration facility (33 acres).

The wetlands within the two assessment units both classify as Depressional Outflow wetlands. Because most portions of the wetland within CMA1 have very gentle slope and precipitation appears to be nearly 90% of this wetland's water source, the wetland within CMA1 nearly classifies as a Flat wetland according to the classification system used by the functional assessment method. The CMA2 assessment unit nearly classifies as a Slope wetland since it slopes west at an average of 2.5% grade. However, both wetland areas classify as Depressional Outflow wetlands because they are open basins with subsurface inflow from adjacent uplands, do not receive river or stream flooding, and emit outflow that ultimately leads to a downstream waterbody (Terrell Creek).

The assessment method was also applied to the assessment units under current conditions and under conditions that are expected to develop 25 years after compensatory mitigation is initiated. The completed data sheets for these assessments are presented in Appendix B.

The results of this evaluation are summarized in Tables 11 and 12. The possible range of index values for each function is 1 to 10, where 10 represents the highest level of performance. The acreage of each mitigation area was used to calculate acre-points. As explained previously, acre-point calculation provides a more quantitative means of comparing gains in functional performance induced by mitigation with losses in functional performance induced by the proposed construction. As recommended by Ecology (1999), URS compared the results of the functional assessments for the mitigation areas with those for the construction site to better determine the adequacy of the compensatory mitigation plan to offset the proposed impacts.

Table 11
Comparison Between Functional Performance of the Assessment Unit Associated With CMA1 (38.4 Acres) Under Current Conditions and 25 Years After Compensatory Mitigation Is Initiated

Wetland Function	Functional Indices – Existing Condition	Functional Indices – 25 Years Post Mitigation	Explanation
Potential for Removing Sediments	4/ 153.6	3/ 115.2	Decrease (-38.4 acre points) predicted since area of herbaceous vegetation cover will decrease.
Potential for Removing Nutrients	2/ 76.8	2/ 76.8	No change predicted since the size of seasonally inundated area will not change substantially.
Potential for Removing Heavy Metals and Toxic Organics	4/ 153.6	3/ 115.2	Decrease (-38.4 acre-points) predicted due to decrease in cover by herbaceous vegetation.
Potential for Reducing Peak Flows	4/ 153.6	4/ 153.6	No change predicted since ditch plugging will occur only in the upper portion of the ditch.
Potential for Decreasing Downstream Erosion	5/ 192.0	7/ 268.8	Increase (+76.8 acre-points) predicted due to increase in percent covered by forest and shrub vegetation.
Potential for Recharging Groundwater	3/ 115.2	3/ 115.2	No change predicted since vertical drainage in this area will remain slow.
General Habitat Suitability	3/ 115.2	5/ 230.4	Increase (+76.8 acre-points) predicted due to increase in area with canopy closure, maximum number of strata, number of snags, vegetation class interspersion, large woody debris, water and vegetation interspersion, and number of native plant species.
Habitat Suitability for Invertebrates	2/ 76.8	4/ 153.6	Increase (+76.8 acre-points) predicted due to increase in exposed substrate, vegetation class interspersion, large woody debris, maximum number of vegetation strata present.
Habitat Suitability for Amphibians	2/ 76.8	3/ 115.2	Increase (+38.4 acre-points) predicted due to increase in surface substrate types, water and vegetation interspersion, and large woody debris.
Habitat Suitability for Anadramous Fish	N/A	N/A	No anadromous fish can or will be able to access the site.
Habitat Suitability for Resident Fish	N/A	N/A	No resident fish can or will be able to access the site.
Habitat Suitability for Birds	4/ 153.6	5/ 192.0	Increase (+38.4 acre points) predicted with increase in number of snags, vegetation class interspersion, special habitat features, index for invertebrate habitat suitability, and index for amphibian habitat suitability
Habitat Suitability for Mammals	3/ 115.2	4/ 153.6	Increase (+38.4 acre-points) predicted due to increase in water and vegetation interspersion and forest cover.
Native Plant Richness	1/ 38.4	3/ 115.2	Increase (+76.8 acre-points) predicted due to increase in maximum number of strata, number of native plant species, and decrease in area dominated by non-native plant species.
Potential for Primary Production and Organic Export	6/ 230.4	7/ 268.8	Increase (+38.4 acre-points) predicted due to increase in area covered by woody vegetation.

Table 12
Comparison Between Functional Performance of the Assessment Unit Associated With CMA2 (64 Acres) Under Current Conditions and 25 Years After Compensatory Mitigation is Initiated

Wetland Function	Functional Indices – Existing Conditions	Functional Indices – 25 Years Post Mitigation	Explanation
Potential for Removing Sediments	4/ 256	4/ 256	No change predicted despite increase in seasonally inundated area due to decrease in cover by herbaceous vegetation.
Potential for Removing Nutrients	2/ 128	2/ 128	No change predicted despite increase in seasonally inundated area due to decrease in cover by herbaceous vegetation and no change in soil type.
Potential for Removing Heavy Metals and Toxic Organics	4/ 256	3/ 192	Decrease (-64 acre-points) predicted due to the decrease in cover by herbaceous vegetation despite the increase in seasonally inundated area.
Potential for Reducing Peak Flows	4/ 256	4/ 256	No change predicted since increase in size of seasonally inundated area will not be accompanied by a great increase in outlet constriction.
Potential for Decreasing Downstream Erosion	5/ 320	7/ 448	Increase (+128 acre-points) predicted due to increase in percent area covered by forest and shrub vegetation.
Potential for Recharging Groundwater	2/ 128	3/ 192	Increase (+64 acre-points) predicted due to increase in seasonally inundated area.
General Habitat Suitability	3/ 192	6/ 384	Substantial increase (+192 acre-points) predicted due to increase in area with canopy closure, maximum number of strata, number of snags, vegetation class interspersion, large woody debris, number of water regimes, number of water depth categories, water and vegetation interspersion, and number of native plant species.
Habitat Suitability for Invertebrates	3/ 192	6/ 384	Increase (+192 acre-points) predicted due to increase in exposed substrate, vegetation class interspersion, large woody debris, water and vegetation interspersion, maximum number of vegetation strata present, and inundation depth and persistence.
Habitat Suitability for Amphibians	2/ 128	4/ 256	Increase (+128 acre-points) predicted due to increase in water and vegetation interspersion and large woody debris.
Habitat Suitability for Anadramous Fish	N/A	N/A	No anadromous fish can or will be able to access the site.
Habitat Suitability for Resident Fish	N/A	N/A	No resident fish can or will be able to access the site.
Habitat Suitability for Birds	4/ 256	6/ 384	Increase (+128 acre-points) predicted due to increase in number of snags, vegetation class interspersion, special habitat features, index for invertebrate habitat suitability, and index for amphibian habitat suitability.
Habitat Suitability for Mammals	3/ 192	4/ 256	Increase (+64 acre-points) predicted due to increase in forested cover and connection to high quality forested habitat.
Native Plant Richness	1/ 64	5/ 320	Increase (+256 acre-points) predicted due to increase in maximum number of strata and number of native plant species, and decrease in area dominated by non-native plant species.
Potential for Primary Production and Organic Export	6/ 384	7/ 448	Increase (+64 acre-points) predicted due to increase in seasonally inundated area and area covered by woody vegetation.

The abilities for the CMA1 and CMA2 assessment units to remove sediment from surface water inputs are rated moderate, whereas their abilities to remove nutrients is rated moderately low. According to the results of the functional assessment, sediment and nutrient sequestration is limited by the lack of permanent water, low permeability of the soils, and low level of outlet constriction in each CMA. Sediment and nutrient capture is aided by the high cover of herbaceous vegetation and presence of seasonally inundated areas.

According to the results of the assessment, the performance of these functions will not change 25 years after compensatory mitigation is initiated. Performance is not predicted to change in CMA1 since the proposed topographic and hydrologic manipulations there will not greatly constrict outflow. Despite that inundation frequency, duration, and magnitude will increase considerably in CMA2, the model does not predict any increase performance of sediment and nutrient removal functions due to the expected decrease in herbaceous cover from shading by forest and scrub-shrub vegetation. Since all the runoff from CMA1 is from well-vegetated areas that will remain relatively undisturbed, the opportunity for CMA1 to enact its potential to remove sediments and/or nutrients will be low. Since most sediments in the runoff from the plant site will be removed by the proposed detention pond and oil/water separator, the opportunity for CMA2 to enact its potential to remove sediments and/or nutrients will be low to moderate.

The potential for removing heavy metals is rated moderate for both wetland areas according to the assessment results. Since precipitation provides the vast majority of the water for these wetlands, few toxins enter these wetlands. Thus, toxin removal is a function the wetlands currently have little opportunity to perform. The performance of this function is predicted to slightly decrease below its current level 25 years after compensatory mitigation is initiated. The decreases are predicted for both CMAs due to the expected decrease in cover by herbaceous vegetation. CMA1 and the portion of the assessment unit associated with CMA2 to be unaffected by runoff piped from the plant site will continue to have little opportunity to perform this function in the future. In contrast, the opportunity for the portion of CMA2 that will receive stormwater runoff to perform this function will increase to some degree.

The abilities of the wetlands to reduce peak flows and decrease downstream erosion are rated moderate according to the results of the assessment. The performance of these functions within the CMAs are limited by the moderate amount of seasonally inundated areas, low amount of woody vegetation, and low level of outlet constriction. However, the high ratio of wetland area to contributing basin area enhances the performance of these functions. The opportunity for these functions to be performed is moderate since there is a moderate amount of runoff from the wetlands. It should be noted that the opportunities for the CMAs to reduce peak flows and decrease downstream erosion are currently low to moderate these sites.

Despite the proposed hydrologic modifications, the model does not predict that the potential to reduce peak flows in the CMAs will change. Although the proposed topographic and hydrologic modifications will increase hydrologic storage and reduce peak runoff rates to some degree, the flooding depth, outlet constriction, and ratio of inundated area to sub-catchment area will not increase substantially for either CMA. Although the inundated area within the assessment unit associated with CMA2 will nearly double in size, the inundated area to sub-catchment area ratio does not increase dramatically because the plant site (33 acres) will become part of CMA2's catchment area. As a result, the model does not predict any increase in the ability of either CMA to reduce peak flow. However, directing stormwater to CMA2 will substantially decrease peak runoff rates delivered from the plant site to Terrell Creek. Instead of being directed through a large ditch along the east edge of Blaine Road that leads directly to the creek, runoff piped to CMA2 will be stored on site and in the large area downgradient before reaching Terrell Creek near its crossing with Jackson Road. The opportunity for CMA1 to reduce peak flows will continue to be low to moderate, but will be moderate to high in CMA2 due to the inflow of detention pond runoff.

The ability to decrease downstream erosion is predicted to improve to some degree in both CMAs. Although the peak runoff reduction and downstream erosion control functions are closely related, only the erosion-control function is predicted by the model to improve due to the substantial increase in forest and scrub-shrub vegetation. The woody vegetation will produce improve hydrologic storage and increase hydraulic roughness, thereby reducing runoff and associated erosion from the CMAs. Despite the establishment of woody vegetation, surface water inputs to the CMAs (especially in CMA2, post mitigation) will continue to overwhelm soil storage capacity, thereby perpetuating the relatively high surface water runoff from the sites. The opportunity for CMA1 to decrease downstream erosion will continue to be low to moderate, but will increase to a moderate to high level in CMA2 where runoff will be delivered from the plant site. Hydrologic storage in CMA2 will reduce the erosive power of the plant site runoff, which would be much higher if all of it was funneled to the large ditch east of Blaine Road.

The potential for the assessment units to recharge groundwater is rated to be moderately low due to the poor vertical drainage of their soils. Because of the more widespread inundation in CMA1, this area is rated to have slightly higher potential to recharge groundwater than CMA2 assessment unit. Infiltration rates are very slow within the BP Cherry Point property and surrounding areas because of the soils here are underlain by a thick stratigraphic layer high in clay and silt (Bellingham glaciomarine drift). Terrell Creek receives virtually no base flow from groundwater sources (State of Washington Department of Water Resources 1960).

Results of the assessment predict that the potential for the CMA1 to recharge groundwater will remain at the current level, yet the potential for CMA2 to recharge groundwater will increase slightly. CMA1's potential is not expected to change since the increase in inundation due to the proposed topographic and hydrologic modifications will not be very large. In contrast, the extent of seasonally inundated area in the assessment unit associated with CMA2 is expected to nearly double. This increased inundation will cause greater amounts of ground water to be stored in the soil within and downgradient of CMA. Given the very low permeability and infiltration capacity of the soils in the area, the opportunity to recharge groundwater stored in stratigraphic layers below the soil will remain low for both CMAs.

The proposed rehabilitation will substantially improve habitat suitability functions on site. Suppression of non-native, invasive plants and establishment of native vegetation will enhance wildlife habitat as well as increase primary production and organic export. Establishing native plant communities will create more habitat structure and diversity, which will likely augment both wildlife and plant diversity. Given the proximity of relatively intact habitats such as mature forests, streams, lakes, and coastal habitats, the opportunity for these wetlands to perform the habitat suitability functions will be moderate to high.

The increased extent of inundation to occur in CMA2 and the native emergent vegetation and woody debris to be established in inundated portions of both CMAs will provide increased opportunities for aquatic insects and amphibians to find cover, food, and breeding sites. The absence of surface water in late summer will continue to prevent colonization by organisms such as bullfrogs, a non-native amphibian species that preys upon amphibian larvae (Richter 1999). Pacific chorus frogs and red-legged frogs are present in nearby areas and will likely colonize the enhanced wetlands in only a few years following their installation.

Other wildlife likely to benefit from the proposed compensatory mitigation includes mammals and birds. Mammals that rely upon woodland and woodland/meadow edge habitat such as blacktail deer, coyotes, Douglas squirrels, raccoons, and porcupines will benefit from the establishment of forest and scrub-shrub communities. A wide variety of birds will likely find nesting and/or foraging habitat in the CMAs 25 years following initial mitigation activity including warblers, sparrows, swallows, woodpeckers, hawks, and shrikes.

Upon reaching maturity, the trees and shrubs to be installed will provide habitat for a variety of wildlife including mammals, birds, and amphibians. The forested and scrub-shrub areas will provide shelter and thermal insulation for many species, which is especially important during winter. These habitats will permit nesting and breeding for a variety of species incapable of utilizing the open meadows for such activities. The wooded areas will also serve as a migration and dispersal corridor connecting the forested areas south of Grandview Road with the riparian forest surrounding Terrell Creek to the north. Migration and dispersal habitat is especially important to areas like this portion of Whatcom County where forested areas are severely fragmented by development.

The forested and scrub-shrub areas will encourage the establishment and growth of native mid-story and understory vegetation and suppress invasion by non-native, invasive plants. The forested and scrub-shrub communities to be established on site may eventually expand into adjacent unimproved areas, thereby further enhancing habitat value for the area. However, the model predicts that the increase in native, woody vegetation will suppress improvement of bird habitat suitability, causing no score increase in CMA1 and only an increase of 2 performance points in CMA2.

Aquatic insects, amphibians, and other animals attracted to the enhanced wetlands and uplands will provide increased foraging opportunities for a variety of birds including passerines (perching birds), waterfowl, raptors, and great blue herons. Herons forage for amphibians and small mammals in the shallow ponds and fallow fields north of Grandview Road (Eissinger pers. comm. 2001). Significant areas of open field habitat will be maintained for heron foraging. The quality of these foraging areas will be much improved over their current condition. Herons will profit from the increase in inundated areas with surface water less than 50 cm (20 inches) deep that support amphibians (Short and Cooper 1985). Converting the extensive reed canarygrass on CMA 1 and 2 to another herbaceous cover will benefit herons also while searching for small mammals. Herons have been observed avoiding the tall dense cover that reed canarygrass presents (Eissinger pers. comm. 2003).

No threatened or endangered species are expected to benefit directly from the proposed compensatory mitigation.

Since the wetlands currently do not provide fish habitat and will not provide fish habitat after mitigation activity is complete, the functional performance for Habitat Suitability for Anadromous Fish and Habitat Suitability for Resident Fish can not be evaluated. Thus, the scores for the mitigation wetlands are shown as not ‘N/A’ (not applicable).

The wetland communities to be established on site will continue to generate relatively high rates of primary productivity and release organic matter to downstream areas at moderate rates via the seasonally flowing channels. A substantial increase in primary production and organic export is predicted to result from the proposed rehabilitation. As a result, the proposed mitigation is predicted to cause more biomass to be retained on site (locked up in trees and shrubs) and also produce an increased rate of organic matter release.

In summary, the model predicts that the proposed mitigation will cause generally slight increases in the performance of hydrologic functions and substantial increases in the performance of wetland habitat functions. For CMA1, the index for one hydrologic function (Decreasing Downstream Erosion) will increase, the index for another hydrologic function (Removing Heavy Metals and Toxic Organics) will decrease slightly, and the indices for the remaining four hydrologic functions will not change. For CMA2, the indices for two hydrologic functions (Decreasing Downstream Erosion, and Recharging Groundwater) will increase slightly whereas the remaining four hydrologic functions will not change. Performance of all habitat functions will increase in both CMAs, but increases will be slightly larger in CMA2 assessment unit. The greater performance increase predicted for the assessment unit associated with CMA2 is attributed to the dramatic increase in inundation and the relatively moderate decrease in herbaceous vegetation.

Gains and losses in functional performance from the proposed mitigation have been calculated in acre-points, which is the product of wetland functional performance index and wetland acreage. The Washington State Methods for Assessing Wetland Functions (Ecology 1999) suggests measuring functional performance in terms of acre-points. Although the wetland functional performance is influenced by wetland size, this measurement essentially gives equal importance to wetland functional performance and wetland size. Acre-points or functional units can be used to compare gain and loss in overall wetland functional performance.

The cumulative loss of wetland functional performance that will occur as a result of the proposed construction has been calculated. The results of this calculation are shown in Table 13. A total of ten wetland areas will be eliminated. The temporal loss in functional performance of the 4.66-acre portion of Wetland F that will be restored subsequent to construction was discussed in Section 4.4.4.

Table 13
Wetland Functional Performance Indices and Acre-Points for Existing Wetland Areas That Will be Permanently Eliminated by the Proposed Construction. [1]

Function	Wetland A (1.69 ac)[2]	Wetland B (2.81 ac)[2]	Wetland C (0.88 ac)[2]	Wetland D (5.92 ac)[2]	Wetland F (8.75 ac)[2]		Wetland G (5.46 ac)[2]	Wetland H (0.23 ac)[2]	Wetland I (0.15 ac)[2]	Wetland J (4.39 ac)[2]	Sum (30.58 ac)
					AU-1 (8.15 ac)	AU-2 (0.6 ac)					
Potential for Removing Sediment	4/ 6.76	4/ 11.24	4/ 3.52	5/ 5.45	5/ 40.75	5/ 3.0	4/ 21.84	4/ 0.92	5/ 0.75	5/ 21.95	116.18
Potential for Removing Nutrients	2/ 3.38	2/ 5.62	2/ 1.76	3/ 17.76	3/ 24.45	2/ 1.2	2/ 10.92	3/ 0.69	5/ 0.75	3/ 13.17	79.7
Potential for Removing Heavy Metals and Toxic Organics	4/ 6.76	4/ 11.24	4/ 3.52	5/ 5.45	5/ 40.75	4/ 2.4	5/ 27.3	5/ 1.15	5/ 0.75	5/ 21.95	121.27
Potential for Reducing Peak Flows	2/ 3.38	2/ 5.62	2/ 1.76	4/ 23.68	4/ 32.6	2/ 1.2	2/ 10.92	3/ 0.69	5/ 0.75	3/ 13.17	93.77
Potential for Decreasing Downstream Erosion	2/ 3.38	2/ 5.62	3/ 2.64	5/ 29.6	5/ 40.75	4/ 2.4	3/ 16.38	3/ 0.69	8/ 1.2	3/ 13.17	115.83
Potential for Recharging Groundwater	3/ 5.07	3/ 8.43	3/ 2.64	5/ 29.6	5/ 40.75	2/ 1.2	4/ 21.84	5/ 1.15	1/ 0.15	5/ 21.95	132.78
General Habitat Suitability	2/ 3.38	2/ 5.62	2/ 1.76	2/ 11.84	2/ 16.3	2/ 1.2	1/ 5.46	1/ 0.23	3/ 0.45	2/ 8.78	55.02
Habitat Suitability for Invertebrates	1/ 1.69	1/ 2.81	0/ 0	0/ 0	2/ 16.3	1/ 0.6	1/ 5.46	1/ 0.23	1/ 0.15	1/ 4.39	31.63
Habitat Suitability for Amphibians	2/ 3.38	2/ 5.62	1/ 0.88	1/ 5.92	2/ 16.3	2/ 1.2	1/ 5.46	1/ 0.23	1/ 0.15	1/ 4.39	43.53
Habitat Suitability for Anadromous Fish	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Habitat Suitability for Resident Fish	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Habitat Suitability for Wetland- Associated Birds	4/ 6.76	3/ 8.43	3/ 2.64	3/ 17.76	3/ 23.85	2/ 1.2	2/ 10.92	2/ 0.46	2/ 0.3	3/ 13.17	85.49
Habitat Suitability for Wetland- Associated Mammals	2/ 3.38	2/ 5.62	2/ 1.76	2/ 11.84	1/ 8.15	1/ 0.6	1/ 5.46	1/ 0.23	2/ 0.3	2/ 8.78	46.12
Native Plant Richness	1/ 1.69	0/ 0	0/ 0	0/ 0	1/ 8.15	0/ 0	0/ 0	0/ 0	3/ 0.45	0/ 0	10.29
Primary Production and Export	6/ 10.14	6/ 16.86	6/ 5.28	7/ 41.44	6/ 48.9	8/ 4.8	7/ 38.22	7/ 1.61	9/ 1.35	7/ 30.73	199.33

1 Wetland E and Wetland K will not be affected by the proposed project.
2 These acreages indicate the impact area for each wetland. The temporary loss of wetland functional performance by the 4.66-acre portion of Wetland F that will become the West Restoration Area is tabulated in Table 4 and is discussed in Subsection 4.4.4.
3 The scores for functional performance are averaged for all wetlands to be affected by the proposed project; the score for Wetland F is the sum of its AU's scores weighted by acreage.

Predicted gains in wetland functional performance from the proposed mitigation were compared with predicted losses in wetland functional performance from the proposed construction (see Table 14). With the exception of Decreasing Downstream Erosion, the method predicts that there will be a net loss in the performance of hydrologic functions as a result of the proposed construction and mitigation. With the exception of Primary Production and Export, the method predicts that the proposed construction and mitigation will lead to a net increase in performance of habitat functions.

Table 14
Expected Gross and Net Gains And Losses of Acre-Points

Hydrologic Functions				Habitat Functions			
Function	**Gains from Mitigation**	**Losses from Construction**	**Expected Net Gain or Loss (+ or -)**	**Function**	**Gains from Mitigation**	**Losses from Construction**	**Expected Net Gain or Loss (+ or -)**
Potential for Removing Sediment	33.74	116.18	-82.44	General Habitat Suitability	278.12	55.02	+223.1
Potential for Removing Nutrients	9.32	79.7	-70.38	Habitat Suitability for Invertebrates	278.12	31.63	+246.49
Potential for Removing Heavy Metals and Toxic Organics	-107.06	121.57	-228.33	Habitat Suitability for Amphibians	166.4	43.53	+122.87
Potential for Reducing Peak Flows	4.66	93.77	-89.11	Habitat Suitability for Anadromous Fish	N/A	N/A	N/A
Potential for Decreasing Downstream Erosion	218.78	115.83	+102.95	Habitat Suitability for Resident Fish	N/A	N/A	N/A
Potential for Recharging Groundwater	64.0	132.78	-68.78	Habitat Suitability for Wetland-Associated Birds	171.06	85.49	+86.57
				Habitat Suitability for Wetland-Associated Mammals	102.4	46.12	+56.28
				Native Plant Richness	346.78	10.29	+336.49
				Primary Production and Export	107.06	199.33	-92.27

It should be noted that despite widespread acceptance of the functional assessment method used for this assessment, the accuracy of its results is limited. As indicated in the method's guidelines, the indices do not denote actual functional performance, but only an estimate of performance based on readily observable aspects of a given site and the relationship between these aspects and the various functions. Many of the relationships between site aspects and wetland functions are simply hypothesized relationships because specific information regarding the relationships may be lacking (Ecology 1999). The validity of these relationships may be especially weak for the hydrologic functions.

Analysis of the CMAs' hydrostratigraphy and soils combined with various observations of the site's hydrologic regime have provided further insight into the factors affecting hydrologic functions. The conclusions regarding performance of hydrologic functions that were drawn from these analyses and observations differ to some degree from the results of the functional assessment using Ecology's methods. In particular, it was shown that sloping topography, poor vertical drainage, and long-term saturation and inundation recurrent across the construction site and the CMAs combine to severely limit the potential to reduce peak flows or recharge groundwater in these areas. Other wetland functions, such as the potential to remove sediments, nutrients, and toxins, are also limited to some degree by the combination of topographic, soil, and hydrologic factors found at these sites. Thus, results of the functional assessment may overestimate current performance levels of most hydrologic functions in the construction site and the CMAs.

Although the rehabilitation proposed for the CMAs is expected to improve performance of these and other hydrologic functions, the functional assessment model does not predict large increases in performance. These predictions underestimate the actual improvement expected because the model lacks the sensitivity adequate to account for the changes in site conditions that will be caused by the proposed mitigation. For instance, adding the contributing basin area comprised by the plant site (33 acres) to the assessment unit associated with CMA2 has no effect on the scores for the hydrologic functions.

In addition, the model fails to incorporate the mitigating effect of the proposed detention ponds on the changes in project site's hydrologic regime. Because the ponds are being designed using updated techniques and will include dead storage, they will mitigate performance losses of all hydrologic functions except Potential to for Recharging Groundwater, a function which is not significant on the BP Cherry Point property due to the underlying aquitard.

Thus, the actual performance losses of hydrologic function due to the proposed construction will be less than indicated by the functional assessment results whereas the expected gains will be as great or greater than indicated by the functional assessment results. As a result, the proposed mitigation will adequately offset the losses of hydrologic function performance to be caused by the proposed construction (including detention pond construction).

The proposed mitigation will greatly improve ecological integrity and functionality of the wetlands within the CMAs. Applying Ecology's wetland rating system to the CMA wetlands under conditions predicted to occur 25 years following initial mitigation activity results in Category II wetlands with very high scores, indicating a highly valuable Category II wetland. The existing wetlands within the CMAs are rated as a Category II wetlands using the Washington State Wetlands Rating System (Ecology 1993). Despite their degraded condition, these wetlands satisfy the criteria for Category II status since they are fairly large and hydrologically connected via intermittent streams to Terrell Creek, a salmon-bearing stream with an intact riparian forest. However, they barely exceed the threshold between Category III and Category II wetlands. The completed wetland ratings data forms for the CMAs under current and predicted conditions are presented in Appendix C.

5.4.7 Buffers

The upland areas scattered across various portions of the CMAs share borders with the wetland areas within the CMAs and are thus considered wetland buffers. Most of these upland meadow areas are only slightly higher in elevation than the wetlands and retain saturation for long periods during the wet season. The Upland Forest communities to be established within these areas will improve their service as wetland buffers, thereby enhancing performance of both hydrologic and habitat wetland functions.

The riparian forest associated with Terrell Creek will provide a buffer to most of the northern border of the CMAs. Only the westernmost portion of CMA2 does not border this mature mixed deciduous/coniferous forest. Two patches of mature forest distinct from the riparian forest associated with Terrell Creek also border CMA2. These forests are mainly composed of deciduous broad-leaved trees, but have several native coniferous trees approaching canopy level.

In areas along Blaine Road and Grandview Road, wetlands extend to the edge of the ROW or beyond. In these areas there is no opportunity for designating upland buffers. In other areas of the CMAs, the wetland continues beyond the boundary of the CMA, and these areas likewise have no opportunity for wetland buffers. The latter areas border on other BP property with no active land use, and the functions often provided by buffers are less important or are provided by the wetland.

5.4.8 Land Use

Although the BP Cherry Point property north of Grandview Road is zoned for 'light impact industrial' development, BP intends to maintain this area in a natural state. As stated earlier, the CMAs primarily contain abandoned pasture that has not been cultivated in over 10 years. These areas are currently utilized by the Washington Fish and Wildlife Service (WDFW) to produce grain for ring-necked pheasants, which are released here each autumn for the relatively few hunters that pursue them. These areas endure only occasional human traffic. WDFW in conjunction with Ducks Unlimited has also constructed two ponds, both of which provide habitat for waterfowl. The grain-production areas and ponds are located over several hundred feet from the proposed CMAs and no major conflicts with hunters are expected (Reed pers. comm. 2002).

A large area overlapping most of CMA1 is open to cattle grazing under a 5-year contract with a dairy farmer that began in 2001. Typically, the approximately 60 cows and 25 calves congregate on the hill where they have been fed hay through the winter. However, the cattle are free to enter the wetland through a gate that is open for most of the growing season. During this time, the cattle graze virtually all the herbaceous species present within the grazing area, including slough sedge. Observations of the grazed area in October 2002 found that herbaceous plant species diversity has increased substantially since before the grazing began. In addition, the surface layer of the soil appears slightly disturbed by the trampling effect of the cattle. Since the grazing contract is revocable, the cattle will be readily removed before compensatory mitigation is initiated.

The meadow areas west of CMA2 and east of CMA1 are also within the BP Cherry Point property and therefore will be retained as undeveloped areas. The riparian forest to the north serves as the buffer area for Terrell Creek and thus is off-limits to development.

Current and expected future land uses in the area near the CMAs are not likely to deter enhancement of the CMAs or degrade their functional performance over time. Air quality modeling indicates that emissions from the cogeneration facility will not significantly affect current ambient air quality in the area (Golder Associates 2003d). Although residential development may increase to some degree over the next few decades, the areas adjacent to the CMAs will likely retain their rural character. The nearest properties to the CMAs outside BP ownership are north of Terrell Creek and are approximately 0.25 miles away. Although it currently conveys light to moderate traffic, Blaine Road and the portion of Grandview Road east of the intersection with Blaine Road (also known as State Route 548) is not likely to be expanded at any time (Lee pers. comm. 2003). Since the portion of Grandview Road west of its intersection with Blaine Road conveys only light traffic, this area will not likely be expanded either.

5.5 CONSTRAINTS

Vandalism by trespassers may be the only constraint to mitigation success that is outside the owner's control. However, no vandalism has occurred to the existing mitigation site located just west of CMA2 and none is expected to occur in the CMAs. The mitigation sites are within BP Cherry Point property near the refinery and currently undergo regular security checks by the existing security contractor.

5.6 SITE PLAN

5.6.1 Hydrologic Modifications

The hydrologic modifications proposed for the CMAs include plugging (filling) portions of some ditches in both CMAs, directing stormwater runoff to CMA2 from the detention pond to be constructed at the plant site, and excavation of swales to ensure that runoff is dispersed across a wide area of CMA2. These modifications will restore historic drainage patterns, further improve water quality of the runoff from the detention pond, and reduce drainage efficiency, thereby increasing hydrologic storage.

The portions of ditches within the CMAs that will not be filled lack the potential to contribute to hydrologic restoration. Because these ditches convey relatively high flows during winter storm events, filling them would likely cause erosion (possibly gullying) and ultimately not improve hydrologic storage or performance of hydrologic functions on the site.

Figure 8A contains the plan drawing showing modifications proposed for CMA1 and Figure 8B contains cross section drawings detailing ditch plugging proposed for CMA1. Figure 9A contains the plan drawing showing modifications proposed for CMA2 and Figure 9B contains the cross section drawings detailing ditch plugging proposed for CMA2.

The locations of the main ditches within CMA1 and CMA2 as they currently exist are shown in Figure 5A and Figure 5B. Native soil will be used to plug the upper (southern) portion of the main ditch in CMA1, the shallow ditch that extends east-west in the northwestern part of CMA1, the upper (eastern) portion of the east-west ditch in CMA2, and the upper (southern) portion of the ditch along the west boundary of CMA2.

To the extent practicable, soil from spoils cast adjacent to the ditches will be used to fill the ditches. Soil excavated upon creating the inlet channel and some broad swales will also be used to fill ditches. The areas immediately surrounding the ditches to be filled may be recontoured to further simulate historical topography. The areas recontoured as part of the ditch filling and swale creation will be planted and seeded with native plants.

Directing stormwater runoff to CMA2 will require piping runoff from the proposed detention pond for the plant site to a channel that will be constructed in the eastern portion of CMA2. Treated runoff from the detention pond will be directed west along the south edge of Grandview Road and then north through a culvert to be installed under Grandview Road. Runoff will then lead north through an approximately 1,050-foot long inlet channel to be excavated near the east edge of the site.

The inlet channel will be constructed to match the existing very gradual slope (0.3%) with a two-foot base and half-foot depth below the existing ground surface. Additional depth within the channel will be created by constructing berms to surround the channel. Except for the sections of the berm that will serve as outlets, the berm will be constructed of compacted fill excavated from other portions of CMA2. The channel bottom and berms have been designed to tolerate colonization by unmaintained vegetation.

Six ‘disperser outlets’ consisting of 75-foot wide sections of permeable material (coarse sand and gravel) will be installed in the western berm. The disperser outlets will be constructed at strategic locations along the western berm of the channel so that runoff will be spread across a wide portion of CMA2. The disperser outlets will also dissipate flow energy, releasing water at relatively low rates to prevent erosion. The stormwater will seep through the gravel and continue westward down the slope as sheet flow and semi-concentrated flow. Construction drawings detailing the inlet channel and its disperser outlets are shown in Figure 9C.

The inlet channel is designed to provide dispersed stormwater flows to CMA2 while limiting grading activities within existing areas. The channel is placed near the top of a broad west-facing slope within CMA2. The shallowly excavated channel will allow flow to exit the channel through the disperser outlets during most wet season storm events. To ensure even distribution of flow amongst all the disperser outlets, water levels in the channel will be controlled by adjustable weirs or similar devices. The culvert outlet (inlet to the inlet channel) will also be designed to allow minor adjustments in constriction. With these adjustable features, minor changes in channel flow may be made during the first 1 to 2 years after installation to maximize flow dispersal. If necessary, further adjustments with these features may be made as site conditions change.

Flow from the northern portion of the inlet channel will lead west and northwest through three broad swales to be excavated within the upland area that exists just west of where the inlet channel will be constructed. Although it is not clearly shown in Figure 5B, the existing elevation of the eastern portion of this upland area is slightly above the location of the proposed outlets in the northern portion of the inlet channel. Thus, creating these swales is necessary to encourage overland flow to continue westward to prevent it from flowing southward as a result of the existing topographic obstructions. As a result, it ensures that runoff will be dispersed over a wide area. Excavation of the swales will lower surface elevations no more than 1 foot across portions of the upland that are approximately 50 feet wide. The slope and aspect of these swales will remain very similar to existing conditions, but the lowered elevations will allow surface water to flow through them. Cross-section drawings detailing swale excavations are shown in Figure 9D.

The inlet channel will not be extended across the entire length of CMA2 (approximately 1,600 feet north-south) because the topography north of the existing east-west ditch does not permit overland flow to travel westward. Several seasonally inundated wetland areas currently convey flow in ephemeral minor channels southward to the ditch. Any runoff introduced to these wetlands would be captured by these minor channels and carried to the newly filled ditch. The channel stops short of this ditch to prevent directing flows there that would erode newly placed material. Thus, extending the inlet channel to its proposed terminus maximizes flow dispersal across CMA2 without creating a potential source of erosion and siltation.

5.6.2 Post-mitigation hydrologic pathways and rates

Figures 10A and 10B show the expected post-mitigation hydrologic pathways and surface flow rates within and downgradient of each CMA as a result of the proposed hydrologic modifications. As with existing conditions, post-mitigation flow will occur in ditches, in natural channels, over wide areas as sheet flow, and through subsurface pathways.

Stormwater runoff from the two proposed detention ponds will be directed to areas north of Grandview Road and west of Blaine Road. The majority of discharges from the detention pond for the plant site will drain to CMA2 via the culvert that will be constructed under Grandview Road just west of its intersection with Blaine Road. The pond will be designed so that only when outflow rates exceeding the rate expected to occur during the 6-month, 24-hour storm will pond runoff be directed to the existing culvert under Grandview Road that leads to the large ditch along the east side of Blaine Road. According to preliminary calculations derived from the original detention pond design work (Golder Associates 2002), outflow from this detention pond during the 6-month, 24-hour storm event will be approximately 1.33 cfs. All discharges from the detention pond for Lay-Down Areas 1, 2, and 3 and the contractor's parking lot will drain to a ditch that currently leads to a culvert under Grandview Road to a series of ponds and wetlands connected by well-vegetated channels and swales.

Estimates of flow rates were made for the 6-month, 24-hour storm event by summing expected discharge rates for these storms from the detention ponds (as determined by the pond design calculations) and flow rates for existing conditions estimated using the SCS method. The increase in flow rate in ditches and channels downgradient from the input points is predicted to be slightly less than the increase in flow rate at the input points due to flow attenuation by soil and depressional storage. Although flow will be progressively reduced as it travels downgradient, these reductions will not be equally progressive due to variations in topography and vegetative roughness.

Filling the upper portion of the main ditch and the entirety of the minor ditch in CMA1 will reduce drainage rates from this site. However, the extent of seasonally inundated area is only expected to increase near the upper portion of the main ditch since the minor ditch supports relatively low flow rates.

The proposed hydrologic modifications will slightly increase constrictions to surface water flow both CMAs. Filling large portions of existing ditches will reduce the rate of surface water drainage, thereby increasing the extent of seasonal inundation. The frequency, duration, and magnitude of inundation will increase substantially in low-lying areas immediately upgradient from the portions of the ditches that will be filled. In CMA1, this area is constricted to the area near the main ditch south of the existing aspen stand (Figure 10A). In CMA2, the increase in seasonally inundated area will be greatest immediately downgradient of the inlet channel, east of the forested patch, and south of the forested patch (Figure 10B).

Runoff released from the proposed inlet channel will flow westward across a wide portion of CMA2 and downgradient areas. From the disperser outlets, surface water will flow west and northwest as sheet flow and semi-concentrated flow. Flow from the southern portion of the inlet channel will lead westward across CMA2 and off-site to the south of the large forested patch located just west of the main body of CMA2.

Surface and ground water flow that would have been directed north by the existing ditch along the west edge of CMA2 will instead go further west due to the proposed ditch plugging. This water will then lead north and then west across a broad meadow area until it enters the relatively flat wetland area just east of the large WDFW pond.

Flow from the northern disperser outlets will lead to the seasonally inundated area located just east of the large forested patch. The additional surface water introduced to the seasonally inundated area will cause it to have increased duration, magnitude, and frequency of inundation. This area will drain to the portion of the west-flowing ditch that runs through the northern part of the large forest patch. Flow in the west-flowing ditch follows a somewhat complex path, but most flow eventually joins Terrell Creek near Jackson Road.

As mentioned earlier, a substantial amount of water from the west-flowing ditch currently leads north to become dispersed across a wide portion of the CMA2 panhandle. It is expected that a substantial amount of water introduced by the inlet channel will follow these existing pathways and increase moisture levels across a wide portion of the CMA2 panhandle. As a result, the extent of seasonally inundated area in the panhandle will increase in areas where shallow inundation currently occurs.

The drainage pathways west of CMA2 are complex and extend for over 0.5 mile through ponds, connecting channels, and wetlands before crossing by culvert under Jackson Road to Terrell Creek. Thus, runoff delivered to these areas will more closely follow historic drainage patterns rather than being ditched or tightlined directly to the creek. In addition, the potential to improve water quality of this runoff will be maximized. The runoff will also provide additional surface water to the ponds, most of which have their levels controlled by artificial structures such as culverts and weirs.

It must be noted that at least 1.2 acres of existing upland scattered across the main body of CMA2 are expected to become wetland. These areas are mainly on slightly elevated ground near areas that will likely be subjected to increased soil saturation and inundation. At least 0.25 acres of this wetland conversion area consists of the three swales that will be excavated from the existing upland in the eastern portion of the site. Although the likelihood of conversion is high, it is not high enough to allow BP to gain extra mitigation credit for creating wetlands.

5.6.3 Soil

The native soils within the CMAs will serve as an adequate growing medium for the plants to be installed. Most of this soil typically consists of a silt loam or loam surface layer that is 10 to 14 inches deep. Subsoil layers are typically silt loam or sandy loam that are 8 to 16 inches thick. See the *Revised Cogeneration Project Compensatory Mitigation Areas Wetland Delineation Report* (URS 2003a) for more information about on-site soils.

Soil disturbed by tilling or filling may be covered with mulch or erosion-control matting to prevent soil erosion. These areas will then be replanted with native vegetation as soon as practicable. The created swales and filled ditches in both CMAs will be designed to encourage colonization by vegetation and will be seeded with the native seed mix.

5.6.4 Habitat Features

A number of habitat features will be distributed across the CMAs. The habitat features planned for the site will provide structure to encourage habitat utilization by native wildlife species.

At least 330 downed logs (3 per acre) will be placed across the CMAs. Some of these logs will be derived from the trees that will be removed for construction of the Cogeneration Project. A few others will be taken from the downed logs recently created by construction of an access road on the BP Cherry Point property south of Grandview Road. In addition, approximately 55 non-native cedar (*Cupressaceae* family) trees will be cut from a windbreak that protects an abandoned orchard plot located just north of CMA2. The windbreak trees are approximately 30 feet tall with 8-inch dbh. The proposed tree cutting will reduce the tree density to 9-feet on-center, which will allow the remaining trees to accelerate their lateral and vertical growth. The logs will act as habitat features by providing foraging opportunities, cover, and perching or haul-out sites for small mammals, birds, and amphibians (Stevens and Vanbianchi 1993).

A number of artificial snags (dead-standing trees) and wildlife brush shelters will be erected on site. In addition, woody branches will placed in seasonally inundated areas. The materials, specifications, and benefits for these habitat features will be as described in Section 4.6.4.

Several small (<0.5 acres) seasonally inundated shallow ponds will be established on CMA 1 and 2 to promote native amphibian production. Seasonally inundated ponds dry up during the dry season making it impossible for non-native bullfrogs to successfully breed because of their two year tadpole cycle.

Habitat features are designed to benefit the local breeding great blue heron population. Woody debris, eradication of invasive vegetation, and establishment of small seasonal ponds all provide increased opportunity for heron foraging. Details of these benefits are available in the appendix F – *BP Cherry Point Cogeneration Facility Wetland Mitigation and the Birch Bay Great Blue Heron Colony*.

5.6.5 Vegetation Establishment

The distribution of plant communities to be established in CMA1 is shown in Figure 11A and the distribution of plant communities to be established in CMA2 is shown in Figure 11B. The plant communities planned for the CMAs are the same as those planned for the Restoration Areas. Plant species composition, spacing, condition, and size for these communities are shown in Tables 5 to 8 and discussed in Section 4.6.5. The requirements for the Restoration Areas regarding plant stock, installation, seedling protection, and maintenance will also apply to the CMAs.

As with the Restoration Areas, planting will be accomplished in a multi-phase approach. Planting will be especially limited across portions of CMA2 to be affected by the proposed hydrologic modifications in the first 1 to 2 years following the implementation of the hydrologic modifications. This will prevent subjecting large numbers of installed plants to a hydrologic regime inappropriate for their establishment and allow greater flexibility in treating reed canarygrass. Close observations of the new hydrologic regime over the first few years will help guide placement, species composition, and condition of the plants that will be installed during this time.

The seed mix depicted in Table 8 will be applied to the interstitial areas between installed plants wherever tilling occurs in the CMAs. As discussed earlier, tilling will occur prior to the initial planting phase in all of the 44.26 acres mapped as having ≥20% reed canarygrass cover. However, the mix will only be applied to the interstitial space between mulch rings, which should comprise approximately 85% of the tilled areas. Thus, the actual area upon which this seed mix will be applied is 37.3 acres. As with the Restoration Areas, the total seeding rate will be 40 pounds per acre, which is a relatively high seeding rate for mitigation areas.

5.6.6 Irrigation

The methods of irrigation proposed for the Restoration Areas will also be applied to the CMAs. All portions of the CMAs where trees and shrubs are installed will receive irrigation.

Given typical summer precipitation amounts, providing 0.5 inch of water per week to the CMAs (110.1 acres), the Restoration Areas (9.3 acres), and the visual buffer to be forested (1.8 acres) will require approximately 124,000 gallons of water per day. This volume is roughly equivalent to 0.38 acre-foot per day or 0.19 cubic foot per second (cfs). If summer precipitation is 30% below normal, then meeting the irrigation goal will require approximately 323,400 gallons of water per day. This volume is roughly equivalent to 0.99 acre-foot per day or 0.5 cfs.

Normal rainfall is considered a monthly or yearly amount that is above the lower 30% and below the upper 30% (z-values between –0.524 and 0.524 according to the standard normal distribution) of the amounts shown in NRCS's WETS table (NRCS 1999) for the Bellingham International Airport. Although this weather station is no longer operating, precipitation data from this station located within 12 miles of the CMAs spans over 20 years and is therefore a reliable source for comparison with current and future precipitation data.

6.0 CONSTRUCTION SPECIFICATIONS & AS-BUILT REPORT

Installment of topographic and hydrologic modifications, habitat features, plants, seeds, mulch, soil amendments, erosion control matting, and other features within the mitigation areas will be achieved by local contractors with proven experience. Work requiring heavy machinery, such as the proposed topographic and hydrologic modifications, will likely be awarded to Donaghy Construction, a local firm that was provided construction services to BP Cherry Point for many years. Other work that is more labor-intensive, such as installing native plants, will be rewarded to a local bidder that demonstrates competence and relevant experience.

Upon completion of the mitigation areas construction, an as-built report will be generated documenting the final grading, hydrologic pathways, and planting schemes. The report will include the elements recommended in *Guidelines for Developing Freshwater Wetlands Mitigation Plans and Proposals* (Hruby and Brower 1994). The as-built report will provide a time zero baseline comparing the actual changes in site hydrology, identifying the success of invasive vegetation eradication, and the final woody and herbaceous plantings layout. The report will also include photographs of the wetlands taken from permanent reference points. The baseline information will be used for calculating the success of the performance standards in subsequent monitoring reports and assist in identifying required planting replacements, if needed.

The primary source for plant materials and fertilizer will be Fourth Corner Nurseries, which is located in Bellingham. The plants that they provide are primarily derived from stock taken from lowland areas in Whatcom County.

As with the existing compensatory mitigation site, the primary contractor that will supply maintenance for the mitigation areas will likely be Berry Acres. Berry Acres is a professional landscaping company that has been providing landscape maintenance services to BP Cherry Point for several years. URS will regularly communicate with the contractors who will carry out maintenance tasks. The maintenance crew will be responsible for operating the irrigation system, controlling exotic plant populations, providing plant protection (replacing seedling protection tubes), and regularly reporting to URS ecologists who will make recommendations for adjusting the maintenance regime as necessary.

7.0 SITE PROTECTION

A restrictive covenant on the deed will be applied to the Restoration Areas and CMAs to ensure that they remain in their respective natural states in perpetuity. No development of the CMA portions of the BP Cherry Point property will be allowed for any purpose by any entity whatsoever. The restrictive covenant on deeds pertaining to the restoration areas shall restrict all activities except those associated with maintenance of utilities and their corridors. Any clearing, grading, or filling will be prohibited except to achieve changes required to meet mitigation requirements or further improve performance of wetland functions. No deposition of materials or fills as a result of any clearing, grading, or development of any property will be allowed. The restrictive covenant will run with the land and inure to the benefit of and be binding upon BP, their successors, and assigns.

To temporarily protect the restored areas from human trespass, brightly colored rope fences will be strung on wooden stakes around the perimeter of each Restoration Area and each CMA. The fences will be intended to discourage people from disturbing the installed plants through physical harm and incidental introduction of non-native, invasive grass seed. The fences will remain in place for 5 years or until it is judged that the installed plants within the mitigation areas no longer require such protection. Small signs explaining the intent of the fences and the mitigation project will be erected at strategic locations along the borders of each mitigation area.

The people who will access the Restoration Areas will be restricted to BP employees and official visitors to the BP Cherry Point facilities. The chain-link/barbed-wire fences to be erected around the Cogeneration Project area will encompass each Restoration Area, thereby preventing trespassers from accessing these areas. Except for maintenance crew people and URS scientists, access to the Restoration Areas will be restricted to the walking path to be constructed in the West Restoration Area. Colored rope fence will be installed along both sides of the path to encourage people to stay on the walking path and not disturb the Restoration Areas.

Public access to the portions of the BP Cherry Point property north of Grandview Road, which encompasses the CMAs, will continue to be open to the public. The majority of the people that access these areas are the hunters that pursue ring-neck pheasants released here during early autumn. BP will continue to allow pheasant hunting and other activities in these areas as long as they cause no harm to the CMAs.

Cattle, or any other domestic animals, will no longer be allowed to graze in any of the mitigation areas. The grazing contract for the area overlapping with CMA1 would be revoked or modified to prevent cattle from grazing within 100 feet of this area.

Regular security checks by the existing security contractor will discourage vandalism in the CMAs, although it is not expected to be a problem.

8.0 MONITORING PLAN

The purpose of monitoring and maintenance is to ensure that mitigation plan goals are met. Construction of the power plant and the lay-down areas will be monitored to ensure that wetland impacts are avoided and minimized according to plan. The Restoration Areas and CMAs will be monitored over a 10-year period to ensure that these areas function as designed.

Monitoring of the proposed restoration and compensatory mitigation will be guided by the conditions contained in this plan including pre-established performance standards. A 10-year monitoring plan will be implemented to assess the degree to which objectives and performance standards (Section 3.3) are being met. Monitoring will be conducted by a URS biologist immediately following the initial planting, and 1, 2, 3, 5, 7, and 10 years afterward.

Maintenance will be guided by maintenance actions required by this plan (Section 9) and any recommended contingencies made following implementation of the plan. The majority of maintenance activity will be directed towards removing non-native plants that resprout after initial suppression. However, other maintenance actions tending to the proposed hydrologic modifications and the installed plants may also be necessary. Contingency measures will be recommended and subsequently implemented if site conditions fail to attain expectations. Expectations of site performance are elucidated by the performance standards, which are discussed in Section 3.3 of this report.

8.1 CONSTRUCTION MONITORING

A URS scientist will monitor construction operations regularly during the time of construction. The scientist will monitor operations to ensure that impacts only occur in areas where they have been designated to occur. Vegetation clearing and fill placement will be monitored regularly.

Contingencies will be made if the extent of impacts is greater than expected. All unexpected impacts will be compensated by enhancements of equal or greater value to the compensatory mitigation. Monitoring results will be compiled in a construction monitoring report. The report will be sent to the Corps, Ecology, and EFSEC. Any discrepancies between expected and actual impacts will be mentioned in the report. In addition, contingencies used to compensate for these unexpected impacts will also be mentioned.

8.2 RESTORATION AND COMPENSATORY MITIGATION MONITORING

Monitoring procedures for the Restoration Areas and the CMAs will be similar. Monitoring will determine whether site conditions are meeting performance standards and are likely to continue meeting performance standards throughout the monitoring period. Since removal of the temporary lay-down areas and the subsequent restoration will begin approximately 2 years after project construction is initiated, the monitoring period for the Restoration Areas will begin approximately 2 years after the monitoring period for the CMAs begins.

8.2.1 Wetland Hydrology

Monitoring will assess the hydrologic regime of the Restoration Areas and the CMAs. This monitoring effort will determine whether a wetland hydrologic regime is occurring in the wetlands restored in the Restoration Areas and will generally characterize the hydrologic regime of both uplands and wetlands in both the Restoration Areas and the CMAs.

At least four shallow monitoring wells will be installed in Restoration Areas and six in CMA 1. Between 15 and 20 shallow monitoring wells will be distributed across CMA 2. The majority of the wells will be placed in locations representing typical hydrologic regimes in both the SS and SI wetland areas down gradient of the level spreader. The remaining wells will be installed in locations representing typical hydrologic regimes in the upland areas. Wells will consist of a screened (perforated) pipe installed to the depth of the fine-grained substrate that forms an aquitard and sealed at the soil surface with bentonite and/or grout.

Both surface water gauges and shallow monitoring wells will be monitored within the compensatory mitigation site. Monitoring activities will follow the program outlined in the Cogeneration Project Hydrologic Monitoring Work Plan (Appendix G). For each well and gauge, statistical comparisons will be made between the data collected before and after hydrologic modifications associated with the mitigation are implemented. Special attention will be paid to the level of the free water surface both above and below ground and its fluctuation over time. Inter-annual comparisons will be adjusted by differences in precipitation that occur between the years being compared. As mentioned in Section 3.3.1, those gauges that demonstrate increases in saturation or inundation persistence independent of increases in precipitation levels will be determined to be within areas that have become 'hydrologically restored'.

Depth to soil saturation and free water surface within the wells will be measured during the early part of the growing season, which is the time when soil saturation will most likely be present within wetlands in western Whatcom County.

Observations of standing surface water and groundwater levels will be made in both the Restoration Areas and the CMAs. In addition to well monitoring, groundwater observations will be made by excavating temporary unlined boreholes with a soil corer to depths not more than 18 inches. The holes created by a soil corer are typically less than 3 inches in diameter and thus have very little impact to the site. Boreholes will be excavated across various portions of the mitigation areas that lack standing water during the time of investigation. Depth to soil saturation and free water surface will be measured within each borehole. These observations will be made during the early and middle portions of the growing season.

8.2.2 Hydrologic Modifications

Hydrologic modifications including the diversion of ditch flow through the West Restoration Area, the diversion of detention pond runoff from the plant site to CMA2, and the various ditch plugs to be installed across both CMAs will be monitored for proper operation. These modifications will be inspected at least once every winter or spring while surface water is flowing through the inlet channel and once during the vegetation monitoring event of each monitoring year. Inspectors will determine the structural integrity and stability of channels, pipes, energy dissipaters, and other structures used for the proposed modifications.

Surface water flow and evidence of surface water flow will be observed to determine whether the actual altered hydrologic regime approximates the design. Any unexpected and harmful erosion or flooding will be recorded and appropriate contingencies to reduce and repair damage will be recommended. Monitoring of the modified hydrologic regime will be especially careful and frequent during the first two years after installation. Results of this monitoring, combined with rainfall data analysis, will help guide the location and species composition of any new plants to be placed in areas where the hydrologic regime has been altered.

8.2.3 Vegetation

URS will locate plots along transects that span the width of each Restoration Area and each CMA. Transect locations will be dispersed across the sites using a stratified random approach to prevent biased plot placement. Both transect and plot locations will be recorded by a GPS unit with sub-meter accuracy. The GPS unit will also be used to determine the planned plant community (Upland, SS wetland, or SI wetland) and the pre-mitigation cover by reed canarygrass (<20%, 20-95%, or >95%) for each plot.

Each transect will be oriented longitudinally (north-south) and randomly situated within 100-meter wide (328-foot wide) bands. Each band will be spaced 10 meters apart to prevent transects from being too closely spaced. Transects will be broken into 100-meter long (328-foot-long) segments, which will also be spaced 10 meters apart from each other. Sample plot centers will be randomly selected along each segment during each sampling event (Figure 12).

Plots will consist of an inner circle with a 2-m (6.56-foot) radius encompassed by an outer circle with an 8-m (26.24-foot) radius. Cover of herbaceous vegetation will be gauged within the inner circle whereas cover of installed woody vegetation will be assessed within the outer circle.

Vegetative survival and cover will be visually estimated by experienced URS ecologists. Woody vegetation success will be gauged by percent survival during the first five years and by percent cover during the remaining five years of mitigation monitoring. Herbaceous vegetation will be measured by percent cover throughout the entire monitoring period. Cover of volunteer plants (vegetation not planted or seeded during any planting events) will be measured for both herbaceous and woody species found within the plots. Cover of trees and shrubs, herbaceous plants, and each plant species will be recorded for each plot. Plant cover will be assessed using a geometric cover classification system with the following categories: 0-2%, 2-4%, 4-8%, 8-16%, 16-32%, 32-64%, >64%. This system facilitates precise assessment of plant cover in the lower ranges, which is especially important for monitoring the spread of recently established vegetation.

As recommended by Krebs (1999), at least 1% of the total area to be monitored will be sampled directly. Since each plot will cover approximately 2,162 ft^2 (0.05 acre), at least 10 plots will be used to sample the Restoration Areas and at least 60 plots will be used to sample the CMAs.

Since invasion by non-native, invasive plants will likely be aggressive, monitoring the cover of non-native, invasive species will be persistent and intensive. In addition to monitoring by plot method as described above, URS ecologists will observe and record the distribution and abundance of non-native, invasive plants each spring and summer in every year of the 10-year monitoring period. Eradication of non-native species will be maintained in all mitigation areas, including uplands and buffer areas.

Those portions of the CMAs that currently have greater than 20% cover by reed canarygrass will have a performance standard of <20%. Portions of the CMAs that currently have less than 20% cover by reed canarygrass will have a performance standard of <10%. Since the Restoration Areas will have less than 20% cover by reed canarygrass immediately prior to initiating restoration activity, only the performance standard of <10% will be applied to these areas. As recommended by Krebs (1999), at least 1% of the total area to be monitored will be sampled directly.

Areas with levels of non-native, invasive plants that appear to be approaching or exceeding performance thresholds will be marked in the field so that the maintenance crew can more accurately target their treatment practices. These unacceptable patches will also be mapped by URS ecologists with a GPS unit with sub-meter accuracy. Results of this monitoring will guide recommendations given by URS to maintain cover by non-native, invasive plants below thresholds set by the performance standards.

Although predation of installed plants has not been a problem at the existing mitigation site, URS ecologists will document any evidence of predation that may occur within the mitigation areas. URS will observe the condition of seedling protection tubes and any other protections provided to installed plants. The effectiveness of these protections will also be monitored. URS will ensure that seedling protection tubes or any other protections provided to installed plants will be in working condition.

8.2.4 Photographs

Several photographs taken from permanent photo-points will be used to aid the monitoring effort. Panoramic photographs showing a maximum amount of each Restoration Area and each CMA will be included. Each permanent photo-point will have its respective Universal Trans-Meridian (UTM) point as recorded by GPS and a detailed narrative description referencing its location relative to existing landmarks. Photos from the permanent photo-points will be taken during each vegetation monitoring event in Years 0, 1, 2, 3, 5, 7, and 10 of the monitoring period. For Year 0, photographs will be taken prior to and during initial mitigation activity. Other photographs may be taken during spring to better document each site's flow regime during the wet season. The photos and their respective narrative descriptions will be provided in each monitoring report.

9.0 MAINTENANCE AND CONTINGENCY PLAN

As mentioned earlier, the primary sub-contractor that will supply maintenance crews will likely be Berry Acres, a crew of landscape professionals with experience in native plant installment and exotic plant control. Sub-contractors will report regularly to URS ecologists who will make recommendations for adjusting the maintenance regime as necessary.

Restoration of the Restoration Areas and rehabilitation of the CMAs will be accomplished under an adaptive management strategy. This strategy will entail responding to monitoring results to appropriately and efficiently maintain or improve site conditions.

If monitoring results demonstrate that site conditions fail to meet performance standards, contingencies will be implemented. For instance, if one of the non-native, invasive species attains cover values that exceed their acceptable thresholds, then a more aggressive approach to weed control will be taken. Such an approach may include more frequent applications of herbicide, more frequent hand-removal, and/or more frequent mowing. These actions may be complemented with additional plantings and/or seedings in problem areas.

If a performance standard is not met for any given year, URS will analyze of the cause of failure, propose corrective actions, and present a time frame for implementing these actions. A letter report will be sent to the Corps and Ecology for their approval before implementing the corrective actions.

Even if all performance standards are met, corrective actions may still be implemented if monitoring reveals problems that could lead to poor performance or future problems. For instance, if a breach in the inlet channel is causing erosive flows to be directed through a part of CMA2, then the breach will be repaired to restore sheet flow and the eroded area mended with seed mix, mulch, and/or new plantings, as necessary. Descriptions of such problems and corrective actions taken to solve them will be included in the monitoring reports.

Examples of problems expected during the maintenance period and the corrective actions that will likely be taken to solve them are as follows:

1. **Wetland hydrology.** If wetland hydrology (free water to within 12 inches of soil surface over 22-contiguous days) is not established in at least 4.86 acres of the Restoration Areas and maintained in the existing wetlands within the CMAs, then further topographic or hydrologic modifications will be made to ensure that these objectives are met. Topographic modifications may include re-grading portions of the site to effectively raise the groundwater in these areas. Hydrologic modifications may include adjusting the adjustable weirs to be installed so that more surface flow could enter an area that is not meeting the minimum requirements of wetland hydrology.

2. **Flow dispersal.** If flow is not evenly distributed between all disperser outlets within the inlet channel to CMA2, then the adjustable weirs within the channel will be adjusted to maximize flow distribution. If flow is evenly distributed between disperser outlets, but is not adequately dispersed across the main portion of CMA2, then URS will recommend grading appropriate to maximize flow dispersal. Any grading that occurs after the initial planting will be accomplished during the dry season and with a small grader or shovels to avoid damaging native plants. To prevent erosion, grading would occur during the dry season and the native seed mix would be applied to areas that have been disturbed.

3. **Invasion by non-native, invasive plants.** Weed control maintenance will occur frequently and aggressively to combat invasions before cover by non-native, invasive plants approach or exceed performance thresholds. As discussed earlier, distribution and abundance of weeds will be

monitored every year of the 10-year monitoring period by URS. Those portions of the CMAs that currently have greater than 20% cover by reed canarygrass will have a performance standard of <20%. Portions of the CMAs that currently have less than 20% cover by reed canarygrass will have a performance standard of <10%. Since the Restoration Areas will have less than 20% cover by reed canarygrass immediately prior to initiating restoration activity, only the performance standard of <10% will be applied to these areas. Monitoring results will guide recommendations given by URS to maintain cover by non-native, invasive plants below the above thresholds. Although removal of non-native, invasive plants is expected to occur throughout the 10-year period, the intensity of the maintenance effort should decrease over time. Following any monitoring year when standards are not being met, additional control and replacement measures will be added to maintenance activities. More information about the weed control program is in Section 4.4.3.

4. **Mortality of installed vegetation.** The multi-phase approach to planting described in Section 4.6.5 also follows an adaptive management strategy. URS ecologists will closely observe the various limitations to plant growth that may be present or may develop during the first few years after the initial planting. These observations will effectively guide placement, species composition, and condition of the plants that will be installed during this time. Special attention will be paid to site conditions in those portions of the mitigation areas affected by the proposed topographic and hydrologic modifications. If, during the monitoring period, the woody species survival or areal cover percentage or the herbaceous community percent cover falls below the established performance standard, additional plantings will be used to bring survival and / or percent cover up to stated goals.

   If predation on installed plants by wildlife becomes a substantial source of plant mortality, then corrective action will be taken. If predation is generally restricted to those seedlings that have lost their protection tubes, URS will recommend that these plants be replaced with protection tubes fitted so that they are less likely to fall off. Tubes that have not fallen off their respective plants but appear unstable will be stabilized. BP will budget funds as required to pay for planning, implementing, and monitoring any contingency procedures that may be required to achieve the mitigation goals. The budget will equal approximately 20% of the total cost of the proposed mitigation, which is estimated to be $1.66 million. Thus, the total value of the maintenance and contingency budget will be $332,000. The parent company guarantee, as described in section 11, will be in the total amount that it is estimated that the restoration and compensatory mitigation will cost and thus will be sufficient to ensure that funds necessary for maintenance and to repair problems will be available.

5. **Reporting.** Results of the monitoring will be compiled in monitoring reports that will be delivered to the Corps, EFSEC, and Ecology by October of Years 1, 2, 3, 5, 7, and 10 for each monitoring period. Reports will state monitoring methods, show monitoring results including photographs, compare these results with performance standards, and discuss the site conditions observed. The current year's results will be compared with the performance standards and results from previous years. If monitoring results are below performance standards, maintenance and contingency recommendations necessary to improve success will be made.

Regular maintenance activity and any contingency actions made during the year will also be reported. The effectiveness of these actions will be gauged during site monitoring. An evaluation of the effectiveness of these actions will be included in the reports.

Record drawings showing topography, hydrologic modifications, and plant communities of the Restoration Areas and the CMAs will be drafted after the initial mitigation activity including the initial planting is complete. These drawings will be submitted to the Corps, EFSEC, and Ecology within 60 days of completing the initial planting of each mitigation area.

10.0 IMPLEMENTATION SCHEDULE

10.1 CONSTRUCTION SCHEDULE

The starting time for constructing the Cogeneration Project and installing its associated mitigation is dependent upon when the necessary permits are issued. Although the chronological order and seasonal timing of mitigation actions will occur as discussed below, exact dates for these actions can not yet be determined given the uncertainty regarding the timing of permit issuance. For illustrative purposes, the dates provided below assume that project construction will begin in early 2005.

In the CMAs, activities of the weed control program that do not entail mechanized clearing of wetlands and therefore do not require the above-mentioned permits may begin a few months prior to the construction start date. Such activities, including mowing and herbicide application, will begin in spring 2005. Tilling would be anticipated to occur in spring and early autumn 2005. Non-native, invasive plant removal would continue through the growing season of 2005. Removal would continue as maintenance for short-term control throughout the monitoring period.

The proposed topographic and hydrologic modifications will be implemented and habitat features would be installed in summer 2005. The initial phase of planting in the CMAs would be implemented in autumn 2005. Species known to be less tolerant of winter conditions as seedlings (i.e. western red cedar) and some of the herbaceous plants would be installed in spring 2006. The native seed will be applied immediately after these plants are installed. The remaining plants would be installed over the next 2 to 3 years. Although the inlet channel would have been fully installed for a year, runoff would not be diverted to CMA2 until fall 2006, which would allow the initial phase plants to have established to some degree.

The proposed restoration would begin after the end of the construction period, which is expected to last 1.5 to 2 years. If the construction period began in spring 2005, the initial restoration activity would occur after the temporary lay-down areas were removed in 2007. Initial activity including topsoil import, hydrologic and topographic modifications, and habitat feature installment would occur during summer 2008. Weed removal would also occur at this time as necessary.

The initial seeding of the Restoration Areas would occur in late summer 2005, a few weeks prior to implementing the initial planting phase. Species known to be less tolerant of winter conditions as seedlings and some of the herbaceous plants would be installed in spring 2008. The second phase of seeding would occur immediately after these plants are installed. The remaining plants would be installed over the next 2 to 3 years.

10.2 MONITORING SCHEDULE

As discussed earlier, some form of monitoring will occur during every year of the 10-year monitoring period. Formal monitoring of wetland hydrology and vegetation will occur in Years 1, 2, 3, 5, 7, and 10.

Observations of wetland hydrology will be made throughout the monitoring period. Formal monitoring will include measurements of free water surface elevations in the monitoring wells to be installed in the mitigation areas. These measurements will be taken on a weekly basis for at least four weeks from the second or third week of March on or after March 12 to the second or third week of April during Years 1, 2, 3, 5, 7, and 10. Extrapolations between weekly measurements will determine whether soil saturation in the wetland areas meets the wetland hydrology criterion.

Observations of vegetation, native, non-native, invasive, and volunteer, will be made throughout the monitoring period. Formal monitoring will include estimates of cover using circular plots. These estimates will be made during the early part of summer to ensure that flowering plants will be readily identifiable and data collected will not be skewed by seasonal variation. More specifically, vegetation monitoring will occur between June 21 and July 15 of Years 1, 2, 3, 5, 7, and 10.

10.3 REPORTING SCHEDULE

As stated in Section 10, monitoring results will be reported to the Corps, EFSEC, and Ecology by October of Years 1, 2, 3, 5, 7, and 10 for each monitoring period.

11.0 PARENT COMPANY GUARANTEE

BP Corporation North America Inc will provide a guarantee to the Army Corps of Engineer's to ensure that funds are available to construct or complete the construction of, and for monitoring and maintenance of the compensatory wetland mitigation associated with the BP Cherry Point Cogeneration Project. The Parent Company Guarantee will be used instead of a performance bond to ensure BP's accountability for the proposed mitigation. BP will provide the Parent Company Guarantee to the Corps prior to project construction. The amount of the guarantee will equal the estimated dollar amount that the restoration and compensatory mitigation will cost. The preliminary cost estimate of the proposed mitigation, and therefore the proposed amount of the guarantee, is $1.66 million.

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FIGURES

Appendix C Figure 1 Not Available On-line

Appendix D - Agency Consultation Not Available On-line

APPENDIX F

BP CHERRY POINT COGENERATION FACILITY WETLAND MITIGATION AND THE BIRCH BAY GREAT BLUE HERON COLONY

TABLE OF CONTENTS

TABLES

FIGURES

1.0 INTRODUCTION

BP has proposed to construct and operate a Cogeneration Project adjacent to its Cherry Point refinery. The Cogeneration Project site is located approximately 1.3 miles from the Birch Bay Great Blue Heron Colony, and the associated wetland mitigation areas are located within 0.6 to 1.4 miles of the colony, with more than 90 percent of the mitigation area more than a mile from it. The colony itself is located on land owned by BP, which has been permanently protected by a conservation easement.

Whatcom County has designated the Great Blue Heron as a species of local importance, and has expressed concern about the potential effect of the wetland mitigation plan on heron. In response to the County's concerns, BP agreed to try to modify its wetland mitigation plan to reduce or avoid potential impacts to herons and make the mitigation area more "heron-friendly." However, both BP and Whatcom County acknowledged that BP had been working with federal, state and local agencies for more than a year in developing the wetland mitigation plan, and the basic framework and goals of the plan had been established and would not change. Prior to preparing the Final Wetland Mitigation Plan for the BP Cherry Point Cogeneration Project, BP staff and consultants met with Whatcom County staff and consultants to discuss possible modifications of the wetland mitigation plan. The wetland mitigation plan has been revised in light of those discussions, and those revisions have been incorporated and reflected in the body of the Final Wetland Mitigation Plan and in this appendix.

At the request of Whatcom County, BP has also prepared this appendix to address heron issues specifically. This appendix provides some background information regarding the Birch Bay heron colony, describes the potential impacts of the mitigation plan on herons, and describes the measures that have been included in the wetland mitigation plan to avoid or mitigate potential adverse impacts on the herons. At Whatcom County's request, this appendix and referenced portions of the Final Mitigation Plan provide the information identified in Whatcom County Code section 16.16.730(B)(1)-(3). As a result of the changes summarized in this appendix, the Final Wetland Mitigation Plan avoids or minimizes potential adverse effects on herons, and the Final Wetland Mitigation now includes several features that will increase the usefulness of the wetland mitigation areas for heron foraging.

BP also has another proposed project for which the permit process is nearly complete called the Brown Road Materials Storage Area. For that project, BP has developed a Habitat Management Plan to address the Great Blue Heron. In connection with the Brown Road project, BP has also committed to develop an overarching management plan for their lands north of Grandview Road. The overarching plan is being developed in conjunction with Western Washington University. The Brown Road Project Habitat Management Plan has articulated management goals and objectives for that project’s wetland mitigation area, which is close to the Birch Bay heron colony. The overarching management plan has a broader scope, but will also address goals and objectives for herons. This appendix is intended to fit within the developing goals in the other management plans.

2.0 BIRCH BAY GREAT BLUE HERON COLONY

The Birch Bay great blue heron colony is located north of Terrell Creek and west of Jackson Road (T39N, R1W S1NE/SE) in the Cherry Point area of Blaine, Washington. The colony's location is shown on Figure F-1 of this appendix.

The Birch Bay colony is the third largest heron colony in the region and currently includes more than 300 breeding pairs (Eissinger, 2004). In addition to breeding, the herons from the colony utilize habitats in the vicinity of the refinery for foraging and staging.

Herons do not occupy the colony year-round. Instead, they have a relatively predictable annual cycle of (a) staging, (b) mate selection, courtship and nest building, (c) egg laying and incubation, (d) hatching and rearing, and (e) fledging and dispersal. This cycle spans approximately six months. Herons return to congregate in fields near the colony beginning in February or March for staging. They reenter the colony and begin nesting by about April 1st. Hatching begins in May. Fledging occurs in July and August. Herons then disperse in September and do not begin congregating near the colony again until the following February or March.

2.1 COLONY HISTORY

The following historical summary is based on the Birch Bay Great Blue Heron Colony Conservation and Stewardship Plan (Eissinger 1996) and subsequent information provided in BP's Birch Bay Great Blue Heron Annual Reports (Eissinger 1997-2003).

Prior to the mid 1980's little historical information is documented for the Birch Bay heronry. It is likely that there has been a thriving heron breeding population historically, given the upland forests, fields, marshes and extensive eelgrass throughout the Birch Bay area. No other heron colonies are known within the immediate area. The nearest known active heronry is a relatively new one located on the south side of Lummi Bay.

The first official record of the Birch Bay great blue heron colony is from 1983 Washington Department of Fish and Wildlife (WDFW) records. At that time, the colony location was described as south of Terrell Creek and north of Grandview Road approximately one quarter mile and west of Jackson Road. At that time 75 nests were recorded by a state biologist. Any subsequent visits to the heronry by the State for five years were unrecorded, and during that time the herons relocated. A study of aerial photos from 1986 reveal that the area to the south of Terrell Creek, approximately 20 acres, had been recently logged. It is evident the heronry had been located in the logged stand or immediately adjacent to it. Displacement of the heronry was not reported; however it is assumed.

In 1988, the heronry was reported to the north of Terrell Creek (Norman 1988) indicating that the colony had moved to its present location between 1983 and 1988. The colony was described as containing approximately 200 nests situated in cottonwood, alder, and conifers. The following year 1989, a survey of the Birch Bay heronry documented 230 nests in 158 trees (Norman 1989). It was also estimated that the heronry was relatively undisturbed due to its location. A bald eagle nest located within a mile to the west was identified as a potential disturbance due to predation. It was recommended that the property be purchased by the State Parks to provide long-term preservation of the heronry. In addition, the excellent quality of Terrell Creek's riparian habitat was noted and it too was recommended for acquisition and protection.

In 1992 the Birch Bay heronry was visited by a WDFW biologist and the current heron monitoring biologist, Ann Eissinger. The colony was reported to contain an estimated 150 nests and located in cottonwood, alder, birch, Sitka spruce, Douglas fir, and grand fir. The site had been purchased by ARCO Inc. and had been maintained in its natural state. However, a road easement to an adjoining property within 100 feet of the colony was in review by the State and County.

In 1993 approximately 199+ nests were reported for the colony (Norman 1993). Herons at that time were described as more easily disturbed by human presence near the colony than at other sites. Partial clearing in the vicinity occurred in December 1993. Further impacts to the herons by development were abated by the acquisition of a private inholding near the colony by ARCO Products Company.

Between 1994 and 1995 little information is available for the colony. A survey of the colony in 1994 documented 212 nests (addendum to Norman 1993). No data is recorded for 1995.

In 1996 ARCO Products Company granted a conservation easement on 77 acres containing the heron colony and adjacent forest land. At that time ARCO contracted a wildlife biologist to develop the Birch Bay Great Blue Heron Colony Conservation and Stewardship Plan (Eissinger 1996). As a result of this plan, active stewardship and ongoing scientific monitoring and mapping of the heronry ensued.

From 1997, systematic monitoring of the colony was instituted. Systematic monitoring includes weekly or biweekly site visits from March through August, a summer productivity survey, and a fall nest count. During the weekly monitoring visits, the colony is observed for breeding chronology, predation, and general status. An annual productivity survey provides a measure of breeding success. The autumn nest count occurs following leaf drop and establishes the total number of active nests or breeding pairs for the year. For 1997, 335 nests were counted. In the fall of 1997, private property adjacent to the south of the colony was logged. The winter of 1997/1998 saw a loss of some nest trees via blow downs.

In 1998, a second major, unexplained disturbance occurred in the colony. Young fledged prematurely and numerous nests were blown out of trees. The fall nest count showed noteworthy increase (91) in the number of active nests from 335 to 426 nests. Once again the winter of 1998/1999 damaged trees in the colony. The heavy snowfall and strong winds of the La Nina weather pattern blew down more nests and trees.

The third and most recent disturbance transpired in 1999. At the peak of breeding season, with chicks and eggs in the nests, the adults suddenly abandoned the colony. The cause of this abandonment was investigated; however, no explanation was unearthed. As a result, only 5 of the 317 active nests were known to fledge young. Also in 1999, ARCO granted a conservation easement on an additional 103 acres of field and forest near the heron colony, creating a 180-acre habitat preserve.

The herons returned to the colony in 2000 and resumed their normal nesting pattern. However, with the disturbances of the three previous years, the number of active nests once again decreased 40 percent from 1998. From 2000 to 2002 the total autumn counts averaged 260, which indicated stability. During the autumn of 2002, a bald eagle pair began building a nest to the southwest of the colony approximately 100 feet from the southern boundary of the colony. The nest had some activity in 2003, but appeared not to produce young to fledging age and may have failed earlier. Bald eagle predation in the heron colony fluctuates from year to year and in some years may be the source of disturbance and reduction of productivity.

Currently, the Birch Bay heron colony is active and continues to be stable, with solid growth in 2003 and 2004.

2.2 MONITORING AND STUDY OF THE BIRCH BAY HERONS

The Birch Bay heron colony is unique among heron colonies in the Pacific Northwest in the extent to which it has been monitored and studied. Since 1997, Ann Eissinger of Nakheeta Northwest Wildlife Services has been extensively monitoring the Birch Bay heron colony. From March to August each year, Eissigner makes weekly visits to the colony and foraging areas. Eissinger performs annual census counts and gathers observational information from volunteers. Based on the information gathered to date, Eissinger has prepared Figures F-1 and F-2 reflecting her observational data on heron staging and foraging activities.

Although Eissinger has gathered substantial information about the staging and foraging patterns of the Birch Bay heron colony, her efforts have focused primarily on the colony itself. URS biologists have spent considerable time in areas designated for wetland mitigation for the Cogeneration Project. In doing so, they have made incidental observations concerning heron use. However, no systematic study of heron use in the wetland mitigation areas has been performed.

In order to better understand and define heron use of all of the BP-owned lands surrounding the refinery, a year-long heron monitoring study is currently underway by Eissinger. The heron habitat study is surveying BP owned open spaces using a systematic fixed-point sample method. The study area includes eleven sample points, plus walk-in and drive-by areas for further coverage. The study area concentrates survey efforts within suitable habitat north of Grandview Road with additional areas to the west along Jackson Road and southeast of the refinery, north of Aldergrove Road (Figure F-3). The study began in March 2004 and will be completed in March 2005. Heron occurrence, behavior, and site conditions will be documented during systematic weekly observations.

2.3 BREEDING AREA

Great blue herons congregate each spring at breeding areas for annual nesting. Herons are colonial breeders and the nests are concentrated and relatively isolated. Herons nest in trees, usually in near-shore forests in close proximity to productive food sources. The Birch Bay heron colony is situated in the forest north of Terrell Creek, northwest of the Cherry Point refinery. The forested area is isolated and is generally inaccessible. The colony location gives the herons direct access to productive foraging areas including marine, fresh water, and upland fallow fields. There are also areas of roosting nearby along Terrell Creek. No other heron colony is known within the Birch Bay area.

The heronry is situated in a 50-70 year old forest composed of both coniferous and deciduous trees. Most or all of this area is forested wetland and contains saturated soil and shallow inundation for long durations during the wet season and extending into the growing season. The trees in which the Birch Bay herons are nesting are primarily western paper birch (*Betula papyrifera*) 64% and red alder (*Alnus rubra*) 29%, with conifer species such as grand fir (*Abies grandis*) and Douglas fir (*Pseudotsuga menziesii*) utilized to a lesser extent, 7%. Most heron colonies nest in mixed species forests, however each colony has a different species preference for nesting.

Heron nesting colonies are very sensitive to disturbance and, as a result, most sites are isolated and difficult to detect. The primary disturbance to colonies is typically human related, either through direct access or habitat alteration. As a result, management plans for heron colonies include peripheral buffers to separate the colony from potential human intrusion, noise or other disturbance. The Birch Bay heron colony is well protected by a forested buffer. The nesting colony itself occupies approximately two acres. It is surrounded by a 180-acre block of forested land that is owned by BP and protected by a conservation easement.

2.4 STAGING AREAS

The Birch Bay heron colony stages in the fallow fields along Terrell Creek northwest of the Cherry Point Refinery. Staging is an important part of a heron's lifecycle. It is defined as a gathering of adult herons in fields, other open space, or sometimes trees, prior to entering the colony area for nesting. Staging is considered a vital part of the breeding cycle and social structure of the colony. Herons generally concentrate in specific areas for staging that are used each year.

Since 1997 the staging for the Birch Bay colony has occurred in the fallow fields directly east of the colony. The area most frequently used is immediately east of Jackson Road. Some herons stage in scattered groups to the south of the colony and further east of the main staging area. The staging areas used by the herons are identified on Figure F-1 by yellow crosses depicting the common area of concentration and by a broken green line illustrating the areas of use by individuals and smaller or loose aggregations.

2.5 FORAGING AREAS

Herons forage in a variety of habitats. Foraging areas include marine shorelines, the intertidal zone, wetlands, streams, riparian areas, and upland fallow fields. Prey sought by herons include fish (marine and freshwater), crustaceans (marine and freshwater), amphibians (freshwater and upland), and small mammals (upland). The primary prey species of great blue herons identified by regional researchers include: marine: crescent gunnel (*Pholis laeta*), saddleback gunnel (*Pholis oranta*), marine sculpins (various species), shiner perch (*Cymatogaster* aggregate), and smelt (*Hypomesus* spp., *Thaleichtys* spp.); freshwater: sculpins, frogs (*Hyla* spp., *Rana* spp.), and crayfish; and upland: Townsend's vole (*Microtus townsendii*). The most concentrated foraging during the nesting season occurs in the intertidal areas near the colony.

The primary feeding locations for the Birch Bay colony are Birch Bay, Drayton Harbor, Semiahmoo Bay and Lummi Bay (Figure F-2). Herons travel from their colonies to the foraging areas along common flight paths or flyways. The distance between the colony and these areas are: Colony to Birch Bay – 1.88 miles; Colony to Lummi Bay – 8.13 miles; Colony to Drayton Harbor/Semiahmoo Bay – 5.5 miles. Drayton Harbor and Semiahmoo Bay have the largest concentrations of foraging herons and are considered the foraging areas where the Birch Bay Colony concentrates its foraging activities. These foraging areas are extremely important, particularly to breeding herons and young due to high seasonal prey availability and easy access by large concentrations of herons at one time. The most important of these foraging areas are the intertidal eelgrass meadows, which harbor high densities of prey.

Additional feeding areas are utilized by individuals or small aggregations of herons. These areas are utilized year-round, particularly during unfavorable tides, and do not necessarily support large concentrations during the breeding season. These additional feeding areas associated with the Birch Bay colony include Lake Terrell, the Terrell Creek Corridor, and the fallow fields adjacent to the heron colony. These areas provide foraging habitat for the herons during high tide when intertidal foraging is limited to the shoreline and during the winter when low tides are generally nocturnal. The Cherry Point shorelines also are used by individuals and small aggregations when conditions are favorable. Lake Terrell and fallow fields north of the refinery have limited use by the herons during the fall and early winter when the activities of upland bird and waterfowl hunting season causes the herons to avoid these areas due to disturbance from dogs and hunters. Although these additional foraging areas are not utilized by large concentrations of herons, they are important, particularly fallow fields, for winter survival and access to food during unfavorable tide cycles. Individuals may range widely to use these habitats over a large part of the county and adjoining areas, particularly outside the nesting season.

3.0 WETLAND MITIGATION PLAN

3.1 GENERAL DESCRIPTION OF THE PROPOSED COGENERATION PROJECT AND WETLAND MITIGATION PLAN

BP's proposed Cherry Point Cogeneration Project will be located at the corner of Grandview Road and Blaine Road (T39N R1E S8NW), adjacent to the BP Refinery in the Cherry Point Heavy Industrial Area of Whatcom County, Washington. Wetland mitigation for the Cogeneration Project will occur in the open fields directly north of the construction site, north of Grandview Road, on both the east and west sides of Blaine Road. Figure 1 of the mitigation plan illustrates the locations of the construction and wetland mitigation areas, the heron colony, and local landscape features.

The wetland mitigation plan includes two compensatory mitigation areas (CMAs), which together occupy approximately 110 acres. CMA 1 will be located across Grandview Road from the cogeneration facility, east of Blaine Road, and south of Terrell Creek, and is approximately

50 acres in size. CMA 2 will be located on about 60 acres across Grandview Road from the cogeneration laydown area, west of Blaine Road, and south of Terrell Creek. Both CMA 1 and CMA 2 are currently primarily open fields with a mosaic of wetland and upland conditions (see Figures 5A and 5B of the Cogeneration Project Wetland Mitigation Plan to which this appendix is attached). Modifications to CMA 1 and CMA 2 are planned to compensate for permanent wetland impacts associated with the Cogeneration Project, primarily by changing hydrology and enhancing existing wetlands and plant communities. Invasive weedy species will be removed and replaced by native species. Habitat diversity and structure will be restored by planting a variety of native meadow grasses, shrubs and trees. Historical hydrologic pathways and functions will be restored by plugging existing ditches, spreading treated stormwater across CMA 2 and creating several small seasonal ponds. As part of the mitigation, the farming lease on the CMAs would be terminated.

3.2 MITIGATION AREA EXISTING CONDITIONS

CMA 1 and CMA 2 are currently primarily open fields with a mixture of wetland and upland habitats. Approximately 80 acres of the combined 110 acres of the CMAs has been determined to be jurisdictional wetlands. Approximately one-third of the wetlands (or 24 acres) are seasonally inundated. Figures 6A and 6B in the Final Mitigation Plan show the wetlands (both seasonally saturated and seasonally inundated) and upland areas. Several ditches remaining from former active farming continue to function in draining the sites, although they have not been maintained for years and typically are overgrown by weeds, shrubs, and trees. While some of the wetlands are inundated with shallow water during the wet season, there are no permanent open water features in the CMAs. Topography of the CMAs is shown in Figures 5A and 5B of the Mitigation Plan, and the ditch flow paths are shown in Figures 6A and 6B

The CMAs consist primarily of open-field habitat. Forested vegetation can be easily distinguished from open field habitat in the aerial photographs used as the background of Figures 6A and 6B.

Both CMA1 and CMA2 have been leased to a cattle farmer for several years. Under the lease, CMA 1 has been utilized as pasture for grazing cattle and a large part of CMA 2 has been mowed for hay annually.

Current vegetation cover in the CMAs as distributed between uplands, seasonally inundated wetlands, and seasonally saturated wetlands is given in Table 1 and Table 2 below.

Table 1 Vegetation Cover in Acres in CMA 1

Cover Type	Upland	Seasonally Inundated	Seasonally Saturated	Total
Forest/Shrub	1.5	.5	0	2.0
Dominated by Reed Canarygrass	2.5	9	14	25.5
Dominated by Other Herbaceous Species	8	2.5	12	22.5
Total	12	12	26	50

CMA 1 is now grazed by cattle under the farm lease covering the parcel. Therefore the habitat of CMA 1 is not conducive to production of voles that might attract herons to the parcel. If grazing were not occurring, then about 8 acres of upland would potentially be attractive to voles and herons. About 14.5 acres of wetland that is not dominated by reed canarygrass would be potentially available, but would be less productive of voles. Also, no seasonal ponds or open water suitable for amphibian reproduction exist within CMA 1.

Table 2 Vegetation Cover in Acres in CMA 2

Cover Type	Upland	Seasonally Inundated	Seasonally Saturated	Total
Forest/Shrub	3	.5	.5	4.0
Dominated by Reed Canarygrass	2.5	9	11	22.5
Dominated by Other Herbaceous Species	12.5	2.5	18.5	33.5
Total	18	12	30	60

Under the current farm lease, about 35 acres of CMA 2 is typically mowed for hay. The area is not necessarily identical every year. The mowed area occupies most of the east and north sections of CMA 2 and is spread across uplands, seasonally saturated wetlands, and seasonally inundated wetlands. With most of the vegetative cover removed, these areas become less attractive for voles and therefore for herons. If the mowing did not occur, the 12 acres of upland field not dominated by reed canarygrass would be the most attractive to herons for feeding. About 21 acres of wetland not dominated by reed canarygrass would potentially be available, but would be less attractive to voles. Also, no open water suitable for amphibian reproduction exists in CMA 2.

3.3 CURRENT AND POTENTIAL HERON USE OF MITIGATION AREAS

As explained in section 2.2 above, no systematic study of heron usage in the CMAs has been conducted. Based on the best information that is available, however, heron use of the CMAs is believed to be minimal. Neither breeding nor staging occurs in the CMAs. Eissinger has observed occasional foraging by individuals or small groups of herons in the western panhandle of CMA2, but has not observed foraging in CMA1. URS wetland biologists have been on the ground in the CMAs many times in all seasons since the fall of 2001 and in other parts of BP's land north of Grandview Road repeatedly since 1999. During those visits, herons have frequently been seen to the west of the CMAs, close to the heronry, along the permanent ponds, and in fields closer to Jackson Road. Herons have been infrequently seen in the western part of CMA 2 in the northwestern "panhandle", but no herons have been seen in CMA 1 or the eastern 90 percent of CMA 2.

Nonetheless, some consider any open field area within 4 miles of the heron colony to be potential heron habitat (Stenberg 2003). Herons could forage for prey in open fields near the colony as a supplement to prey found in the marine tidal areas or as a substitute when the tides and other conditions make the marine tidal areas unavailable, or at times when it is important for herons or their young to remain close to the colony. (Stenberg 2003). In addition, individual herons may feed in open field habitats at any time, but are seen in such situations particularly during the winter when days are short and tides are unfavorable for intertidal foraging.

Potential prey species that may be available for herons in the CMAs include voles and native amphibians. Herons are known to use open fields with fallow grass cover to hunt for voles. Ideal conditions for herons to find voles is habitat with dense grass cover that is not tall enough to completely obscure the voles from the herons' view. Voles make runways in the grass where they travel over the surface of the ground. Where the grass is too sparse to provide cover (such as in mowed or heavily grazed areas) use by voles is limited. The predominant species of vole in the Cherry Point area is one that tends to choose drier substrate rather than wetland areas.

The vegetation cover of the CMAs, while recognized as primarily open-field habitat, includes extensive patches of cover that is less than ideal for heron foraging. Of the 110 acres in the CMAs, about 6 acres is occupied by scattered trees and dense shrubs like hardhack and blackberries, which makes those areas inaccessible to herons for foraging. In addition, about 45 to 50 acres is dominated by dense reed canarygrass that, if not mowed, is tall and dense enough to obscure the voles from sight by the herons and reduce the effectiveness of their hunting. Therefore, under current land use patterns by the lessee, only about 20 acres of the CMAs might qualify as attractive foraging habitat for herons. If the lease activities were not occurring, about 55 acres would be suitable in terms of ground cover, but only about 20 of those acres would be upland. The rest would be wetland that would not be ideal for voles during the winter when voles are most important to herons.

Likewise, the CMAs currently provide less than ideal habitat for preying on native amphibians. None of the wetlands on the CMAs currently provide breeding habitat for amphibians. In addition, the CMAs do not provide the forested or shrub habitat required for the terrestrial stages of the amphibians' life cycle. The distance from such breeding habitat across less than ideal habitat conditions for adult amphibians suggests that the expected level of amphibian occurrence on the CMAs is too low to make the CMAs attractive for herons to forage on amphibians. This corresponds with on-the-ground observations by wetland biologists. Amphibians have been encountered much less here than in other parts of BP's property north of Grandview Road where native amphibian habitat is more prevalent.

3.4 POTENTIAL IMPACTS TO HERONS & MEASURES TO AVOID AND MITIGATE IMPACTS

Herons are not expected to be adversely affected by the creation and maintenance of the wetland mitigation areas associated with the Cogeneration Project. Nonetheless, several potential impacts to herons and their potential habitat were considered and measures were developed to avoid or minimize those potential impacts. Features have also been added to improve the habitat for heron foraging. The potential impacts and the measures to offset them, as well as the added beneficial features, are addressed below.

3.4.1 Disruption due to initial creation of mitigation areas

A major component of the Wetland Mitigation Plan is the eradication of invasive plant species such as reed canary grass and blackberry bushes. The current distribution of reed canary grass in the CMAs is shown on Figures 7A and 7B of the Wetland Mitigation Plan. The initial removal of reed canary grass, blackberry bushes and other invasive species will involve tilling and the application of herbicides in these areas. The tilling and herbicide application activities will occur over a period of approximately two months. On any given patch, these activities will occur intermittently, a few days total spread over the treatment period. Tilling will be accomplished using motorized equipment such as tractors. The tilling is performed in order to disrupt vigorous spring growth, break up the rhizomes, and encourage sprouting of dormant seeds and rhizome pieces so that they can be killed by herbicide treatment. It is important to break up the rhizomes in order to get the herbicide into all parts. The herbicide application occurs after vigorous regrowth is underway and therefore follows the tilling a few weeks later. These actions must occur during the spring and early summer when growth is most vigorous in order to be effective and to prevent a new crop of seeds from setting. Herbicides will be applied using motorized equipment for the initial treatment. Follow-up treatment for persistent patches and new sprouts will be done by hand, even after other plantings have been installed.

The initial creation of the mitigation areas will also involve some limited excavation and earth movement to fill existing ditches and restore historic hydrology. This excavation and earth movement will be accomplished using motorized equipment such as bulldozers. The earthwork is expected to take two months or less and will be conducted during the dry months of late summer and early fall (therefore will not occur outside of the WDFW heron management guidelines of July 31 to Feburary 15).

After invasive species are eradicated, native species will be planted in the mitigation areas according to the planting plan provided in Figures 11A and 11B. Initial planting of herbaceous species is expected to occur in early fall (perhaps a 2-week duration) and woody species in late fall and early winter (about a 2-month duration), with a few species likely to be installed in early spring. Initial planting will be done in phases and the phases are likely to extend over a period of 3 years (see Section 10 of the Cogeneration Project Wetland Mitigation Plan). Initial planting will involve small motorized equipment and hand labor. The intent will be to complete planting between July 31 and February 15. However, if conditions or circumstances require planting outside that window, then Whatcom County Planning and Development Services will be notified and appropriate monitoring and protective measures will be agreed upon before planting proceeds.

CMA 1 and CMA 2 are located a sufficient distance from the heron colony and staging areas so that the activities associated with creating the mitigation areas are not expected to disturb heron nesting and staging. However, it is possible that the activities associated with the initial creation of the mitigation areas could discourage foraging in CMA 1 and CMA 2.

The scheduling of most of the initial work to create the wetland mitigation areas should minimize disturbance of herons. The earthwork can best be done during the dry season, which coincides with the end of the fledging and the dispersal of the herons from the colony and therefore should be considered advantageous timing. Most of the planting will occur in fall and winter when the herons are widely dispersed and not concentrated at the colony. However, the activities required to eradicate invasive species, reed canarygrass in particular, must occur during the spring and early summer to be effective. Construction timing is discussed in more detail in Section 10.0 of the Mitigation Plan.

3.4.2 Disruption during on-going maintenance activities

In years following the initial creation of the wetland mitigation areas, on-going maintenance will be required in the wetland mitigation areas. The Final Mitigation Plan contains specific performance standards and requires monitoring and contingency measures to be taken if those standards are not met (see Section 9.0 of the Mitigation Plan). During the first several years, additional invasive species (reed canarygrass and blackberry) eradication efforts will be necessary, and additional native species will be planted to replace plants that do not survive. These activities will include hand work or small motorized equipment. These activities will occur for only a few days at a time over the spring, summer, and fall of the 10-year monitoring period. The timing of the activities is based on the effects of weather patterns of the year and the most effective time for the particular activity. For example, the timing of some weed control activities may vary by weeks from year to year depending on the late winter and spring weather pattern. However, if conditions or circumstances require maintenance activities to occur more than 5 days in 30 days between February 15 and July 31, then Whatcom County Planning and Development Services will be notified and appropriate monitoring and protective measures will be agreed upon before maintenance activity proceeds.

Due to the distance from the heron colony, these activities are not expected to affect heron nesting or staging. These activities could temporarily discourage heron foraging in the mitigation areas. However, these maintenance activities are essential to the overall success of the wetland mitigation plan. The federal wetlands permit will impose strict performance standards for reed canary grass removal, and on-going maintenance must be performed at the time when it will be effective in order for those federal requirements to be met.

3.4.3 Reduction of open field foraging area and improvement in habitat quality

CMA 1 and CMA 2 currently provide 110 acres of potential heron foraging habitat. However, as discussed above in section 3.2 of this appendix, only about 20 acres currently provide habitat that is likely to be attractive for heron foraging. Even without the activities of the farmer who currently leases the land, only about 20 acres would be attractive to the herons during a large part of the year because of the dense stands of reed canarygrass and the amount of wetland.

The mitigation plan activities include converting a substantial part of the CMAs from open field habitat to tree or shrub habitat, thus reducing the amount of open-field habitat available for herons to use in foraging. As a result of concerns expressed by Whatcom County, changes have been made to wetland mitigation plan. The planting plan now maintains at least 23 acres in open field habitat for the herons. As agreed upon with the County's staff and consultant, emphasis has been placed on locating the open field habitat in CMA2, which is closer to the heron colony and more likely to be used in the future by herons for foraging. In addition, several features have been designed to improve the quality of that habitat for heron foraging.

According to the planting plan (Figures 11A and 11B), the mitigation areas would be planted to contain a variety of habitat types. The mitigation areas would consist of approximately 23 acres of open field, 7 acres of shrub, 79 acres of forest and 1 acre of seasonal ponds. Although the planned planting would reduce the total amount of open field within the CMAs, the habitat most suitable for heron foraging would be not be decreased, and the usefulness of the remaining habitat for heron foraging will be improved significantly.

The effects of the changes in CMA 1 and CMA 2 that would occur as a result of the wetland mitigation actions have been evaluated with respect to current and potential heron use of the CMAs. The wetland mitigation plan has been modified to specifically address the effects on potential heron habitat and use. Tables 3 and 4 summarize the expected habitat conditions for herons in each of the CMAs.

Table 3 Proposed Vegetation Cover in Acres in CMA 1

Cover Type	Upland	Seasonally Inundated	Seasonally Saturated	Total
Forest/Shrub	11	11.5	21	43.5
Dominated by Reed Canarygrass[1]	0	0	0	0
Dominated by Other Herbaceous Species	1	1	4	6
Seasonal Pond	0	.5	0	.5
Total	12	13	25	50

1. Cumulative Reed Canarygrass cover could be as high as 10% to 20% during the early years of the mitigation, but by the end of the monitoring period there will be no more than 10%. No area as large as an acre will be dominated by Reed Canarygrass.

Table 4 Proposed Vegetation Cover in Acres in CMA 2

Cover Type	**Upland**	**Seasonally Inundated**	**Seasonally Saturated**	**Total**
Forest/Shrub	10	22	11	43
Dominated by Reed Canarygrass[1]	0	0	0	0
Dominated by Other Herbaceous Species	7	2.5	7	16.5
Seasonal Pond	0	.5	0	.5
Total	17	25	18	60

1. Cumulative Reed Canarygrass cover could be as high as 10% to 20% during the early years of the mitigation, but by the end of the monitoring period there will be no more than 10%. No area as large as an acre will be dominated by Reed Canarygrass.

Open areas have been designed to be large enough to accommodate easy entry and exit by birds as large as the great blue heron. The longest dimension of the patches ranges from more than 400 feet long to more than 1100 feet long, and the patches range from 3 acres to over 6 acres in area. Three of the open areas have been located in such a way that they will connect with adjacent open field areas located outside the CMAs to further enhance the likely use by herons. Two of those areas link with similarly designed open areas on the Brown Road Mitigation Area, as illustrated by aligning Figure 10A in the Brown Road Material Storage Area Final Mitigation Plan with Figure 11B of the Cogeneration Wetland Mitigation Plan. The third area is along the east edge of CMA 1 and links to open field habitat to the east.

The quality of the open field habitat that remains will be improved in several ways by the mitigation plan. Large and small woody debris will be distributed in meadow areas to promote small mammal concentrations, which herons may utilize as prey (see section 5.6.4 of the Cogeneration Wetland Mitigation Plan). Twelve small seasonally inundated ponds and emergent wetlands will be strategically located to increase breeding of native amphibians, which herons also may use as prey (see Figures 11A and 11B of the Cogeneration Wetland Mitigation Plan). Reed canarygrass and blackberry-occupied open fields will be replaced with meadow grass fields that are more accessible and which herons are expected to favor for foraging. Shrubs will be added in small clumps to provide windbreaks, which herons have been observed to prefer when foraging in fields near the colony (Eissinger 2004).

3.4.4 Impacts to prey species from hydrologic modifications

A major component of the wetland mitigation plan is the restoration of historic hydrology in the mitigation areas. Changes in the hydrology could adversely affect available prey species if it made areas too wet to support small mammals such as voles, or if it created habitat for bull frogs that could reduce the number of native amphibian prey species. The mitigation plan has been designed to avoid these potential problems.

Small portions of the mitigation areas that are currently upland are likely to become seasonally inundated wetlands (perhaps as much as 3 acres total). These areas would not support small mammals such as voles when inundated, but would be repopulated during the dry months. In order to compensate for this temporal effect, the mitigation plan will enhance other open meadow habitat by replacing reed canary grass and blackberries with meadow grasses in which small mammals thrive year round. In addition, woody debris placed in the meadows will improve utilization by voles.

Measures will be taken to prevent any portions of the wetland mitigation areas from becoming bullfrog habitat. The bullfrog lifecycle requires year-round open water habitat. The mitigation areas will not contain any year-round open water. Twelve seasonally inundated ponds will be created, cumulatively occupying approximately about one acre (see Cogeneration Wetland Mitigation Plan Figures 11A NS 11b). These ponds will encourage native amphibian growth, making more prey species available, but will not provide bullfrog habitat because they will not contain water year-round. The seasonal ponds have been strategically located to favor access to most of them by herons. Even ponds not accessible to herons will produce amphibians that may be available in other parts of the vicinity. The planting of forest and shrub habitat is also important, because the adult phases of native amphibians require such habitat accessible from the breeding ponds. The seasonal ponds will be monitored and contingency actions will be taken, if necessary, to ensure that they remain seasonal in nature (see Section .8 of the Cogeneration Wetland Mitigation Plan).

3.4.5 Creation of connected forested areas

The wetland mitigation plan includes the creation of approximately 79 acres of forested wetland and upland habitat. These forested areas are shown on Figures 11A and 11B. The forest plantings will connect existing forest areas along Terrell Creek with seasonal ponds within the CMAs. This connectivity is considered desirable because herons from the Birch Bay colony have been observed preferentially flying along tree lines to reach foraging areas. In addition, the connections with other habitat patches will benefit other wildlife species.

3.5 EXPECTED OUTCOMES

Overall, the proposed mitigation will maintain an area equivalent to or greater than the currently effective potential foraging area for herons in the CMAs. A comparison of existing and expected habitats from several ways of looking at it is provided in Table 5. The quality of the open field habitat will be improved in several ways to produce more potential heron prey and be more accessible for heron use. Therefore, the end result is expected to be a net improvement for herons over existing conditions.

Table 5 Comparison of Existing and Expected Heron Habitat in Acres

Habitat Type	Existing Area	Existing Effective Foraging Area	Planned Area	Expected Effective Foraging Area
Overall Habitat:				
Open field	104	20.5	22.5	22.5
Tree-shrub	6	0	86.5	0
Seasonal pond	0	0	1	1
Subtotal	110	20.5	110	23.5
Wetland Habitats:				
Seasonally inundated herbaceous wetland	24	0	3.5	3.5
Seasonally saturated herbaceous wetland	56	0	11	11
Seasonally inundated forested/shrub wetland	1	0	33.5	0
Seasonally saturated forested/shrub wetland	0	0	32	0
Seasonal pond	0	0	1	0.5
Subtotal	81	0	81	15
Degraded Habitat:				
Open field grazed by cattle	50	0	0	0
Open field mowed	35	0	0	0
Subtotal	85	0	0	0

In the long term, the forest planted in the CMAs has the potential to become attractive as a site for the heron nesting colony. This may be important, as natural succession and weather events can combine to make the current nesting colony site cease to function. However, natural succession also has the potential to fill in meadow areas with trees, thus reducing the open field foraging area available to the herons. No active elimination of trees is planned to ensure that areas planted with herbaceous vegetation remain open fields in perpetuity. However, trees that try to establish in areas planted as herbaceous habitat in the initial plantings will be treated as weeds and removed during the ten-year monitoring and maintenance phase (see Section 8 of the Cogeneration Wetland Mitigation Plan).

4.0 ADAPTIVE MANAGEMENT

The Final Wetland Mitigation Plan has been developed based upon the best information available at this time. Additional information regarding heron habitat utilization and hydrology is expected to be available prior to the implementation of the wetland mitigation plan. The mitigation plan will be adapted as appropriate when that additional information becomes available.

In particular, the year-long heron monitoring study discussed above will be completed in March 2005, prior to the implementation of the wetland mitigation plan. This study should provide additional more detailed information regarding heron utilization of the wetland mitigation areas. The mitigation plan will be adjusted as appropriate to minimize temporary and permanent impacts to herons and to increase the benefits to the local heron population. Such adjustments may include altering the planned planting schemes, planned hydrologic patterns, and proposed habitat features. For example, if the heron monitoring results showed that herons are spending significant time foraging in wetlands with amphibians, then more seasonal ponds could be added.

In addition, the monitoring of the mitigation areas in the first 10 years after establishment will generate information that will point out any differences in what is achieved compared with what was planned. Analysis of the causes of the differences may result in the need for contingency measures to be implemented. The effects of the contingency measures on herons will be considered as part of the analysis and implementation of the measures. For example, if plantings in a certain area are not successful as planned, the location of area to be replanted could be shifted, but the potential effects on the amount of effective heron habitat would be considered in determining the adaptation. The overall goal of maintaining the planned level of effective heron habitat will be one of the guiding principles in meeting the performance standards of the wetland mitigation plan as adaptive management is applied to the mitigation area.

5.0 REFERENCES

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Appendix F Figures - F-1, F-2, and F-3 Not Available On-line

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